COST OF SERVICE SUMMARY

1.0 INTRODUCTION

This evidence presents an overview of Hydro One Distribution's Cost of Service evidence. As summarized in Exhibit C2, Tab 1, Schedule 1, the Cost of Service includes the following elements, for which the overall costs for 2015 through 2019 are shown in Table 1 below:

- Operation, Maintenance and Administrative ("OM&A") Expenses,
- Depreciation and Amortization Expense, and
- Payments in Lieu of Corporate Income Taxes.

Table 1
Costs of Service ($ Millions)

Line no.	Description	Test Year				
		2015	**2016**	**2017**	**2018**	**2019**
1	OM&A	564.3	610.2	614.0	603.9	600.0
2	Depreciation and Amortization	353.6	373.2	390.5	404.6	416.6
3	Income Taxes	55.6	61.6	62.2	65.6	69.4
4	**Total Cost of Service**	**973.5**	**1,045.0**	**1,066.7**	**1,074.1**	**1,086.0**

2.0 KEY ELEMENTS OF THE COST OF SERVICE

Hydro One Distribution's forecast cost of service has been developed consistent with corporate strategic goals to improve customer satisfaction, provide safe and reliable service and improve overall system reliability. The Company's planning process is described in detail in Exhibit A, Tab 17, Schedule 1.

Each of these components is separately addressed within the company's evidence. Exhibit reference numbers are provided below.

1.1 Operation, Maintenance and Administration Expenses (OM&A)

Total OM&A expense for the test years 2015 through 2019 are shown in Table 2 below.

Hydro One Distribution plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the company. These work programs primarily address improvements in infrastructure and improvements in productivity and efficiency. Exhibits in support of OM&A costs have been prepared by program area, and appear within the submitted evidence as follows:

Table 2
Summary of OM&A Expenses ($ Millions)

Program Areas *($ millions)*	**2015 Total Cost**	**2016 Total Cost**	**2017 Total Cost**	**2018 Total Cost**	**2019 Total Cost**
Sustaining *Ref: Exhibit C1, Tab 2, Sch 2*	329.5	374.4	380.1	363.2	358.1
Development *Ref: Exhibit C1, Tab 2, Sch 3*	15.4	17.7	17.0	17.3	17.8
Operations *Ref: Exhibit C1, Tab 2, Sch 4*	30.2	34.3	34.8	42.2	41.0
Customer Care *Ref: Exhibit C1, Tab 2, Sch 5*	117.8	116.3	114.7	113.5	115.4
Corporate Common Costs and Other Costs *Ref: Exhibit C1, Tab 2, Sch 6*	66.7	62.5	62.4	62.4	62.3
Taxes Other Than Income Taxes *Ref: Exhibit C1, Tab 2, Sch 12*	4.7	4.9	5.0	5.2	5.4
Total OM&A Expenses	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

1.5 Depreciation and Amortization Expense

The depreciation and amortization expense accepted by the Board for Hydro One's 2010 and 2011 Electricity Distribution revenue requirement, followed the methodology originally accepted by the Board for 2006 rates. The depreciation rates in the RP-2005-0020/EB-2005-0378 proceeding were supported by an independent depreciation study completed in June 2005 by Foster Associates Inc. (Foster Associates). The Board accepted the costs flowing from this depreciation study for the purpose of supporting Hydro One Disitrbution's rates in 2006 and similarly accepted the methodology again in the 2007-0681 proceeding for 2008 rates. A new full depreciation study covering Hydro One Networks' distribution and common assets was initiated and carried out by Foster Associates in the summer of 2013 for purposes of determining depreciation and amortization expense for the 2015 – 2019 test years.

Hydro One is proposing to recover the depreciation and amortization expense in the following amount for each of the test years: 2015 - $353.6 million; 2016 - $373.2 million; 2017 - $390.5 million; 2018 - $404.6 million; and 2019 - $416.6 million. Hydro One Distribution's evidence regarding the depreciation study and its impact on depreciation expense is filed at Exhibit C1, Tab 6, Schedule 1.

1.6 Payments in Lieu of Corporate Income Taxes

As a result of the *Electricity Act, 1998*, Hydro One Distribution has been required to pay proxy taxes since 1999. Hydro One is requesting recovery of Payments in Lieu of Income Taxes ("PILs") in the following amount for each of the test years: 2015 - $55.6 million; 2016 - $61.6 million; 2017 - $62.2 million; 2018 - $65.6 million; and 2019 - $69.4 million. Evidence outlining the calculation of PILs is filed at Exhibit C1, Tab 7, Schedule 1 and Exhibit C2, Tab 5, Schedule 1.

1.7 Taxes Other Than Income Taxes

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 12.

SUMMARY OF OM&A EXPENSES

1.0 SUMMARY OF OM&A EXPENSES

The requested OM&A expenses result from the rigorous business planning and work prioritization processes described in detail at Exhibit A, Tab 17, Schedules 1 through 6. These processes reflect a risk-based decision making approach to ensure appropriate and cost effective investments. The development of asset maintenance programs follows good utility practice and is based on the consideration of a number of risk factors as discussed in Exhibit A, Tab 17, Schedule 7.

Hydro One Distribution's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Services, Common Corporate Costs and Other OM&A, and Property Taxes & Rights Payments. Table 1 provides a summary of Hydro One Distribution’s OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of Distribution OM&A Budget
($ Millions)

Description	Historical Years						Bridge Year	Test Years				
	2010	2010 Approved	2011	2011 Approved	2012	2013	2014	2015	2016	2017	2018	2019
Sustaining	305.9	315.2	317.1	337.5	307.9	318.1	320.4	329.5	374.4	380.1	363.2	358.1
Development	12.3	11.7	15.8	12.0	14.7	12.1	18.4	15.4	17.7	17.0	17.4	17.8
Operations	18.5	20.2	18.1	20.9	21.0	22.7	30.4	30.2	34.4	34.8	42.2	41.0
Customer Services	114.7	117.2	113.3	113.4	116.7	137.3	133.7	117.9	116.3	114.7	113.5	115.4
Common Corporate Costs and Other OM&A	94.9	50.9*	85.5	46.5*	88.6	102.8	73.8	66.7	62.5	62.4	62.4	62.3
Property Taxes & Rights Payments	4.6	4.7	4.6	4.8	4.5	4.5	4.6	4.7	4.9	5.0	5.2	5.4
TOTAL	**550.9**	**520.0**	**554.4**	**535.0**	**553.4**	**597.5**	**581.3**	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

* The envelope reduction to OM&A from the OEB Decision was not spread across the work program areas but was included in other OM&A.

OM&A spending in 2010 and 2011 was higher than Board Approved levels after the envelope reductions in the OEB Decision, to fund the necessary work that Hydro One had to complete in each year.

Total OM&A expenditures for 2015 are decreasing by $17 million or 3% over the projected 2014 bridge year expenditures. Total OM&A expenditures will increase to a peak level of $614.0 million in 2017, but then decrease from 2018 to $600.0 million in 2019. Contributing to the increase in OM&A expenditures is a growth in sustainment expenditures driven primarily by the continuing efforts to address a backlog of vegetation management to manage costs and improve reliability; an increase in PCB testing of oil filled equipment to meet requirements set out by Environment Canada regulations; and an increase in meter verifications to meet requirements set out by Measurement Canada regulations. The slight increases in development expenditures are primarily attributed to the work required to conduct studies which explore viable options for future smart grid investments. Also contributing to the total increase in OM&A is the increase in Operations spending to maintain and support of the Distribution Management System.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing components of the distribution system to ensure the system will continue to function as originally designed as well as ensure public and employee safety, provide an acceptable level of reliability and deliver on customer commitments. Details of the expenditures under this program are provided at Exhibit C1, Tab 2, Schedule 2.

3.0 DEVELOPMENT

The Development OM&A program consists of system voltage and loading data collection, as well as system and generation connection studies to enable the safe and reliable operation and expansion of the distribution system. This program also ensures appropriate standards are maintained as required to meet construction, legal and regulatory requirements. Details of the expenditures under this program are described in detail at Exhibit C1, Tab 2, Schedule 3.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the work carried out at Hydro One's Ontario Grid Control Centre. Distribution Operations is involved with the real time monitoring and operation of the distribution system, including the coordination of planned outages and the dispatch of field crews in response to distribution system problems (trouble calls) received by the Customer Contact Centre. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 4.

5.0 CUSTOMER SERVICES

The Customer Services OM&A work program represents the set of work activities required to provide services to customers connected to Hydro One Distribution’s system and to meet the service levels stipulated in the Electricity Distribution Rate Handbook. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 5.

6.0 COMMON CORPORATE COSTS AND OTHER OM&A

The Common Corporate Costs and Other OM&A program includes the provision of Common Corporate Functions and Services (CCFS) and Asset Management programs to support the Distribution business, as well as the maintenance of existing infrastructure, including business systems and information technology. CCFS includes the provision of financial, human resources, communications, regulatory, legal and real estate services. Asset Management programs include developing distribution asset strategies, policies and standards and planning and prioritizing specific OM&A and Capital work on the distribution network. Other programs include information technology support and the cost of goods sold in support of external revenues. Other OM&A includes the credits for capitalized overheads. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedules 6 to 11.

7.0 PROPERTY TAXES & RIGHTS PAYMENTS

This OM&A cost consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 2, Schedule 12.

SUSTAINING OM&A

1.0 INTRODUCTION

Distribution sustaining OM&A represents expenditures required to maintain existing components of the distribution system to ensure they will continue to function as originally designed.

Hydro One Distribution manages its Sustaining OM&A program by dividing the expenditures into the following four categories:

- Stations – Expenditures that fund the work required to inspect, repair or maintain distribution stations or individual station components, as well as assess and carry out remedial work to reduce environmental contamination at distribution stations;
- Lines – Expenditures that fund the work required to inspect, repair or maintain distribution line sections or individual line components;
- Meters, Telecom, and Control – Expenditures that fund the work required to inspect, repair and maintain metering and control equipment, perform meter verification, and fund the cost of leasing telecommunication circuits; and
- Vegetation Management – Expenditures that fund the work required to keep assets clear of unwanted vegetation.

Sustaining OM&A investments are intended to maintain the viability of the distribution system, ensure public and employee safety, provide an acceptable level of reliability, deliver on customer commitments, and comply with all legislative, regulatory, and environmental requirements.

A summary of Hydro One Distribution's sustaining OM&A program and proposed spending levels for the test years 2015 to 2019 are described herein.

2.0 SUSTAINING OM&A SUMMARY

The sustaining OM&A programs fund both planned work and unplanned demand work. The planned OM&A work involves the inspection, verification, maintenance or repair of existing distribution system assets. Asset inspections are crucial in locating substandard or hazardous conditions in the distribution system and are required by the Distribution System Code in accordance with Appendix C. Verification of metering and other equipment allows for compliance with regulatory standards and accurate measurements of system performance. Planned maintenance optimizes the life span and performance of many assets, and protects the system from the effects of premature failure. Repairing assets enables the ongoing safe and reliable operation of the system.

The selection of planned sustaining OM&A investments is guided by the asset risk assessment process described in Exhibit A, Tab 17, Schedule 7. This process takes into account the condition, age, performance, criticality and utilization of specific assets. An economic evaluation is also performed as part of the process. At times, the economic evaluation may determine that it is more cost-effective to replace an asset rather than to continue to repair or maintain it. These capital replacement activities are described in Exhibit D1, Tab 3, Schedule 2. A summary of the asset risk assessment results is provided in Exhibit D1, Tab 2, Schedule 1.

Demand OM&A work requires an immediate or timely response to customer, safety and system needs. This work includes responding to service interruptions, resolving public safety hazards, replacing or repairing failed equipment, responding to customer requests and providing underground cable locating services. Due to the variable nature of demand work, Hydro One Distribution develops investment levels based on forecast volumes and costs using observed historical averages. Adjustments to this forecast are made based on the projected impact of any changes to the distribution system or to the planned investment programs.

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 17, Schedules 1 to 5, respectively, has been completed for all planned and demand Sustaining OM&A investments in the five test years to ensure that assets are managed prudently so as to meet customer, operational and regulatory requirements. The test year expenditures for Sustaining OM&A along with the historical and bridge spending are provided in Table 1 below.

Table 1
Sustaining OM&A
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Stations	27.2	25.8	26.4	22.3	27.9	27.6	28.4	28.9	28.6	28.3
Lines	124.4	137.4	130.9	148.1	134.0	141.3	149.7	152.4	154.6	157.5
Meters, Telecom, & Control	24.1	26.6	14.2	14.2	19.4	18.5	18.7	18.5	18.9	19.4
Vegetation Management	130.2	127.3	136.4	133.5	139.1	142.0	177.6	180.3	161.1	152.9
Total	**305.9**	**317.1**	**307.9**	**318.1**	**320.4**	**329.5**	**374.4**	**380.1**	**363.2**	**358.1**

The increase in overall spending in the test years relative to historical expenditures is largely attributed to the following:

- An increase in the Lines and Station OM&A expenditures for PCB testing of oil filled equipment to meet requirements set out by Environment Canada regulations;

- An increase in the Meter, Telecom, and Control OM&A expenditures for meter verifications to meet requirements set out by Measurement Canada regulations; and
- An increase in the Vegetation Management OM&A expenditures to address a backlog in the vegetation management program that will help manage costs in the long term and improve reliability.

Additional details concerning these increases and a discussion of year over year variations in spending, where significant, are discussed in more detail below.

3.0 STATIONS

Hydro One Distribution owns and operates 1,004 distribution and regulating stations province-wide. Distribution stations are used to lower voltages for more localized delivery of power while regulating stations are used to maintain voltages when feeders are long and customer density is low. Station facilities typically contain the following components: transformers, instrument devices, fuses, reclosers, disconnect switches, bus, insulators, support structures, power cables, cable terminators, surge arresters, station service supplies, grounding systems, fences, and buildings. Hydro One Distribution also owns and maintains a fleet of 28 mobile unit substations that are used to provide emergency backup following a failure, and to facilitate planned maintenance and capital replacement activities at distribution and regulating stations to reduce power interruptions.

Stations Sustaining OM&A funding covers investments required to maintain existing assets located within distribution and regulating stations, as well as to maintain the 28 mobile unit substations. Hydro One Distribution manages its Stations Sustaining OM&A program by dividing the program into three categories:

1. Stations Demand and Corrective Maintenance, which funds the OM&A investments to respond to emergency failures at distribution and regulating stations;
2. Planned Station Maintenance, which funds the OM&A investments to reduce the risk of equipment failure at distribution and regulating stations; and
3. Land Assessment and Remediation, which funds the OM&A investments to test and carry out remedial work to manage the contaminated soil at distribution and regulating stations.

Required funding for the test years 2015 to 2019, along with the spending levels for the bridge and historical years are provided in Table 2 for each category.

Table 2
Stations Sustaining OM&A
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Stations Demand and Corrective Maintenance	8.4	8.2	9.2	7.7	9.2	9.4	10.0	10.2	10.3	10.5
Planned Station Maintenance	13.0	12.8	11.6	9.1	12.2	12.5	12.2	12.4	12.7	12.4
Land Assessment and Remediation	5.8	4.8	5.5	5.5	6.5	5.7	6.2	6.3	5.7	5.5
Total	**27.2**	**25.8**	**26.4**	**22.3**	**27.9**	**27.6**	**28.4**	**28.9**	**28.6**	**28.3**

The overall Stations Sustaining OM&A expenditures for the test year 2015 is in line with the 2014 bridge year and continues to remain relatively constant over the five year period.

3.1 Stations Demand and Corrective Maintenance

3.1.1 Introduction

Demand maintenance refers to the repair activities that are undertaken when station components fail. The consequence of a station component failure is typically a service interruption to customers. These station interruptions can impact up to 10,000 customers per occurrence. Corrective maintenance refers to the repair of deficiencies that are identified through preventive maintenance and trouble calls. Station demand and corrective maintenance work must be carried out in a timely manner in order to minimize the risks to customer reliability and safety.

3.1.2 Investment Plan

The Stations Demand and Corrective Maintenance program covers the OM&A component of emergency work required to:

- respond to component failures at distribution and regulating stations,
- correct situations where there is a likelihood of failure that could cause a power interruption or present a safety hazard,
- complete high priority corrective work discovered during planned maintenance activities that cannot be deferred until the next planned maintenance, and
- address security issues (i.e. copper theft) that pose safety risks to the public as well as Hydro One Distribution personnel.

In most cases, smaller components such as insulators, connectors, switches, etc. will be repaired, temporarily bypassed, or replaced on site. The failure of a large component, such as a transformer, may require moving the equipment off site and repairing it at a central location or replacing it. If a prolonged service interruption is anticipated, service is typically restored through the temporary use of a mobile unit substation.

The station demand and corrective maintenance program also includes the corrective maintenance requirements for the strategic spare inventory including: leak repair on transformers, underload tap changer testing and repair, transformer painting and cleaning and repair of the cabinet that houses all of the control equipment for the transformer control compartment; to ensure the equipment is in operable condition for deployment into service in case of a failure.

When the resolution of the emergency work involves the repair of a component, such work is charged to this program. If the resolution involves the replacement of damaged or defective equipment, this replacement is typically charged to the Sustaining Capital program discussed in Exhibit D1, Tab 3, Schedule 2.

3.1.3 Summary of Expenditures

The planned expenditure for 2015 is $9.4 million with the proposed spending increasing over the five year period on average by 3% annually. The proposed spending in the test years is based on historical spending with adjustments to incorporate recent trending, such as the declining condition of the transformer fleet.

3.2 Planned Station Maintenance

3.2.1 Introduction

The Planned Station Maintenance program is required to reduce the risk of equipment failure, which can impact service reliability to the large number of customers supplied from a distribution station. Planned station maintenance is also critical to minimizing life cycle costs and limiting the amount of unplanned corrective maintenance and capital replacement in future years.

3.2.2 Investment Plan

The planned station maintenance program is divided into three categories: power equipment maintenance, grounds and site maintenance, and PCB testing and retro-filling.

Table 3
Planned Station Maintenance
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Power Equipment Maintenance	11.9	11.3	9.7	7.2	9.4	9.6	9.8	10.0	10.2	9.9
Grounds and Site Maintenance	0.9	1.4	1.8	1.9	2.3	2.4	1.9	1.9	2.0	2.0
PCB Testing and Retro-filling	0.2	0.1	0.1	0.1	0.5	0.5	0.5	0.5	0.5	0.5
Total	**13.0**	**12.8**	**11.6**	**9.1**	**12.2**	**12.5**	**12.2**	**12.4**	**12.7**	**12.4**

Power Equipment Maintenance

The power equipment maintenance program includes station inspections and planned maintenance of the power equipment, strategic spares, and mobile unit substations.

- Station inspections are required by Appendix C – Minimum Inspection Requirements of the Distribution System Code. The inspections are undertaken to identify obvious structural problems, safety hazards, equipment defects and signs of vandalism prior to initiating planned maintenance work. Hydro One Distribution’s stations are inspected two times per year.

- Planned maintenance of power equipment includes condition-based maintenance on reclosers, transformers and underload tap changers. Maintenance for reclosers is based on the number of operations as suggested by the manufacturer; whereas maintenance for transformers and tap changers is largely based on the analysis of the insulating oil and diagnostic tests.

- Planned maintenance of strategic spares includes inspection and maintenance of spare distribution transformers in order to ensure reliable, deployable spare units. The strategic spares are critical to support the transformer replacements required under demand circumstances.

- Planned maintenance of mobile unit substations is required to ensure these assets are available in good working condition when required. The fleet of 28 mobile unit substations play a key role in providing reliable service to Hydro One Distribution's customers as they provide emergency backup, should a distribution station fail, and facilitate planned maintenance programs at distribution stations. The mobile unit substations also provide load relief during heavy load periods in the summer or winter.

Grounds and Site Maintenance

The grounds and site maintenance program includes weed control, grass cutting, fence repair, access road maintenance, site drainage, foundation repairs and inspections. Inspections are required to verify that all fire extinguishers are in working order on a monthly basis, as per the *Ontario Fire Protection and Prevention Act*. Inspections of the spill containment systems are also required on a quarterly basis as stipulated by the Ministry of Environment.

PCB Testing and Retro-filling

The PCB testing and retro-filling program includes testing of the oil filled power equipment and eliminating Polychlorinated Biphenyl ("PCB") contaminated oil by retro-filling the equipment. Hydro One Distribution is required to eliminate all insulating oil in station equipment with PCB contamination levels above 500 ppm by year end 2014, in accordance with Environment Canada regulations. Hydro One Distribution has applied for an extension, requesting that the 2014 deadline be extended to 2025. Also, according to the regulations, any contamination equal to and above 50 ppm must be removed by 2025. PCB tests on transformer bushings within a station is a very time consuming process that requires a planned transformer outage and the usage of a mobile unit substation to mitigate customer power interruptions in order to obtain the oil sample required for lab testing. Hydro One Distribution will endeavour to test all outstanding station equipment by 2024, assuming the extension is granted. If the extension is not granted, Hydro One Distribution would be required to test all outstanding station equipment by year end 2014. This would result in a significant increase in the spending requirement and would require deferral of all capital work while resources are redirected to complete PCB oil sampling.

3.2.3 Summary of Expenditures

The planned expenditure for station maintenance in 2015 is $12.5 million with an average proposed spending of approximately $12.4 million annually over the five year period. The planned expenditures are in line with the average historical spending.

3.3 Land Assessment and Remediation

3.3.1 Introduction

Soil contamination has occurred over time within some of the distribution station properties as a result of application of certain long lasting chemicals; such as wood preservatives and arsenic-based herbicides; storage and use of mineral insulating oil, fuel, PCBs, and miscellaneous other materials. The historical use and storage of these materials and chemicals met all applicable environment regulations and guidelines at the time they were first used; however, environmental regulations have changed. This has resulted in Hydro One Distribution now having properties which do not meet the new regulatory requirements.

3.3.2 Investment Plan

There are a number of distribution stations properties that have some level of on-site soil contamination, exceeding applicable Ministry of Environment land-use criterion. Because contaminated properties have the potential to cause adverse effects on human health and the environment, Hydro One Distribution has undertaken to assess its properties and carry out remedial work where environmental risks are significant.

The primary focus of the Land Assessment and Remediation program is to reduce the human and ecological risk of off-property impacts. This is achieved by either the implementation of remedial measures to treat, remove or otherwise manage the contamination found off-site or the implementation of on-site management controls to mitigate future off-property impacts.

The Land Assessment and Remediation program consists of sample testing to determine contamination levels, installation of monitoring wells, capping sites in order to stop off-site contamination and site remediation.

3.3.3 Summary of Expenditures

The planned expenditure for 2015 is $5.7 million with an average proposed spending of approximately $5.9 million annually over the five year period. The variations in remediation spending year-over-year, is due to the complexity and volume of work needed to address the particular sites being assessed and remediated. The planned expenditures are in line with average historical spending.

4.0 LINES

Distribution lines total approximately 120,000 circuit kilometres province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way that Hydro One Distribution can legally access and occupy. Line components include poles, conductor, insulators, transformers, switches, fuses, surge arresters, voltage regulators, reclosers, capacitors, and grounding devices.

Lines Sustaining OM&A expenditures are required to maintain the integrity of the distribution lines system. Hydro One Distribution manages its Lines Sustaining OM&A program by dividing the program into four categories:

1. Demand Work, which funds the OM&A investments to respond to trouble calls, locate underground cables and connect and reconnect customers on request;

2. Line Maintenance, which funds the OM&A investments to maintain distribution line equipment and patrol the distribution system;
3. PCB Equipment and Waste Management, which funds the OM&A investments to inspect and test equipment for PCB contamination and to manage both PCB and non-PCB waste; and
4. Other Services, which funds the OM&A investments to respond to customer inquiries, rent idle transmission lines, track service quality indicators, fund specific community events, and complete joint use audits.

Required funding for the test years 2015 to 2019, along with the spending levels for the bridge and historical years are provided in Table 4 for each category.

Table 4

Lines Sustaining OM&A ($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Demand Work	80.6	100.9	96.8	107.9	95.9	92.4	93.2	94.7	95.6	97.4
Line Maintenance	29.0	23.4	18.7	21.1	16.8	23.5	23.9	24.4	24.9	25.4
PCB Equipment and Waste Management	4.9	4.0	5.0	5.1	7.4	11.3	18.3	18.7	19.1	19.4
Other Services	9.8	9.1	10.4	14.0	13.8	14.1	14.3	14.7	15.0	15.3
Total	**124.4**	**137.4**	**130.9**	**148.1**	**134.0**	**141.3**	**149.7**	**152.4**	**154.6**	**157.5**

The overall Lines Sustaining OM&A expenditures for the test year 2015 are approximately 5% greater than the 2014 bridge year. The Lines OM&A expenditures continue to grow on average 3% annually over the five year period. The primary driver for the OM&A increase is the PCB inspection and testing requirements of oil-filled line equipment set out by Environment Canada regulations as referred to on page 19 of this exhibit.

4.1 Demand Work: Trouble Calls, Underground Cable Locates, Disconnects/Reconnects

4.1.1 Introduction

The demand work programs (Trouble Calls, Underground Cable Locates, and Disconnects/Reconnects) are required to respond to customer service interruptions, power quality concerns, and customer-driven service responses.

4.1.2 Investment Plan

This demand work program is divided into three categories, as described below. The externally driven nature of this work requires Hydro One Distribution to forecast costs based on historical averages, with adjustments made to reflect anticipated changes in expenditure patterns or work requirements.

Table 5
Demand Work
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Trouble Calls	57.8	76.3	65.5	76.0	67.9	64.8	65.9	67.7	69.0	70.0
Underground Cable Locates	13.9	15.5	22.0	22.0	18.5	17.9	17.4	16.9	16.3	16.8
Disconnects/Reconnects	8.9	9.1	9.3	9.9	9.5	9.7	9.9	10.1	10.3	10.5
Total	**80.6**	**100.9**	**96.8**	**107.9**	**95.9**	**92.4**	**93.2**	**94.7**	**95.6**	**97.4**

Trouble Calls

Trouble Calls typically involve the restoration of service to customers impacted by an unplanned power interruption. Unplanned power interruptions on the distribution system are largely due to line component failures or contact with right-of-way vegetation caused by severe weather conditions. Depending on the specific circumstances, these interruptions can vary in size, from impacting single customers for brief periods of time to impacting thousands of customers for several hours. Trouble calls may also be used to respond to customer complaints or to correct defects on the distribution system that present a safety concern or could result in an imminent service interruption.

When the resolution of a trouble call involves the repair of an affected component or the clearing of fallen vegetation, such work is charged to this program. If the resolution involves the replacement of damaged or defective equipment, this replacement is charged to the Sustaining Capital program discussed in Exhibit D1, Tab 3, Schedule 2.

Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements, to correct known hazards and to maintain reliable service in accordance with good utility practice. Hydro One Distribution's performance in responding to trouble calls is reflected by service quality indicators specified in the OEB's Distribution System Code, Section 7, and in the Electricity Distribution Rate Handbook, Sections 15.2.1 and 15.2.3.

The trouble call program is reactive in nature and as such its volume of work varies based on a number of external factors. These factors include weather, equipment failure, and the volume of customer power quality complaints. The proposed spending for the test years is forecasted based on an expected volume of 45,000 calls per year.

Underground Cable Locates

The Underground Cable Locates program provides the service of locating and marking Hydro One Distribution underground plant for customers and contractors who request this information. This service is provided in accordance with the Electrical Safety

Authority's "Guidelines for Excavating in the Vicinity of Distribution Lines" and is intended to minimize utility equipment damage while providing worker safety to those excavating in proximity to buried utility plant. In order to encourage the use of this service, the program costs are not recovered through end user charges. This approach is consistent with the practice followed by other regulated utilities, including cable TV, telephone service and natural gas utilities.

This program is driven by external demand for underground cable locates. Hydro One Distribution has seen an increasing number of requests, attributed to a continued emphasis on the "call before you dig" program. This increased emphasis is intended to reduce the number of "dig in" events that can have worker safety risks and impact service reliability. The proposed spending for the test years is based on a forecast of 170,000 locate requests per year.

Service Disconnects and Reconnects

The Service Disconnects and Reconnects program responds to customer requests for isolation of customer owned assets from the distribution system. This isolation may be requested by the customer to allow for safe conditions to facilitate working on customer owned equipment. This service is provided to each customer once per year at no cost, as specified in Hydro One Distribution's Conditions of Service, in order to encourage customers to maintain their facilities and to work safely.

The number of service disconnections and reconnections requests have been increasing over the past several years. The proposed spending for the test years is based on a forecast of 13,300 disconnect and reconnect requests per year.

4.1.3 Summary of Expenditures

The planned expenditure for demand work in 2015 is $92.4 million with the proposed spending increasing over the five year period on average by 1% annually. Since these programs are demand driven, costs vary from year over year. The planned expenditures are in line with the average historical spending.

4.2 Line Maintenance

4.2.1 Introduction

The line maintenance program is required to provide ongoing preventive and corrective maintenance on line assets. This maintenance may include the repair or replacement of minor equipment components. This program also includes line patrols used to identify defects and collect asset information which is a key component in the assessment of line assets.

4.2.2 Investment Plan

The line maintenance program is divided into three categories, as described in Table 6.

Table 6
Line Maintenance
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Preventive and Corrective Maintenance	14.2	13.5	9.1	10.5	10.2	16.7	17.0	17.3	17.7	18.0
Line Patrols	14.0	9.0	8.7	9.9	5.6	5.7	5.9	6.0	6.1	6.2
Sentinel Lights	0.8	0.9	0.9	0.8	1.0	1.0	1.1	1.1	1.1	1.1
Total	**29.0**	**23.4**	**18.7**	**21.1**	**16.8**	**23.5**	**23.9**	**24.4**	**24.9**	**25.4**

Preventive and Corrective Maintenance

Hydro One Distribution's preventive maintenance of line equipment is undertaken on a planned basis and includes maintenance on line reclosers, regulators, insulators, and three-phase air break and load break switches. There are approximately 12,000 reclosers, 2,300 line regulators, and 2,600 three phase switches in the distribution lines system.

Hydro One Distribution's corrective line maintenance activities are focused on the repair and replacement of minor defective components. These may include broken guy wires, damaged insulators, and faulty lightning arresters. Defects typically occur due to normal deterioration brought on by age and component usage, but in some cases system wide problems with particular components also drive corrective action. All defects are identified and logged during line patrols. The defects are categorized based on the requirements of the Distribution System Code and corrected in an appropriate time frame. Where possible, defects corrections are combined with other work to improve operational efficiency. The proposed spending for the test years is based on a forecast of approximately 20,000 defect corrections per year.

Line Patrols

The patrol of distribution lines is required by Appendix C – Minimum Inspection Requirements of the Distribution System Code. These line patrols are undertaken to identify public safety hazards, damaged equipment, or any other defects that may impact the safe and reliable operation of the distribution system. Line patrols are also a key component in the assessment of condition of distribution assets. Hydro One Distribution patrols one-sixth of all rural feeders and one-third of all urban feeders each year to identify defects for corrective action. Identified defects requiring immediate attention are corrected under the trouble call programs as discussed in Section 4.1 of this Schedule and Section 4.1 of Exhibit D1, Tab 3, Schedule 2. Less serious defects are addressed on a planned basis. This approach meets the requirements of the Distribution System Code.

Overhead, underground, and submarine assets are all inspected during a distribution line patrol. While these inspections are typically visual in nature, other techniques, including sounding and boring test for poles and time domain reflectometry tests for submarine cables, are employed when necessary.

Sentinel Lights

The sentinel light program provides outdoor lighting for rural customers and has been in existence in Ontario for over 20 years. Hydro One Distribution has a contractual obligation to honour commitments made by the former Ontario Hydro for existing installations, but no longer accepts requests for new sentinel light installations.

There are currently approximately 31,000 sentinel lights managed by Hydro One Distribution, generating approximately 2,000 maintenance responses per year.

4.2.3 Summary of Expenditures

The planned expenditure for line maintenance in 2015 is $23.5 million, with the proposed spending increasing over the five year period on average by 2% annually. The preventive and corrective maintenance program is forecasted to exceed its historical spending levels due to increased efforts to remove defects from the distribution system. However, improvements to the distribution patrol program are expected to have an offsetting effect.

4.3 PCB Equipment and Waste Management

4.3.1 Introduction

The PCB Equipment and Waste Management program includes the inspection and testing of line equipment potentially contaminated with PCBs, along with the management of waste generated during the course of maintaining distribution assets. These activities ensure that Hydro One Distribution operates in an environmentally responsible manner and in compliance with applicable regulations.

4.3.2 Investment Plan

This program is divided into two categories, as described in Table 7.

Table 7
PCB Equipment and Waste Management
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
PCB Lines Equipment Inspection and Testing	1.0	0	0	0.0	2.2	6.0	12.9	13.2	13.4	13.7
Waste Management	3.9	4.0	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7
Total	**4.9**	**4.0**	**5.0**	**5.1**	**7.4**	**11.3**	**18.3**	**18.7**	**19.1**	**19.4**

PCB Lines Equipment Inspection and Testing

This program includes the inspection and testing of oil filled distribution line equipment to determine their PCB contamination level. Equipment manufactured prior to 1985 may contain insulating oil contaminated with PCBs. Environment Canada has issued regulations that require the removal of pad mounted equipment with insulating oil that contains PCB contamination levels above 500 ppm by 2009 and the removal of all pole mounted line equipment with insulating oil that contains PCB contamination levels above 50 ppm by 2025.

Hydro One Distribution initially focused on the inspection and testing of pad-mounted transformers. Testing of these transformers was completed in 2010. Beginning in 2014, pole mounted line equipment will be inspected and tested. From past experience with PCB testing, Hydro One Distribution projects that approximately 8% of all transformers will exceed the 50 ppm threshold and will need to be retired as part of the Lines PCB

Equipment Replacements Program discussed in Section 4.3 of Exhibit D1, Tab 3, Schedule 2. In order to satisfy the PCB regulations by 2025, Hydro One Distribution will perform approximately 44,000 inspections and approximately 26,000 tests annually.

Waste Management

Once transformers and other distribution equipment are removed from service, there is a requirement to manage the resulting solid and liquid waste materials in an environmentally approved manner.

This management includes reporting of PCB inventories to regulatory authorities, disposal and destruction of these inventories, disposal of non-contaminated oils, and management and disposal of other wastes.

4.3.3 Summary of Expenditures

The planned expenditure for 2015 is $11.3 million with an increase to $18.3 million in 2016. The proposed spending continues to increase over the 2017 to 2019 period by 2% annually. This represents an increase over the historical spending which is required to address the PCB regulations set out by Environment Canada.

Reduced funding would result in the deferral of a large amount of PCB inspection and testing work until closer to the 2025 deadline and would require even larger annual expenditures in later years, along with significant labour resources to meet the requirements. It would also impact Hydro One Distribution’s environmental stewardship commitment for responsible waste management and hamper the ability to comply with waste management regulations.

4.4 Other Services

4.4.1 Introduction

The Other Services program is required to address a number of miscellaneous services, including response to customer inquiries, idle transmission line rental, tracking of service quality indicators, funding of specific community events, and completing joint use audits.

4.4.2 Investment Plan

The Other Services program is divided into four categories as described in Table 8.

Table 8
Other Services
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer Inquiries	5.2	5.4	6.4	7.8	5.5	5.6	5.6	5.8	5.9	6.0
Investigations & Data Collection	1.5	0.9	1.0	1.4	2.0	2.0	2.0	2.1	2.1	2.2
Miscellaneous Services	3.1	2.8	3.0	2.5	2.5	2.5	2.6	2.6	2.7	2.7
Transmission Idle Line Rental	-	-	-	2.3	3.9	4.0	4.1	4.2	4.3	4.3
Total	**9.8**	**9.1**	**10.4**	**14.0**	**13.8**	**14.1**	**14.3**	**14.7**	**15.0**	**15.3**

Customer Inquiries

This program includes the work required to respond to inquiries concerning customer services, bills, location of Hydro One Distribution assets on customer properties, planned and unplanned outages, power quality complaints, and clarifications on policies. The number of inquiries can vary from one year to the next. The proposed spending forecast is based on the historic volume of approximately 8,000 inquiries per year.

Investigations and Data Collection

This program includes the work required to respond to requests for detailed information on distribution station and line assets. It addresses information requirements related to specific requests for the condition of selected assets, public and employee safety hazards, unacceptable system performance, and audits of joint use facilities and data required to support responses to customer reliability concerns.

Miscellaneous Services

This program includes a number of activities; pole rental payments to Local Distribution Companies (“LDCs”) where Hydro One Distribution wires are supported by these poles, LDC switching requests, collection and reporting service quality indicators to the Ontario Energy Board on an annual basis, and miscellaneous engineering and environmental support.

Transmission Idle Lines Rental

This expenditure is for the annual rental payments to Hydro One Transmission for Hydro One Distribution’s use of transmission facilities to supply power to customers at distribution voltages.

4.4.3 Summary of Expenditures

The planned expenditure for 2015 is $14.1 million with the proposed spending increases over the five year period on average by 2% annually. The majority of these expenditures are ‘demand’ driven and are based on historic customer demands and forecast workload. These planned expenditures are greater than the historic average spending as a result of the addition of the Transmission Idle Line Rental commitments.

5.0 METERING

Hydro One Distribution currently owns and maintains revenue meters of two main types: Retail Revenue Meters and Wholesale Revenue Meters. The retail revenue meters are used to measure energy consumption for retail customers. Whereas the wholesale revenue meters are used to settle the purchase of energy where the point of supply is directly connected to the IESO-controlled grid.

Metering Sustaining OM&A expenditures are required to operate and maintain the existing metering assets. Hydro One Distribution manages its Metering Sustaining OM&A program by dividing the program into three categories:

1. Retail Revenue Meters, which funds the OM&A investments to perform routine and corrective maintenance;
2. Wholesale Revenue Meters, which funds the OM&A investments to perform routine and corrective maintenance, and to support IESO registration or inspection processes; and
3. Telecom, Monitoring & Control, which funds the OM&A investments to enable collection of energy consumption data, and to control and operate sectionalizing switches and electronic reclosers installed on distribution system.

Required funding for the test years 2015 to 2019, along with spending levels for the bridge and historic years are provided in Table 9 for each category.

Table 9
Metering Sustaining OM&A
($ Millions)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Revenue Meters*	21.7	22.1	9.1	9.1	13.6	12.6	12.7	12.3	12.6	13.0
Wholesale Revenue Meters	1.3	1.8	1.8	2.0	2.3	2.4	2.4	2.5	2.6	2.6
Telecom, Monitoring and Control	1.1	2.7	3.3	3.1	3.5	3.5	3.6	3.7	3.7	3.8
Total	**24.1**	**26.6**	**14.2**	**14.2**	**19.4**	**18.5**	**18.7**	**18.5**	**18.9**	**19.4**

* Includes the OM&A expenditures associated with the implementation of the Smart Meter project for historical years 2010 and 2011 in the amount of $14.5 million and $15.4 million respectively.

The overall Metering Sustaining OM&A expenditures for the test year 2015 is in line with the 2014 bridge year and continues to remain relatively constant over the five year period.

5.1 Retail Revenue Meters

5.1.1 Introduction

There are three types of retail revenue meters utilized on the Hydro One distribution system based on average monthly demand. The types include:

- Approximately 1.2 million smart meters measuring energy consumption for residential and other customers whose average monthly demand is 50 kW or less under the Time of Use ("TOU") pricing scheme;
- About 7,300 electronic demand meters for small business customers with an average

monthly electricity demand greater than 50 kW; and

- About 1,300 interval meters for existing business customers whose demand exceeds 1,000 kW, recently connected customers whose demand exceeds 200 kW and customers below the threshold who have requested interval meters.
-

Retail revenue meters are required to be operated, maintained and verified in accordance with requirements of the *Electricity and Gas Inspection Act*, Measurement Canada, and the market rules.

5.1.2 Investment Plan

The retail revenue meter program is required to carry out meter sampling, which includes verification of the accuracy by an accredited meter verifier. The program also addresses the replacement of faulty meters and other components (such as elements of the communication network which support the meters).

Based on recent operational experience approximately 18,000 out of the existing 1.2 million retail meters are required to be removed and replaced each year due to random failures, damage or obsolescence.

Meter verifications are required every 6 or 10 years depending on meter classification, typical residential type meters are on a 10 year frequency. Typical meter verifications involve the testing of a statistically derived sample group of meters, according to a sampling program monitored and regulated by Measurement Canada. If the sample passes, then all meters in that sample group are deemed verified; however, if the sample fails, then all meters in that sample group are required to be replaced. For meters that do not qualify to be sampled, such as commercial or industrial meters, then each meter seal must be individually verified.

Hydro One Distribution has implemented the deployment of smart meters to all residential customers as directed by the Ministry of Energy. Hydro One Distribution continues to examine smart meter options with appropriate communication platforms for its demand and interval-metered customers. If there is a viable smart meter option, Hydro One Distribution will develop and implement smart metering plans for these types of retail revenue meters.

5.1.3 Summary of Expenditures

The planned expenditure for 2015 is $12.6 million with the proposed spending increasing over the five year period on average by 1% annually. The test years proposed spending represents an average increase of 60% over the historical spending, with the exclusion of the 2010 and 2011 Smart Meter project OM&A costs. This increase is a result of meter verification sampling quantities returning to normal levels. Hydro One Distribution received a dispensation from Measurement Canada which allowed meters coming due for verification to remain in place without verification to avoid inefficiencies which would result from verifying meters that were planned for imminent replacement by smart meters. As a result of this dispensation, costs associated with maintaining retail revenue meters have been lower during the years leading up to 2013.

5.2 Wholesale Revenue Meters

5.2.1 Introduction

Since 2003, in accordance with market rules, accountability for legacy wholesale revenue meters (“WRMs”) owned by Hydro One Transmission, but used to settle Hydro One Distribution energy purchases from the IESO-administered market, have been transitioning to Hydro One Distribution ownership. By the end of 2013, Hydro One Distribution has assumed accountability for 387 WRMs.

Wholesale revenue meters are required to be operated, maintained and verified in accordance with the IESO wholesale market rules.

5.2.2 Investment Plan

The wholesale revenue meter program is required to provide preventative and corrective maintenance, meter re-sealing and verification, trouble call response, IESO registration, and routine maintenance as required by the IESO market rules.

Wholesale revenue meters are subject to IESO inspections to verify compliance of metering installations with technical specifications contained in the market rules. Any identified deficiencies must be corrected within the prescribed time limits. In general, wholesale meters are re-verified or re-sealed every 6 years.

As Hydro One Distribution is an IESO-registered meter service provider, it will provide all servicing for its WRMs to ensure accurate wholesale billing by the IESO, and to comply with the market rules and Measurement Canada regulations.

5.2.3 Summary of Expenditures

The planned expenditure for 2015 is $2.4 million with the proposed spending increasing over the five year period on average by 2% annually. The test years proposed spending represents an average increase of 40% over the historical spending. This increase is a result of the gradual increase in the number of WRMs, due to new transformer stations and new wholesale meter points as a result of LDC acquisitions, which Hydro One Distribution has assumed accountability to maintain.

5.3 Telecom, Monitoring and Control

5.3.1 Introduction

A telecommunication link to retail smart meters is required for the remote interrogation of the meters in order to obtain energy consumption data for billing processes. Hydro One Distribution also has telecommunication requirements associated with some sectionalizing switches which remotely control feeders, and provide monitoring and control of some distribution stations from the Distribution Management System (DMS).

5.3.2 Investment Plan

The telecom, monitoring and control program is required to:

- maintain and troubleshoot the telecommunication infrastructure which collects energy consumption data from the retail smart meters, and
- maintain telecommunication infrastructure in order to facilitate the upgrade of demand metered customers with electronic demand meters. Note: Hydro One Distribution is looking to leverage its existing network for these meters to minimize 3rd party telecom charges. However, where this option is not available, telecom leased circuits will be used to provide remote interrogation.

As Hydro One Distribution continues to modernize its distribution network, there will be a need for further telecommunication capability to control the new intelligent devices (such as sectionalizing switches, electronic reclosers, etc.) to provide sufficient network coverage.

5.3.3 Summary of Expenditures

The planned expenditure for 2015 is $3.5 million with the proposed increasing over the five year period on average by 2% annually. The test years proposed represents an average increase of 30% over the historical spending. This increase is a result of the gradual increase in telecommunication requirements resulting from the smart meters and the modernization of the distribution network.

6.0 VEGETATION MANAGEMENT

Hydro One Distribution has approximately 102,000 km of distribution rights-of-way, which traverse three forest regions in the Province of Ontario. The predominant region, the Great Lakes - St. Lawrence forest region, consists of mixed conifer and deciduous forests stretching from the edges of the Great Lakes and the St. Lawrence River west to the Manitoba boarder. The other two regions include the deciduous forests of southwestern Ontario and the boreal forests of northern Ontario.

The vegetation management program manages clearances to energized equipment to maintain an acceptable and sustainable level of reliability, manages safety hazards posed by trees in proximity to energized lines, manages plant species on the right-of-way floor to permit worker access for maintenance and restoration of power, and minimizes environmental, ecological and social impacts.

Hydro One Distribution manages its vegetation management OM&A program through five activities:

1. landowner notification,
2. line clearing,
3. brush control,

4. demand vegetation management, and
5. hazard tree removal

These annual programs are managed using a risk based approach (outlined in Exhibit A, Tab 17, Schedule 7) that considers vegetation condition data, right-of-way age, reliability data, and issues identified by Hydro One Distribution personnel and the general public. Activities are planned to optimize impacts to the distribution system and are audited to ensure continuous improvement.

Required funding for the test years 2015 to 2019, along with the spending levels for the bridge and historical years are provided in Table 10 for each category.

Table 10
Vegetation Management OM&A
($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Landowner Notification	7.5	7.3	7.1	7.3	7.1	7.3	10.1	10.0	8.8	8.8
Line Clearing	79.8	81.5	87.4	84.1	92.3	95.4	117.6	120.3	107.0	99.9
Brush Control	34.8	31.2	34.7	33.9	31.4	31.6	42.8	42.8	38.2	37.0
Demand Vegetation Management	8.1	7.3	7.0	7.9	8.1	7.4	6.8	6.9	6.8	6.9
Hazard Tree Removal	-	-	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**130.2**	**127.3**	**136.4**	**133.5**	**139.1**	**142.0**	**177.6**	**180.3**	**161.1**	**152.9**

The overall Vegetation Management OM&A expenditures for the test year 2015 are approximately 2% greater than the 2014 bridge year. Vegetation Management OM&A continues to grow on average 25% annually over the 2016 and 2017 period. These expenditures allow for a concentrated effort to bring all rights-of-way to an efficient cycle duration of eight years. Unit cost increases reflect the increased tree densities and work complexities resulting from clearing overgrown rights-of-way. By 2018 and 2019, the crest of the backlog wave will have been addressed and Hydro One Distribution will begin to realize the cost benefits of returning feeders on cycle. This is reflected in the declining spending levels for those years.

6.1 Landowner Notification

6.1.1 Introduction

Prior to starting line clearing and brush control, property owners are consulted to review the work plan for their property and to resolve issues concerning tree removal, tree pruning, brush control, property related restrictions and environment concerns.

6.1.2 Investment Plan

The customer notification program includes the consultation process with the property owner, job planning, and the acquiring of approvals from other groups, including Municipalities and the Ministry of Natural Resources, as required. These planning and project management activities are essential for Hydro One Distribution to complete its annual planned vegetation management work programs with minimal disruption, and to manage customer and property owner concerns in a responsible and proactive manner.

6.1.3 Summary of Expenditures

The planned expenditure for 2015 is $7.3 million with the proposed spending increasing over the five year period. The unit costs for landowner notifications remain stable over the period. The increase is a result of a higher volume of landowner notifications required in conjunction with increases in the line clearing and brush control programs over the same period.

6.2 Line Clearing

6.2.1 Introduction

The distribution line clearing program manages the right-of-way edge to meet clearance and reliability expectations, ensure public and employee safety, and minimize environmental, ecological and social impacts.

6.2.2 Investment Plan

The line clearing program manages vegetation along the right-of-way edge by:

1) Removing damaged or diseased trees that pose a threat of falling into a line; and
2) Pruning trees to maintain clearances to energized facilities.

As outlined in Exhibit D1, Tab 2, Schedule 1, Hydro One Distribution has approximately 23% of right-of-way kilometers beyond the 8-year cycle target. In order to improve the reliability of the distribution system under both normal conditions and during storm events, Hydro One Distribution is proposing a short term increase in the line clearing work program in 2016 and 2017 to 14,250 km annually. After these two years, the line clearing work program will return to 12,750 km annually, which will sustain the 8-year cycle target. By 2019 program costs will better align with historical spending and reflect the reliability and life-cycle cost benefits of maintaining the system on the 8-year cycle targets.

6.2.3 Summary of Expenditures

The planned expenditure for 2015 is $95.4 million with proposed spending increasing over the five year period. The increase in spending represents a five year plan to bring all rights-of-way to an efficient 8-year line clearing cycle.

6.3 Brush Control

6.3.1 Introduction

The brush control program manages the vegetation on the right-of-way floor to minimize the presence of trees that can grow tall enough to contact the overhead lines and prevent access to our assets.

6.3.2 Investment Plan

Hydro One Distribution uses an Integrated Pest Management approach to the brush control program. This approach is a provincially mandated pest management approach that uses an adaptive strategy to managing non-compatible plant species on the rights-of-way. The approach uses a combination of mechanical, chemical and motor manual methods. Through effective management of non-compatible vegetation, Hydro One Distribution is able to facilitate access to equipment for inspection and maintenance activities as well as emergency response. As brush control is performed in conjunction with line clearing, the proposed spending for the test years is forecasted based on the same accomplishment levels as the line clearing program.

6.3.3 Summary of Expenditures

The planned expenditure for 2015 is $31.6 million with the proposed spending increasing over the five year period. Mirroring the line clearing program, the brush control program has increased spending through 2017 to address the maintenance backlog. After older, overgrown feeders have been cleared, the 2018 program and beyond will focus on sustaining and managing compatible vegetation on the right-of-way floor. Therefore program expenditures will stabilize and keep pace with the rate of vegetation growth.

6.4 Demand Vegetation Management

6.4.1 Introduction

All of the 102,000 km of rights-of-way are situated in the public domain and the management of vegetation on and adjacent to these rights-of-way is of interest to many of Hydro One Distribution customers, property owners, municipalities, and government ministries. Each year these groups identify emergent vegetation issues that are addressed outside of the planned programs described above. This is a critical component of the vegetation risk management to ensure customer reliability and public safety.

6.4.2 Investment Plan

Demand vegetation management work initiated by the public includes the removal of trees that may fall into a line, restoring clearances to energized equipment and removing healthy trees as required by property owners at locations that are not within the current year's planned program.

In addition to issues raised by external stakeholders, a number of the reliability and safety issues are identified by Hydro One Distribution personnel each year. These issues may be identified through line patrol observations, routine trouble call response, or reliability monitoring. Once identified, issues are addressed in an off-cycle manner.

6.4.3 Summary of Expenditures

The planned expenditure for 2015 is $7.4 million with the proposed spending decreasing in 2016, before stabilizing over the remainder of the period. This decrease reflects the relationship between the expected success of the planned line clearing and brush control programs reducing the volume of demand vegetation management activities.

6.5 Hazard Tree Removal

6.5.1 Introduction

The hazard tree removal program is a new mid-cycle maintenance program that targets emergent hazard trees on high priority distribution feeder sections.

6.5.2 Investment Plan

Industry benchmarking has identified a hazard tree removal program as a best practice management approach for mitigating the risk of trees falling onto assets. This new program to the vegetation management portfolio is employed to mitigate some of the risks associated with having a longer than average maintenance cycle. The objective of the hazard tree removal program is to decrease asset liability and reduce tree related outages on high priority line sections outside of our regular line clearing program.

6.5.3 Summary of Expenditures

The planned expenditure for 2015 is $0.3 million with the proposed spending remaining constant over the five year period. As a new program, spending for the hazard tree program is relatively small compared to other programs. The program is being rolled out gradually to allow the concept to be operationally proven and to allow for efficient processes to be established.

DEVELOPMENT OM&A

1.0 INTRODUCTION

Development OM&A expenditures are required to ensure safe, reliable and efficient operation and development of the distribution system. Data collection and analysis activities are undertaken that ensure existing and forecast customer load and generation demands are met, to maintain distribution system reliability and to ensure the impact of distributed generation that is connected to the system are effectively monitored. These expenditures also ensure that standards are in place to meet distribution construction and planning needs, as well as legal and regulatory requirements.

2.0 DEVELOPMENT OM&A SUMMARY

Development OM&A expenditures are broken down into four main functional areas:
(1) Data Collection, Engineering and Technical Studies;
(2) Distributed Generation Connections;
(3) Standards & Technology; and
(4) Smart Grid Studies.

Data Collection, Engineering and Technical Studies include activities such as collection and analysis of loading information, feeder balancing, protection review studies, short circuit studies and power quality investigations that are required to support investment decisions.

Distributed Generation Connection studies are undertaken to evaluate the impact of connecting new or modified generation projects to the Hydro One distribution system as per the requirements of the Distribution System Code (“DSC”). Expenditures in this area include program oversight costs, monitoring connection process effectiveness and monitoring and managing impacts of Distributed Generation connections on the distribution system.

The Standards and Technology function covers the development of new and the review of existing technical distribution standards. These are undertaken in response to internal business requirements as well as compliance requirements set by authorities outside Hydro One Distribution, such as the Electrical Safety Authority (“ESA”). The technology portion of the program encompasses research and development projects.

The Smart Grid Studies function is a critical component of Hydro One’s Smart Grid Deployment Plan. This provides research to support grid modernization activities such as the safe and reliable integration of distributed generators, energy storage and electric vehicles into the distribution system and to address issues that arise in the Smart Grid Program.

The funding for 2015 through 2019, along with the spending levels for the bridge and historic years are provided in Table 1.

Table 1
Summary of Development OM&A
($ Million)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Data Collection, Engineering and Technical Studies	6.6	4.2	3.9	4.7	4.7	4.7	4.7	4.7	4.9	5.0
Distribution Generation Connections [1]	0.0	2.8	2.9	1.3	2.0	2.2	2.0	2.0	2.0	2.1
Standards and Technology	5.4	6.1	4.2	4.4	5.6	5.6	5.8	6.0	6.1	6.3
Smart Grid Studies[2]	0.3	2.7	3.7	1.7	6.1	2.9	5.2	4.3	4.3	4.4
TOTAL	**12.3**	**15.8**	**14.7**	**12.1**	**18.4**	**15.4**	**17.7**	**17.0**	**17.3**	**17.8**

The increase in overall spending in the test years relative to historical expenditures is largely attributed to the following:

- Data Collection, Engineering and Technical Studies spending was significantly higher in 2010 as Distribution Generation Connections OM&A expenditures were originally included in this funding. Distribution Generation Connections expenditures have been tracked separately since 2011.
- The combined total of Data Collection, Engineering and Technical Studies and Generation Connections OM&A expenditures in the test years are consistent with historical actuals.

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[1] Distribution Generation connections costs have been tracked in a deferral account as approved in proceeding EB-2009-0096, the planned disposition of this account is outlined in Exhibit F1, Tab 1, Schedule 3.
[2] The costs associated with Smart Grid Studies from January 1, 2010 to December 31, 2012 have been tracked in a deferral account as approved in proceeding EB-2009-0096, the planned disposition of this account is outlined in Exhibit F1, Tab 1, Schedule 3.

- Standards and Technology spending is relatively flat over the test years compared to the bridge and historic years.
- Smart Grid Studies expenditures have ramped up with the industry focus on new technology implementation and expenditure variations in the bridge and test years are largely due to the timing of project studies.

Details on the line items presented in Table 1 are provided in the sections below.

2.1 Data Collection, Engineering and Technical Studies

Activities performed under Data Collection, Engineering and Technical Studies involve the gathering and analysis of system data to identify capability and reinforcement needs. Most of Hydro One's distribution system does not contain real time monitoring equipment. Data is routinely collected through a series of studies and measurements from annual feeder loading surveys to ensure that up-to-date and accurate information on the operating characteristics of the distribution system is available to make investment decisions. This data is used to assess the adequacy of the distribution system to meet system requirements and customer demand, and to identify investments to System Capability Reinforcement for lines and stations to ensure reliable operation of the electrical system. The System Capability Reinforcement investments are detailed in Exhibit D1, Tab 3, Schedule 3.

The distribution system data collected is also used to create models and conduct various studies. These studies include load flow analysis; over-current protection studies; minor impact studies on components of the system; and short circuit studies to facilitate customer connections or upgrades. Load flow analyses and over-current protection studies are conducted on a six-year cycle to ensure that the Hydro One Distribution system is compliant with the DSC and associated supply standards (e.g. voltages maintained within acceptable limits). Furthermore, these studies are effective for minimizing line losses and mitigating safety risks on the system. Minor impact and short circuit studies are performed on an as-needed basis.

Included in this area are expenditures required to sustain and support customized tools which are used to perform various technical studies. The overall Data Collection, Engineering and Technical Study program includes ongoing work that is required to avoid service quality deterioration. The annual expenditures required for this program are $4.7 million for 2015 through 2017; $4.9 million in 2018; and $5.0 million in 2019.

These expenditures are critical to effective management of the distribution system and the assets. If these activities were not performed, there would be a lack of data available on which to base investment decisions, and an inability to properly analyze the needs of the system to meet customer requirements. In addition, there would be an increased risk of electrically overloading system assets, possibly resulting in equipment damage, and allowing system performance to deteriorate. This would lead to higher line losses, declining reliability for customers and service quality degradation (e.g. voltage degradation, increased frequency of outages, and increased outage duration).

2.2 Distributed Generation Connections

Hydro One’s investment plans are based on Ministry of Energy (“MOE”) directives on distributed generation (“DG”) facilities and the Ontario Power Authority (“OPA”) Feed-in Tariff (“FIT”) programs for DGs of different sizes. On May 30, 2013, the MOE issued a directive (http://news.ontario.ca/mei/en/2013/05/ontario-working-with-communities-to-secure-clean-energy-future.html) regarding the OPA’s Small FIT and MicroFIT procurement for small Capacity Allocation Exempt (“CAE”) DGs and micro-embedded DGs, respectively. The first procurement for fall 2013 was announced to be 70 MW of

Small FIT and 30 MW of MicroFIT DGs. Thereafter, the annual CAE and micro-embedded generation procurement for the years 2014 - 2018 is 150 MW and 50 MW, respectively. Combining the new procurements for CAE and micro-embedded projects with the previously contracted projects provides the connection forecast for 2014 – 2019. For the CAR projects, there are no new procurement targets at this time but existing contracted projects will continue to be connected in the 2014 – 2019 period. The connection forecast for all three categories is presented in Table 2.

Table 2
2014-19 Distributed Generation Connections Forecast

Program Type	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Capacity Allocation Required ("CAR") Projects - Greater than 500 kW on 15 kV and above or - Greater than 250 kW on 15 kV and below	39	38	38	14	1	1
Capacity Allocation Exempt ("CAE") Projects - No greater than 500 kW on 15 kV and above or - No greater than 250 kW on 15 kV and below	262	262	262	188	188	188
Micro-embedded Projects - No greater than 10 kW	1600	1400	1200	1000	800	600

The OM&A expenditures include costs associated with field coordination of connections, CAE and CAR Preliminary Cost Estimates, Power Quality ("PQ") Investigation and Monitoring, and System Impact Assessment ("SIA") applications to the Independent Electricity System Operator ("IESO").

The field coordination of connections expenditures are incurred by field staff while completing distribution generation work related to Connection, Expansion and Renewable Enabling Investments ("REI").
The CAR preliminary cost estimates expenditures are associated with producing an itemized estimate for the overall connection of a CAR DG. The itemized estimates identify cost allocations into Connection, Expansion and REI assets.

The CAE preliminary cost estimates expenditures are associated with assessing CAE DG connection applications, performing a Connection Impact Assessment ("CIA") once an application is accepted and providing an itemized preliminary cost estimate based on the CIA.

The PQ Investigation expenditures are related to investigations carried out for selected DGs at the point of connection and along the Hydro One distribution system surrounding the DG. These investigations are completed on a demand basis and include expenditures associated with data collection and analysis.

The PQ Monitoring expenditures are related to ongoing collection and storage of PQ data for all DGs larger than 250 kW. The purpose of the ongoing PQ data collection is to proactively monitor system performance to aid in identifying potential issues and problems early on in order to maintain power quality on the Hydro One distribution system.

The SIA applications expenditures are 100% recoverable and thus Hydro One's net expenditures are $0. Further, there are no SIAs forecast for the test years as there is no procurement announced for DGs greater than 500 kW.

Table 3 shows the breakdown of the Generation Connection OM&A expenditures into the categories described above.

Table 3
Summary of Generation Connection OM&A
($M)

	2014	2015	2016	2017	2018	2019	Total
Coordination of Connections	1.1	1.1	1.2	1.2	1.2	1.2	7.0
CAE Preliminary Cost Estimate	0.2	0.3	0.2	0.1	0.1	0.1	0.8
CAR Preliminary Cost Estimate	0.1	0.1	0.0	0.0	0.0	0.0	0.1
PQ Investigation	0.2	0.2	0.2	0.2	0.2	0.2	1.3
PQ Monitoring	0.5	0.5	0.5	0.5	0.5	0.6	3.1
SIA Applications	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	2.0	2.2	2.0	2.0	2.0	2.1	12.3

Direct Benefits

Consistent with the requirements of Regulation 330/09, a portion of the expenses associated with the connection of renewable generators are allocated to Hydro One ratepayers and a portion of the costs are allocated to all Provincial ratepayers. These allocations are explained in Exhibit F, Tab 1, Schedule 3, Attachment 3.

Table 4 shows the expense allocation between Hydro One ratepayers and Provincial ratepayers for the historic, bridge, and test years.

Table 4
Historic and Forecast OM&A Expense Allocation
($M)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Hydro One Ratepayer	0.0	0.3	0.3	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Provincial Ratepayer	0.0	2.5	2.6	1.2	1.8	1.9	1.8	1.8	1.8	1.9
Total	0.0	2.8	2.9	1.3	2.0	2.2	2.0	2.0	2.0	2.1

2.3 Standards and Technology

The Standards and Technology Program provides funding to develop and maintain Hydro One distribution standards, which are driven by public and worker safety, equipment obsolescence, evolving regulatory requirements, technological advancements and chanes in work methods. Technical standards form a collection of comprehensive references used as templates and productivity tools to efficiently and effectively carry out operating, maintenance, and capital programs. Standards also incorporate company policies and requirements to ensure compliance with regulations such as the Electrical Safety Code. Hydro One Distribution monitors and influences emerging industry standards and requirements for new standards mainly through participation in Canadian Standards Association working groups. The collection of standards includes over 350 planning, design and maintenance specifications, 500 material specifications and 800 standards-related drawings.

Reduced funding would result in the unavailability of necessary standards to meet regulatory requirements, construction and planning needs and to effectively deal with technical issues associated with generation connections. Opportunities to utilize emerging technologies would be missed with the potential for increased longer term costs as a result.

2.4 Smart Grid Standards and Technology

The Smart Grid Studies Program provides necessary and critical support to grid modernization efforts and the integration of renewable and variable generators.

As stated in the Report on Renewed Regulatory Framework for Electricity Distributors and reiterated in the Board's Supplemental Report on Smart Grid, smart grid development and implementation will be a central focus of the effort to incent innovation, given the importance of grid-enhancing advanced technology systems and equipment to network modernization.

The Smart Grid Studies Program supports the larger smart grid initiative. The deployment schedule for the smart grid is integrated with, and relies on, the schedule of activities that comprise the Smart Grid Studies Program. The program is also necessary to address issues that arise when deploying smart grid technologies across the Hydro One Distribution system.

As part of the program, Hydro One Distribution has undertaken multi-year studies with various industry, academic and government partners. These partners include the Canadian Electrical Association, Sustainable Development Technology Canada, Electric Power Research Institute, Electrovaya, Temporal Power, the University of Waterloo, the University of Western, Ryerson University, the Centre of Urban Energy, the Ontario Centres of Excellence and the Ontario Power Authority. The studies being undertaken involve identifying, monitoring, evaluating and validating new grid technologies – including laboratory and field demonstrations – and sharing associated information and findings. These partnership arrangements allow Hydro One Distribution to increase its return on the program expenditures.

The Board concluded in its Supplemental Report on Smart Grid (February 2013) that the objectives set out in the Minister's Directive (November 2010) are aligned with the objectives of the Board's Renewed Regulatory Framework. The Board further outlined guidance and expectations for distributors on implementing the smart grid to meet the three objectives set out in the Minister's Directive, namely, (1) customer control, (2) power system flexibility and (3) adaptive infrastructure.

(1) Enabling Customer Control

This Smart Grid Studies Program will address the objective of customer control by educating customers with demonstration projects such as the Energy Hub Management System, which assists customers with energy conservation and utilities with optimizing their feeder operation.

Hydro One Distribution's power quality studies will further the customer control objective. With the introduction of inverter technology into various industrial, commercial and residential customers' loads and inverter technology with solar and wind renewable generation, there are potential power quality issues, such as harmonics, which can potentially damage customers' and distributors' facilities. Power quality studies will be conducted with university partners.

(2) Improving Power System Flexibility

Hydro One Distribution's planned trials of energy storage systems will improve power system flexibility, which facilitates the integration of distributed renewable generation and complex loads. Hydro One Distribution is investigating the use of energy storage to smooth the variable electrical output of distributed renewable generation through counterpoising absorption or release of electrical energy. Hydro One Distribution is planning a trial application of a 5 MW flywheel in the Tillsonburg area. If the trial is successful, the flywheel will be integrated and controlled by the distribution management system (DMS) at Hydro One's Ontario Grid Control Centre (OGCC). Hydro One Distribution also intends to test a 300 kW lithium-ion battery system.

Microgrids could form with the distributed renewable generation being connected to Hydro One Distribution's grid. Pockets of generation and load could operate independently from the grid and, when needed, reconnect to the grid. This poses possible hazards to worker and public safety as well as customer and utility equipment. To enable the power system's flexibility to safely incorporate distributed renewable generation, Hydro One Distribution intends to study and conduct trials on microgrids and their impact on their host grids. With its partners, Hydro One Distribution also intends to study and test advanced system control devices (Volt/Var Controls) to address specific grid conditions raised by distributed renewable generation and improve overall infrastructure efficiency.

(3) Building Adaptive Infrastructure

Like other distributors, Hydro One Distribution faces challenges in accommodating electric vehicles (EV) on its existing system. Level 2 charging of a single EV can cause electric load almost equivalent to a house. With academic and other research partners, Hydro One Distribution intends to study and prototype control systems that enable EV recharging on distribution feeders without comprising the health of existing infrastructure.

With its smart grid improvements, Hydro One Distribution has developed a wealth of data that it can now use to improve planning and operations. Together with its partners, Hydro One Distribution wants to investigate additional ways it can use this newfound data to capture even greater efficiencies and improve the quality of service it provides its customers.

OPERATIONS OM&A

1.0 INTRODUCTION

The Operations function coordinates and dispatches crews as required, plans for and reacts to system contingencies, schedules and coordinates planned outages, provides customer notifications and monitors and reports on the performance of the distribution electric system. Under the current operating environment, the Control Room at the Ontario Grid Control Centre (OGCC) monitors the distribution system at the Transformer Station for correct voltage levels, power quality, equipment loading, and equipment alarms. Operations OM&A investments are required to support these functions.

Operations OM&A also includes initiatives to support environmental, health and safety activities that are required to meet legal obligations, due diligence and aligns with Hydro One's strategic objectives.

Lastly, Operations OM&A includes funding for Smart Grid initiatives corresponding to the Ontario government's renewable generation and conservation initiatives and addresses their impact on distribution operations.

2.0 DISCUSSION

The Distribution System Operations activities are carried out centrally at the OGCC. The OGCC is a shared facility which allows central operations of the distribution and transmission systems. Back-Up operating facilities are provided at a separate site in the event the OGCC or its computer systems are rendered unavailable. This centralized approach has been in place since 2003 when the Distribution Operations Management Centre (DOMC) was consolidated with Hydro One Transmission's real-time operations.

The cost assigned to Hydro One Distribution for Distribution Operations at the OGCC is based on the "Review of Allocation of Common Corporate Costs" discussed in Exhibit C1, Tab 5, Schedule 1.

Information Technology (IT) tools, systems and infrastructure are required to facilitate distribution system operations. The primary systems supported by Operations OM&A are:

- The **Outage Response Management System** (ORMS) is the distribution outage management tool that automatically analyzes trouble calls received at the Customer Call Centre and predicts the location of faulted equipment, extent of an area experiencing an outage, identifies all affected customers and facilitates optimal dispatch of field crews.

- The **Interactive Voice Response (IVR)** system is the tool used to advise customers of the status of an outage affecting them. The IVR is set automatically by ORMS after it has determined all affected customers for an outage location. This significantly reduces the call volumes that agents need to handle at the Customer Call Centre.

- The OGCC **Integrated Voice System (IVS)** is designed to allow OGCC Operations to effectively manage voice communications with major customers and field staff. This system provides the interface to the public telephone network and Hydro One's provincial mobile radio system.

- The **Provincial Mobile Radio System** is the medium used by the OGCC and the field operations centres to maintain continuous contact with field crews. It is designed to be reliable in the event of widespread distribution outages and capable of accessing remote locations where field crews would be dispatched.

- The **Wireless Broadband System** (WiMAX) is the means by which the OGCC will send and receive Supervisory, Control and Data Acquisition (SCADA) signals with smart grid devices. This will include signals to operate remote devices being installed on the distribution system as well as receive telemetry and information (i.e. fault location) from sensors being deployed on the distribution system. Hydro One is leveraging the wireless spectrum (1.80-1.83Ghz) granted to utilities, specifically for protection of critical infrastructure.

- The **Network Management System (NMS)** is the network tool which performs data acquisition and supervisory control of the transmission system and a portion of the distribution system where OGCC Controllers are the operating authority. It provides monitoring of real-time voltages, frequency, loading, equipment status and annunciates alarms for the change in status of equipment or for equipment in an abnormal operating condition. The NMS also provides control of Hydro One assets in order to switch equipment in and out of service for outages, react to contingencies and change system configurations to provide reliable service to customers. The NMS is continuously being updated to provide additional visibility to the distribution system in unison with smart grid initiatives and distributed generation connections.

- The Distribution Management System (DMS) will monitor and control the distribution system assets. This system will communicate with the new remote controllable and telemetered devices to be installed on the distribution system through grid modernization activities. It will provide a series of power applications focused on the distribution system. These applications include:

    - State Estimation of the distribution system which factors in the effects of renewable generation, providing Controllers with information on the real-time direction of power flows;

- A Fault Location application which allows field crews to find faults on the distribution system faster and decreases the restoration time to restore power; and
- A Load Flow application that allows the OGCC to conduct studies of the distribution system for planned and forced outages.

- **Operations Support Tools** provide network outage management, Utility Work Protection Code (UWPC) and electronic logging (EL) functions:

  - **Network Outage Management System (NOMS)** is the transmission and distribution outage management tool that is used for planning, scheduling, assessing and executing outages. In addition, this system is used for transmitting outage requests via a direct communication link to the IESO (Independent Electricity System Operator) for approval.

  - The **Utility Work Protection Code** (UWPC) is used by most distributors in Ontario including Hydro One, when equipment is required to be in a guaranteed condition or status for personnel protection during the performance of work. This program contains the necessary information and tools to support the development of Work Protection packages.
  - **Electronic Logging** is the system of record for control room activities such as, but not limited to; system outages (planned and unplanned), work protections, location of crews and the change in status or condition of equipment. Electronic logging provides system data for distribution asset management and system planning.

- The **Distribution Operating Maps and Station Diagrams** are used by field crews and by the OGCC to provide detailed information on the normal operating configuration of the distribution system along with the connectivity of the distribution station and generation equipment. This information is essential for ensuring safe and reliable operations.

- The **OGCC Weather System** provides real-time weather information regarding storm systems, icing and flashover conditions and lightning activity that is critical to managing the distribution system. The information is used to predict and anticipate outage conditions and to notify field crews of impending bad weather. It is displayed on the control room workstations as well as the Control Room Wallboard Display.

- The **Emergency Services Information System (ESIS)** provides verified up-to-date contact numbers for all emergency service providers (i.e. Police, Fire, Ambulance, Ministry of Environment, gas utilities, etc.) across the Province. This system is designed to enable OGCC and field staff to efficiently contact emergency personnel. Access to ESIS is provided across Hydro One.

- The **Control Room Wallboards and Displays** are capable of displaying real-time information provided by OGCC systems and tools. The Wallboard Display, which spans the length of the Control Room, provides enhanced situational awareness and an overview of system conditions.

- **Media Notifications** provide local media and civic authorities with electronic notifications regarding unplanned outage events and restoration efforts, especially during storms. Media notifications can be distributed according to various local Hydro One geographical areas. This system is considered critical to maintain Hydro One's customer satisfaction rating.

3.0 PROGRAMS

Distribution Operations OM&A programs are divided into four categories, Operations, Operations Support, Environmental, Health and Safety and Smart Grid.

- Distribution Operations funds the staff required for the real-time distribution operating functions.
- Distribution Operations Support funding ensures the various systems and tools are kept current and functioning as required. Specifically, this program provides for the maintenance of the computer tools and systems for the Operating function.
- Environmental, Health and Safety funds initiatives required to support environmental, health and safety activities and corporate health and safety objectives.
- Smart Grid funds the maintenance and support of the smart grid-related computer tools as well as additional staff to leverage the new smart grid business capabilities.

Funding levels are illustrated in Table 1.

Table 1
Operations OM&A
($ Millions)

Description	**Historic**				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Operations	12.3	13.0	14.8	15.0	16.7	16.9	17.1	17.1	17.4	17.6
Operations Support	4.4	4.2	4.8	5.5	5.2	5.4	5.4	5.5	5.5	5.6
Environmental, Health & Safety	1.9	0.9	1.4	2.3	2.4	2.7	2.8	2.6	2.6	2.7
Smart Grid*	N/A	N/A	N/A	N/A	6.1	5.3	9.1	9.6	16.8	15.1
Total	**18.6**	**18.1**	**21.0**	**22.8**	**30.4**	**30.3**	**34.4**	**34.8**	**42.3**	**41.0**

*Smart Grid OM&A costs prior to 2014/2015 were part of the Smart Grid Pilot project and outlined in Exhibit C, Tab 1, Schedule 1 in application EB-2013-0141.

- The increase in Operations expenditures from 2010 to 2011 is attributed to an organizational realignment. Customer Operation Support (COS), formerly part of the Large Customer and Generator Relations group was moved under Operations.
- Increases in Operations expenditures from 2015 to 2019 are related to collective agreement obligations regarding the compensation of staff.
- Environmental, health and safety increases from historic to bridge and test years are due to the additional audit requirements to maintain OHSAS 18001 (Health & Safety Management System) certification and the costs to prepare for and to certify under ISO 14001 (Environment Management System).

- Smart Grid expenditures from 2015 to 2019 are related to the support of the Distribution Management System and other smart grid systems as well as staff to monitor and operate through the test years. The expenditures increase over the period as new systems are being commissioned over the test years.

3.1 Operations

Specific Operations functions include managing planned and unplanned outages, coordinating emergency response and monitoring system performance. These activities are described in greater detail below:

3.1.1 <u>Management and Implementation of Planned Outages</u>

Planned outages on the distribution system are managed by the Control Room, and typically account for between 5% and 15% of the duration of all Hydro One distribution customer outages. Applications for planned outages are coordinated to capture efficiencies and mitigate impacts on customers. This involves:

- Assessing all equipment involved in the outage to determine appropriate limits and control actions;
- Identifying and notifying customers of upcoming outages using means such as auto-dialer, phone, fax, newspapers, flyers, radio and door-to-door visits;
- Addressing customer concerns regarding outages by moving, where possible, the outage times and dates, transferring customers to other distribution sources, or providing a back-up supply source to ensure reliability; and
- Establishing UWPC conditions as required for all outages to ensure the safety of Hydro One staff and others.

3.1.2 Response and Management of Unplanned Outages

Equipment failures, tree and vegetation contact, road accidents, severe weather and lightning result in interruptions to the distribution system and cause unplanned outages. Unplanned outages typically account for 85% to 95% of Hydro One Distribution total customer outage durations. Restoration efforts depend on field crews locating the cause of the outage. Once the location of the faulted equipment is determined, the OGCC dispatches repair crews. The OGCC tracks the progress of the crews effecting repairs and communicates to customers. Affected customers are kept advised of the interruption status through the use of the IVR system, which informs customers that the problem is known, crews have been dispatched and the estimated time of power restoration.

Hydro One now offers a popular free, downloadable outage tracking mobile application (app) compatible with Android, BlackBerry and iPhone, smartphone and tablet devices. The app allows customers to identify the affected areas, check the status of unplanned/planned power outages, crew status, estimated time of power restoration, cause (if known) and the number of customers affected anywhere within Hydro One's service area.

3.1.3 Emergency Response Coordination

When the Hydro One distribution system experiences widespread interruptions due to weather impacts, an emergency response system is implemented. The level of response varies according to the area(s) and number of customers affected and the expected duration of the interruption. The DOMC will dispatch crews normally until a decision is made based on volume of power-off calls, to move to Field Operations Centre Dispatch mode. In this mode, customer power-off calls are spread out over the field operations centres to allow supervisors to dispatch crews at a more local level and manage their resources more efficiently. If the emergency is significantly widespread, Incident Command Centres (ICCs) and Forward Command Posts (FCPs) are established to centralize a local area command structure to address resources, material requirements and restoration activities. These efforts are coordinated through periodic conference calls initiated by the DOMC. The DOMC provides media notifications to keep Hydro One Distribution customers, municipalities and other agencies advised of outage progress updates.

3.1.4 System Performance Monitoring and Reporting

Reliability information used to identify emerging issues is needed to support sustainment and development decisions and to report on system performance to the Ontario Energy Board (OEB), customers and other stakeholders. Data required to calculate the standard reliability indices such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) is acquired at the OGCC. Outage inquiries from customers are reviewed and the data extracted from the various systems to further trend emerging performance issues and establish any additional plans that may be required.

3.1.5 Operations Summary

All of the aforementioned Operations functions continue to be impacted by smart grid and distributed generation activities. These activities are necessitating greater operational visibility and control of the distribution system. Existing processes and systems continue to be leveraged and an increasing number of OGCC staff focusing on distribution elements will continue to be used to manage these requirements.

This funding will ensure that distribution Operations will continue to deliver its core functions which includes managing and operating the distribution system, scheduling and overseeing planned outages, reacting to unplanned outages, coordinating emergency response, communicating with customers and monitoring system performance. Over the five year test period, Operations costs increase by a total of $0.7 million dollars which is approximately a 4.0% increase. Cost variability from year-to-year can be affected by factors such as storm activity and planned outages.

3.2 Operating Support

As highlighted in section 2.0 of this exhibit, Operations relies on a number of systems and tools to manage and operate the distribution system, as well as the redundant Back-Up Control Centre (BUCC). Operating Support funding is related to these systems and tools and includes expenditures for ongoing updates to the NMS and DMS to provide additional monitoring and control, support costs for ORMS, updates to the distribution operating maps and station diagrams, emergency preparedness, and the allocated portion of the maintenance and upkeep of operating facilities at the OGCC and the BUCC. Greater numbers of distributed generation connections have significantly influence the requirements for support (e.g. changes to station and operating diagrams, updates to the DMS network model and NMS extensions).

Distribution Operations Support is organized into investment programs. These programs include Operating Power Systems IT Support, Integrated Voice System Support, OGCC Data Collection and Information Updates, Operating Emergency Preparedness – Lines, Field Verification of DS Operating Diagrams, and Distribution Operating Maps (DOMs) maintenance.

3.2.1 Operating Power System IT Support

This investment provides funding to maintain support for operating computer tools and systems related to the operation of Hydro One Distribution's assets to ensure safe, reliable, efficient and cost effective delivery of power to Hydro One customers. Investment categories include ORMS, DMS, NOMS and other system applications, data services, architecture and infrastructure management, voice communication systems, IT building facilities, system control support and program management. Typical services include power restoration, system operating, capacity planning, lifecycle management, performance management, change management, configuration management, release management, and minor modifications.

3.2.2 Integrated Voice System Support (IVS)

This investment funds the maintenance program for the control room voice communication system and provides for essential expert telecommunications support. The integrated voice system is Operating’s method of communicating with Customers and Field Crews involved in the management and operation of the distribution electricity system. The IVS provides integrated access and intelligent call routing via multiple communication methods (i.e. Provincial Mobile Radio System, and Public Switched Telephone Network) by incorporating multiple technologies (i.e. IVR technology, Rolodex, Intercom, Voice Messaging, and conference bridge functions) to provide efficient management of hundreds of control room calls each day.

3.2.3 OGCC Data Collection & Information Updates

This investment funds the demand category work required to update the Distribution System Connectivity Information and to gather accurate field information describing equipment additions and changes on the Distribution Electric System. Accurate and timely data collection is required to ensure safe and reliable operation and management. Field data updates ensure that the ORMS and DMS accurately represent the Distribution System. Accurate information is also required to communicate the most up to date information to customers regarding any planned or unplanned interruptions through the IVR.

3.2.4 Operating Emergency Preparedness – Lines

This investment funds the annual work required of Provincial Lines to perform emergency generator testing, emergency communications testing, annual reviews of emergency preparedness procedures and the execution of emergency drills and exercises to ensure the appropriate level of preparedness.

3.2.5 Field Verification of Distribution Station (DS) Operating Diagrams

This investment funds the verification of the accuracy of DS operating diagrams. The initial field verification of DS operating diagrams was completed in 2007. An annual work program is required to verify the continued accuracy of the operating diagrams and to create diagrams for any newly installed DSs. Approximately 10% of the distribution station facility diagrams are re-verified annually. Over a 10-year period all DS and Regulating Station (RS) operating diagrams will be field verified for a second time. Network Operating requires the ability to request an emergency verification of operating information under this program or to request an increase in the number of stations verified annually. These diagrams are used by Control Room and field staff to create UWPC Work Protections and Supporting Guarantees for external staff to create a safe work area.

3.2.6 Distribution Operating Maps (DOM) Maintenance & DS Operating Diagrams

This investment funds the demand category work required to maintain, update and print Distribution Operating Diagrams and Maps. Demand work is defined as work where the volume of work is not fixed. Often this work is completed on a priority basis or to facilitate up-coming planned outages.

3.2.7 Operations Support Summary

This funding will ensure the required maintenance and support of the distribution Operations systems and tools required to execute core functions. Over the five year test period, Operations Support costs increase by a total of $0.2 million dollars which is approximately a 3.7% increase.

Distribution Operations are essential activities for the safe and reliable supply of power. Any funding reductions in these programs will negatively impact customer reliability, efficiency of power restoration and the safe operation of the Hydro One distribution system.

3.3 Environmental, Health and Safety Programs

Programs that are funded through “Greener Choices” and “Environmental, Health and Safety” span both transmission and distribution; therefore the following information will apply to both. These drivers support environmental, health and safety programs that are required to meet legal obligations and ensure a level of due diligence commensurate with the size and scale of Hydro One Networks. In addition, that program funds activities to assist in meeting the corporation’s Environmental and Safety performance targets.

Greener Choices activities funded by this investment include support of the Corporate Environment Policy by promoting employee awareness on environmental impact reduction, creating a culture of conservation within Hydro One, helping to make Hydro One facilities more energy efficient and reducing emissions from Hydro One fleet vehicles.

Environmental, health and safety activities funded by this investment include:

- Occupational and non-occupational injury/illness support which includes medical assessments of workplace injuries and illnesses (occupational); the Care Management Program which provides the right care at the right time for Hydro One employees who suffer a major medical absence of five days or more (non-occupational); and Pandemic planning (occupational and non-occupational);

- Hazardous Materials Management which identifies hazardous materials and establishes a protocol for on-going management of these materials in the workplace as per the Occupational Health and Safety Act (i.e., designated substances such as asbestos, lead, mercury);
- Public safety which includes school presentations, community events, fall fairs, media campaigns and the development and production of educational material to inform and educate members of the public about the hazards associated with Hydro One's assets;
- Proactive forums to assist the health and safety of employees by raising awareness and providing education about health, wellness and lifestyle issues;
- E-learning modules continue to be developed and or refreshed to enable employees to be trained remotely and to allow for timely and immediate delivery of required training. E-learning contributes to employee competence and reduces delivery costs;
- Development and implementation of new training media to improve the effectiveness of trades training. Web casting, video streaming, mobile learning, simulation and knowledge transfer technologies are being considered. This is used in trades and technical training;
- The Journey to Zero initiative which supports the objective to eliminate workplace injuries and illnesses through the use of cross-functional teams carrying out review of specific functional areas impacting on safety performance and providing opportunities for improvement;
- Maintenance of Hydro One's OHSAS 18001 Registration including ongoing system and field audits to ensure Hydro One's Health and Safety Management System is meeting the OHSAS standard and closing of any identified gaps;
- Obtaining ISO 14001 certification for Hydro One's Environment Management System. Certification requires a complete review of Hydro One's current environment

management system compared to standards, field auditing of execution and closing of any identified gaps; and

- Ice and Water rescue training for staff who work on and around water and ice so that they are prepared to meet the hazards in these environments.

3.3.1 Environmental Health and Safety Summary

Environmental, health and safety increases from historic to bridge and test years due to the additional audit requirements to maintain OHSAS 18001 (Health and Safety Management System) certification and the costs to prepare for and to certify under ISO 14001 (Environment Management System).

3.4 Smart Grid

As part of its Green Energy Plan filed in EB-2009-0096, Hydro One detailed its plan to pilot smart grid technologies in a trial area and then deploy those technologies on a wider basis once validated. In its EB-2012-0136 and EB-2013-0141 filings, Hydro One specified funding for operating, supporting and maintaining deployed smart grid assets. As Hydro One begins the process of modernizing its distribution system, Hydro One will continue to operate, support and maintain an increasing set of smart grid assets as part of its normal utility operations.

3.4.1 Operations for Smart Grid

This investment funds the staff, and training in new tools and procedures, to support proactive smart grid-enabled operations. In the past, Hydro One has had little real-time situational awareness of the distribution system and has been dependent on customer calls to notify Hydro One of issues. Through grid modernization and the installation of smart grid devices on the distribution system, Hydro One will be able to remotely monitor and control parts of the distribution system and respond to operational issues that arise in real-time, before customers call.

3.4.2 Operations Support for Smart Grid

This investment funds the maintenance, support and software upgrade of smart grid systems. Hydro One has already installed a base of new smart grid assets including a Distribution Management System. Through the releases of the smart grid project, additional systems will be commissioned and in-serviced. These systems will also require support and maintenance. The investment will provide:

- staff to support the computer infrastructure and software systems;
- staff to maintain the distribution network model;
- software maintenance; and
- licensing fees amongst other costs.
-

3.4.3 Telecommunications Support

This investment funds the monitoring and maintenance of the telecommunication infrastructure required to support the smart grid assets to be deployed on the distribution system. This infrastructure will enable Supervisory Control and Data Acquisition (SCADA) for Operations to control and monitor smart grid assets.

3.4.4 Smart Grid Summary

As per the Board’s direction in the Renewed Regulatory Framework (October 2012), Hydro One has integrated its smart grid investment as part of its normal investment plans for the first time. In prior years, smart grid expenditures were detailed in Hydro One’s Green Energy Plan (EB-2009-0096) or in its request for specific Smart Grid Rate Riders (EB-2012-0136 and EB-2013-0141). The expenditures increase over the period as new smart grid systems are commissioned and an increasing proportion of the Hydro One distribution system is modernized.

CUSTOMER SERVICE OM&A

1.0 INTRODUCTION

Hydro One's Corporate Strategy is fully committed to customer satisfaction and an improved customer experience. In its dialogue with customers, Hydro One focuses on understanding customer needs and their definition of value. It communicates to customers the value provided through its focus on productivity. It pursues growth opportunities that produce efficiencies and provide economic and improved service benefits to its customers. It develops and delivers targeted customer segment strategies, products and delivery channels that will respond to their unique needs. This includes benefits from our new Customer Information System (CIS), continuously improving our process to meet customer commitments on outages, and continuing to focus on delivering conservation and demand management programs that help its customers better manage their bills.

Hydro One's Customer Service OM&A represents the set of work activities required to develop, implement and monitor the Corporation's plans to positively influence the relationship, affordability and overall value proposition for the products and services offered to customers. These work activites will enable Hydro One to foster a relationship based on transparency and trust, while ensuring customers understand the value Hydro One provides in their communities.

The work activities include: improving customer experience when dealing with Hydro One, overseeing meter to bank operations, management of key relationships with large customers including distributed generators, and continued development of Hydro One's Smart Grid.

Table 1: Customer Services Costs by Function ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer Operations	105.5	101.3	105.2	118.7	109.2	96.8	96.2	96.6	98.0	99.6
Distributed Generation	5.0	9.5	9.0	7.3	7.7	7.9	8.1	8.3	8.5	8.7
Conservation & Demand Management	1.7	2.0	1.6	2.4	3.1	3.1	2.7	2.7	2.8	2.8
Customer Experience	0.0	0.0	0.0	1.9	4.2	4.3	4.3	4.3	4.2	4.3
Smart Grid Pilot	2.5	0.4	0.8	7.0	9.5	5.7	4.9	2.8	0.0	0.0
Total Customer Services	**114.7**	**113.3**	**116.7**	**137.3**	**133.7**	**117.8**	**116.2**	**114.7**	**113.5**	**115.4**

During 2013 and 2014 costs are higher than the historical baseline due to the increased costs associated with the implementation of the new Customer Information System (CIS). As the system stabilizes, overall customer services costs are reduced through the test years due to the realization of the numerous productivity benefits of the new system. These benefits include; a new billing application for easier customer interaction regarding billing questions and improved tracking of collection issues. The introduction of Customer Experience work activities in 2013 will continue to shape the company's vision for the ideal customer experience and assist in moving Hydro One toward a 90% customer satisfaction target in 5 years.

2.0 CUSTOMER OPERATIONS

Customer Operations OM&A represents the set of work activities required to provide services to customers connected to the Hydro One Distribution system, improve customer satisfaction, and to meet the relevant service levels stipulated in the Electricity Distribution Rate Handbook, Chapter 15, Service Quality Regulation and the Distribution Service Code. Services are provided in accordance with Hydro One's Conditions of Service, relevant Codes and legislative direction.

The Customer Operations Work Program includes service programs and projects, including: meter reading, billing, settlements, customer contact handling and collections. Project work includes regulatory compliance initiatives and service enhancements.

Customer Operation programs are provided to approximately 1.3 million customers who are connected to Hydro One Distribution's system. These customers are in residential, seasonal, farm and general service customers segments, as well as sub-transmission ("ST") and distributed generation classifications. The services are provided to customers purchasing electricity through Standard Supply Service or under Retailer contracts.

Table 2: Customer Operations Costs by Category ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer Service Operations	42.1	41.6	41.7	47.2	40.9	33.4	33.4	34.4	35.3	36.4
Meter Reading	12.7	8.8	15.9	20.0	20.0	14.9	14.3	14.0	14.0	14.1
Field Support	9.9	8.5	9.2	7.1	7.4	7.1	7.3	7.5	7.5	7.6
Service Support	10.3	10.2	9.9	10.9	11.3	11.9	12.2	12.5	13.0	13.4
Customer Services Management	6.8	6.5	7.4	11.5*	11.4	11.3	11.0	11.1	11.3	11.5
Bad Debt	17.7	18.8	18.8	20.0	15.1	15.5	15.4	14.4	14.1	13.7
Regulatory Compliance	4.9	5.5	1.7	1.2	1.6	1.6	1.6	1.6	1.6	1.6
Service Enhancements	0.4	0.7	0.2	0.3	0.8	0.3	0.3	0.4	0.4	0.4
Customer Business Relations	0.8	0.7	0.5	0.5	0.8	0.8	0.8	0.8	0.8	0.8
Total Customer Operations	**105.5**	**101.3**	**105.2**	**118.7**	**109.2**	**96.8**	**96.2**	**96.6**	**98.0**	**99.6**

*The dollar increase is largely due to historic costs being reflected in the Asset Management and Operations Lines of Business.

2.1 Customer Service Operations

Customer Service Operations costs include: the delivery of bills, contact handling, collections, settlement services and customer business relations, which are included in the contract with Inergi LP (Inergi). Although these services are delivered by Inergi, Hydro One retains direct accountability for customer policy, planning, work program budgeting and service performance management. The focus of this work is to translate corporate customer objectives into Inergi service delivery results, and to build a healthy buyer-vendor relationship that allows Hydro One to benefit from the specialized expertise of the outsourcing partners.

During this five year test period, the existing outsource agreement will expire and Hydro One will establish a new agreement. The current expectation is Hydro One will establish new agreements with one or more vendors with similar scope as the existing agreement with Inergi. Hydro One's role with the new agreement(s) is expected to remain consistent with translating the corporate strategies and objectives into the vendor's performance results. Customer Service Operation costs are planned to initially decrease with the negotiation of the new outsource agreement and the realization of CIS benefits as compared to the bridge and the historic years. The outsource contract is expected to remain flat except for the effects of inflation over the test year period.

Customer Service Operations also manages customer research and surveying, the resolution of escalated customer complaints, management of retail and wholesale settlements, as well as policy planning and account management for distributed generation customers.

2.1.1 Billing

This program covers delivery of the billing process, including validation and editing of meter reading data, bill calculation, exception handling, accuracy management, retailer transactions, bill creation, bill insertion and issuance, and receivables processing. Customers are issued monthly bills except seasonal customers who are billed quarterly.

Hydro One is implementing a number of initiatives to improve billing services for customers and help reduce operational costs. New initiatives include: reviewing the bill format to improve information provided to customers and increasing the number of customers enrolled with electronic billing (via ePost or Hydro One's self-serve website).

The new CIS will provide billing and back office savings through the use of a new exception handling tool. The Meter To Cash Composite Application (MTCCA) provides an integrated end to end view of all exceptions affecting a customer's account and presents them in a hierarchal logical order so that the right exceptions are addressed first.

2.1.2 Collections

This program includes collection processes and events associated with recovering electricity revenues for both active and final-billed accounts. This work includes issuing collection letters and notices and, if required, disconnection orders, running automated telephone call campaigns of arrears reminders, and managing performance of third-party collection agencies that follow up on outstanding final-billed accounts. The program's focus is to reduce arrears and bad debt while working with customers on a variety of payment options. In addition, the program responds to powers of sale, foreclosures, bankruptcies and receiverships, debt reviews, consumer and business proposals, and theft of power cases.

Hydro One has added processes and initiatives to manage collections costs, increase flexibility of collection actions, provide more notice and improve ease of making payments of past due amounts. Hydro One has recently added Canada Post Money

Gram and Western Union Quick Collect as new payment channels to increase customer choice and payment flexibility.

The new CIS will provide collection benefits through: improved tracking of delinquent customers, more robust collection campaigns, and the enenablement of remote disconnections and reconnections.

2.1.3 Contact Handling

Hydro One's Distribution customers contact the Company in several ways including telephone, letters, faxes, email, self-service features via the Interactive Voice Response (IVR) technology and the Company's website. This program covers the management of customer contacts at Hydro One’s contact centres in Markham and London. The contact centres handle approximately 2.5 million calls a year from Hydro One customers and manage all areas of customer call activity, including bill and account enquiries, collections, outages and emergencies, and service requests.

In addition to responding to customer calls, the contact centres respond to inquiries received via other methods, including: customer letters; lawyer letters for move-in and move-out requests; customer and contractor faxes; and customer email. In addition, the contact centres issue pamphlets, letters, copies of bills, welcome packages, or a summary of Hydro One Distribution's Terms and Conditions of Service.

Recent and upcoming initiatives continue to contribute to an improved contact experience for customers. Recent initiatives include a quality monitoring program, an automated call back service for periods when wait times are longer than two minutes to reach an agent, the introduction of specialized energy conservation information, and enhancements to the IVR system.

2.1.4 Settlements

The Settlements program ensures the integrity of financial transactions between Hydro One, the Independent Electricity System Operator (IESO), and applicable customers, both load customers and distributed generators. The program includes reconciling purchases of energy and transmission service from the IESO as a distributor, reconciling transmission revenues received from the IESO as a transmitter, billing the approved distribution tariffs (including retail transmission, commodity and others) and energy prices for all complex customers, and settlements for short and long-term load transfers. The Settlements program provides the appropriate level of due diligence to ensure that billing and payment transactions are reconciled accurately for parties involved, and ensure that affected customers receive timely and accurate bills.

2.2 Meter Reading

This program includes work to support automated reading of smart meters, specific manual meter readings, and remote reading of interval meters. Hydro One has approximately 1.3 million smart meters deployed to its customers.

Smart Meter & Network Operations (SMNO) provides accurate measurement and delivery of “bill ready” consumption data as well as the sustainment of Life Cycle Management including hardware and data integrity. This includes using approved Advanced Metering Infrastructure (AMI) components such as meters, repeaters, collectors, instrument transformers, and communication networks. In addition, this work ensures that all software, firmware and head end systems are compliant with Hydro One and Measurement Canada requirements.

SMNO operates Hydro One's AMI network and data collection facilities to ensure smart meters are communicating, provide meter data investigation services, and ensure appropriate parties respond to assigned issues to meet performance requirements. The team responds to technical errors reported by other groups, confirms that meter configurations are correct and maintains end to end communication and performance of Hydro One's AMI Network.

Although the volume of manual meter reads has decreased since the installation of smart meters, approximately 70,000 meters still require a visit by field staff to the customer premise due to limits in reach of the Smart Meter Network infrastructure. The remaining customers that still require a manual meter reading are spread across the province, thereby increasing the cost per read. Hence, meter reading is still a substantial cost and Hydro One continues to review available advances in technology to provide cost effective options towards reaching these meters. Manual meter reading costs also include ancillary charges required for support activities, such as maintaining meter reading tools and reviewing demand charges annually.

2.3 Field Support

This work covers the field investigations required to support the billing, collections and settlements service programs. It includes the execution of service orders to disconnect or load limit electricity services due to non-payment, reconnect electricity services when payment issues are resolved, and in certain situations, follow up to ensure the integrity of a reconnect, disconnect, or load limiter. Field work is also requested to investigate high bill complaints, develop and revise revenue metering single line diagrams, and validate wholesale meter data which is required for settlements.

2.4 Service Support

This work reflects costs for a number of other third-party contracts not within the Inegi contract that are required for delivery of the services programs. These include postage and courier services to issue bills, telephone expenses including costs for 1-800 numbers, third party contracts held by Hydro One Distribution for centralized payment processing, service to provide electronic billing, and collection agency costs related to final bill collection activity. Costs are forecast to increase over the test period due to inflation.

The largest component of the Service Support Costs is related to the delivery of customer bills and postage costs. Over the test period, expected increases in the postage rate are the main driver for the increases in this category. Hydro One is actively promoting e-bill options to customers to help mitigate increase in such postage costs.

2.5 Customer Service Management

These work activities include the management to run the customer care programs including the resolution of escalated customer complaints, execution of critical settlement functions of local distribution companies and large accounts, performance management, contract management with outsourced companies, customer research and surveying, and project planning, delivery and implementation.

2.6 Bad Debt

This cost category reflects bad debt expenses, net of recoveries. Bad debt expense is expected to decline each year from 2015 to 2019 due to the benefits of the CIS project. The implementation of the new CIS allowed for the redesign of the business processes which are expected to improve the bad debt expense through the improved ability to track delinquent customers and eliminate final bills on move outs where the customer is moving back into Hydro One's service territory.

To help manage bad debt costs, additional collection methods have been introduced as well as being planned for the test years. Examples of these and other collection methods are noted in the description of the collection services program, Section 2.1.1 Customer Service Operations.

2.7 Regulatory Compliance

Regulatory compliance includes the administration of ongoing programs as well as one-time projects with non-system impacting changes, as directed by the Ontario Energy Board or the Ministry of Energy. The funding is required to remain in compliance with the terms and conditions of Hydro One's operating licence. The main project included in this area is the Low Energy Assistance Program (LEAP). Hydro One administers and funds $1.2M annually to the OEB Low Energy Assistance Program (LEAP), which provides emergency relief to eligible low-income customers. The United Way Greater Simcoe manages this Fund as Hydro One's Lead Agency.

2.8 Service Enhancements

Service enhancements represent investment in service or productivity improvements to customer service programs. The planned projects over the test period include the following: meter reading route optimization for those customers beyond the reach of the Smart Meter Network infrastructure; marketing campaigns and promotions to encourage Hydro One customers to subscribe to e-Post, thereby reducing costs for postage; marketing campaigns to support Hydro One's electronic billing platform, also known as Biller Direct; and enhancements for self-serve options via Hydro One's web site and the IVR, to address changing customer needs and expectations.

2.9 Customer Business Relations

Improving the level of service that the Company provides to customers is a key objective of Hydro One. Customer Business Relations (CBR) focuses its efforts on managing the relationship with large customers, including embedded Local Distribution Companies (LDCs) and Distribution Connected Large Accounts (> 2MW).

Core work programs include contract development, management, program implementation, customer communications, operational and business support, and customer connection project coordination. Planned long-term initiatives include power quality initiatives to define power quality events and mitigating actions, improving customer communications through enhanced Web self-service, skills training and new database functionality to increase customer knowledge, and improving commitment tracking and reporting. In addition, as new Conservation and Demand Management (CDM) programs are developed in this customer segment, the CBR group will become accountable for delivery and will work to ensure that all targets are achieved.

3.0 DISTRIBUTED GENERATION

The Distributed Generation program manages and maintains the relationship with the distributed generators pre and post connection while ensuring OEB mandated timelines are met. In order to meet customer expectations and OEB mandated timelines, Distributed Generation projects are monitored and managed within a Customer Relationship Management Database (CRM). The Distributed Generation team is accountable to manage the end to end connection process and ensure the process is continually improved and streamlined. Core work activities for the Distributed Generation Team include customer capacity availability consultations, customer application support, contract development, execution and management, customer communications and relationship management.

Table 3: Distributed Generation Costs by Category ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customer Operations	2.6	5.8	4.7	3.7	3.6	3.7	3.9	4.0	4.1	4.2
Settlements	0.1	0.7	0.9	1.1	1.4	1.4	1.5	1.5	1.6	1.6
Customer Care Management	2.3	3.1	3.5	2.5	2.7	2.8	2.8	2.8	2.8	2.9
Total	**5.0**	**9.5**	**9.0**	**7.3**	**7.7**	**7.9**	**8.1**	**8.3**	**8.5**	**8.7**

Costs have increased over the test period primarily due to the increased cost associated with the increase and complexity of the Distributed Generation projects. The number of distributed generators connected to Hydro Ones network has increased from 166 (Non MicroFIT) in 2009 to 11,117 (Non MicroFIT and MicroFIT) in 2013. It is expected that approximetly 6,000 micro-embedded generation facilities will be connected over the 5 year test period along with approximately 1,200 generation facilities (>10 kW). The team is required to support the full life of these contracts and the customer relationships. They manage the ongoing customer relationship; the completion of work to ensure achievement of OEB mandated requirements, the timelines and reporting requirements; and the settlements and payments to generators. In addition, generators are demonstrating a high rate of change of ownership which inceases the contract management activities with respect to both the associated Distribution Connection Agreement and OPA contract.

4.0 CONSERVATION AND DEMAND MANAGEMENT

Since 2005 Hydro One has delivered Conservation and Demand Management (CDM) programs aimed at reducing customers' individual consumption and the overall consumption on the electricity grid. Hydro One participates in OPA sponsored CDM initiatives such as Residential and Small Commercial Demand Response; Electricity Retrofit Incentive Program; and the Fridge and Freezer Pickup as well as Hydro One specific programs which will increase over the 5 year test period.

Table 4: Conservation and Demand Management Costs by Category ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Conservation & Demand Management	**1.7**	**2.0**	**1.6**	**2.4**	**3.1**	**3.1**	**2.7**	**2.7**	**2.8**	**2.8**

Under the *Green Energy Act* (GEA), CDM targets for the period of 2011-2014 are a condition of the Distribution License Agreement. On September 16, 2010, the Board issued a CDM Code that required LDCs to meet the four year targets through the delivery of OPA-Contracted programs and Board-approved programs until 2014. As a result, Hydro One has been participating in current OPA-administered CDM programs and has looked for opportunities to expand this program portfolio as appropriate. Since funding for these OPA-contracted programs have been recovered through the Global Adjustment Mechanism (GAM) from the OPA, it is not included in this Application.

Currently, Hydro One is working with the government and the sector to develop the next CDM framework, expected to cover the period of 2015-2020. Hydro One is seeking funding to support programs in the market to continue research and development, to collaborate with the sector and maintain a base level of CDM capability required to participate in industry activities, including testing of new technologies and delivery of pilot programs.

An example of a pilot program is the Green Button initiative. It enables customers to securely download their own easy-to-understand energy usage information online. Consumers can then use new web and smartphone tools to make more informed energy decisions, optimize the size and cost-effectiveness of solar panels for their home, or verify that energy-efficiency retrofit investments are performing as promised.

5.0 CUSTOMER EXPERIENCE

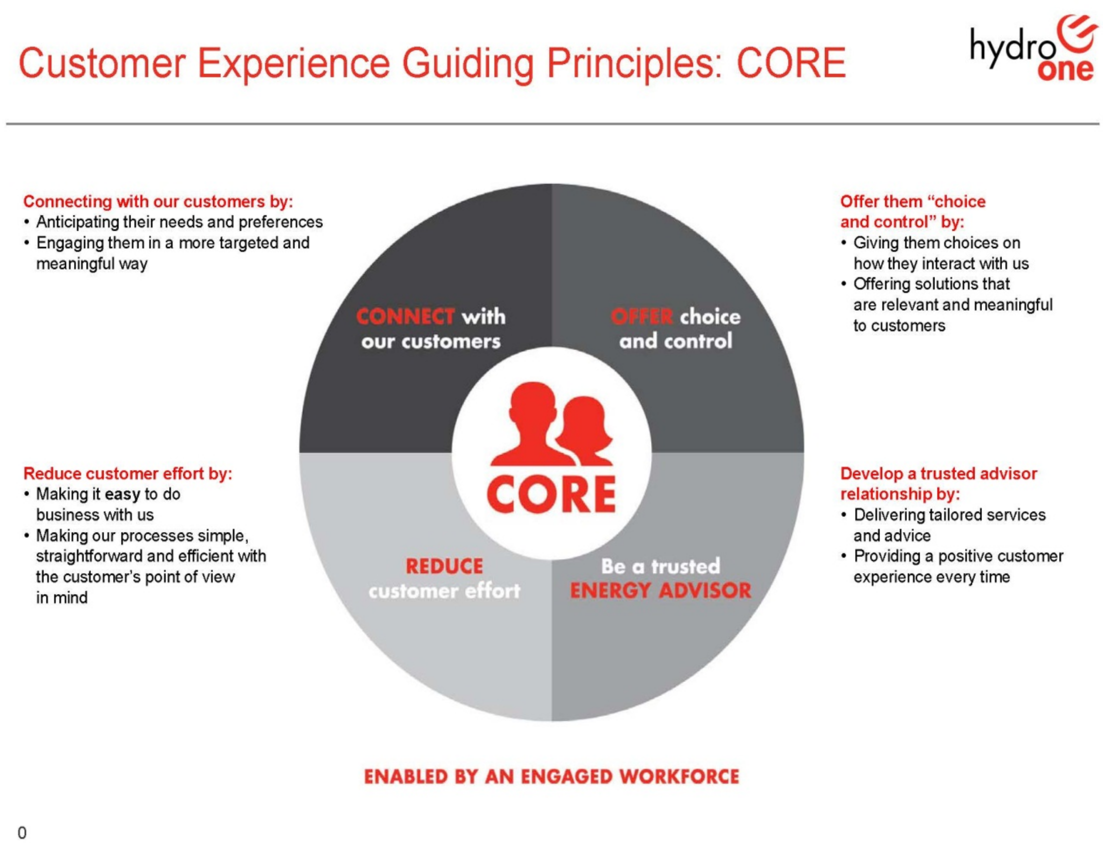
Table 5 – Customer Experience (Costs by Category ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Customer Experience	0.0	0.0	0.0	1.9	4.2	4.3	4.3	4.3	4.2	4.3

Customer Experience (CE) OM&A reflects the set of work activities required to continue to shape the company's vision for the ideal customer experience, allowing Hydro One to more effectively respond to evolving customer needs and expectations as described in the Introduction of this Exhibit as well as in Exhibit A, Tab 5, Schedule 1.

The Customer Experience work activities includes conducting a comprehensive analysis to better understand its current customer experience in comparison to external customer focused companies. Efforts are being made to meet the requirements of the Renewed Regulatory Framework and develop a strong understanding of Hydro One's customers: who they are, what they want and need, and how they perceive their interactions with our company.

This work has lead to the following set of guiding principles that are being implemented across the Company.



6.0 SMART GRID PILOT

Hydro One's smart grid pilot project is a multi-year initiative to identify, deploy, and analyze applications, equipment, and business processes in support of the following five business objectives:

- **Distribution Generator (DG) Enablement:** Ensure the ongoing, efficient operation of the system while facilitating the addition of a significant amount of new distributed generation capacity to Hydro One's distribution system.

- **Distribution Reliability/Operations Improvements:** Automate Hydro One's distribution system in varying degrees to provide further real-time monitoring, control, automatic restoration and optimized operations, thereby improving reliability, reducing overall utility costs and improving customer satisfaction.

- **Outage Restoration Optimization:** Take advantage of real-time capabilities and enhanced workforce mobilization to minimize customer outage duration through quicker and more efficient fault restoration.

- **Distribution Network Asset Planning and Tools:** Provide improved tools for assessing and planning changes to the distribution network, including the installation of distributed generation facilities.

- **Customer Enablement:** Provide customers with tools for managing and understanding their electricity usage, including the installation of in-home displays and energy management systems.

Table 6: Smart Grid Pilot ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Smart Grid Pilot	**2.5**	**0.4**	**0.8**	**7.0**	**9.5**	**5.7**	**4.9**	**2.8**	**0.0**	**0.0**

Hydro One continues to execute its smart grid pilot project through 2017. Incremental OM&A is required to complete the smart grid pilot. It includes costs associated with software development, process development and training. Details of the history of this project as well as the pilot project that this OM&A will fund can be found in Section 2.0 of Exhibit D1, Tab 3, Schedule 5.

SUMMARY OF COMMON CORPORATE COSTS OM&A

Hydro One Common Corporate Costs OM&A is comprised of Common Corporate Functions and Services ("CCFS"), Asset Management Services, Information Technology ("IT"), Cornerstone, Cost of Sales to external parties and Other OM&A.

CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications, Legal, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate. Common Asset Management services include System Investment and Asset Stewardship and Strategies. IT and Cornerstone activities include providing and managing computer systems and installing enterprise IT systems. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

Hydro One utilizes a centralized shared services model to deliver its common services to the Transmission and Distribution businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom Inc., Hydro One Networks Brampton Inc., and Hydro One Remote Communities Inc. Many organizations have adopted a common corporate cost model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model when it was established in 1999. The additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive.

Table 1 summarizes the Distribution portion of the Common Corporate Cost and Other OM&A Costs over the Historic, Bridge and Test years.

Table 1
Allocated Distribution Corporate common costs and Other OM&A Costs
($ Millions)

Description	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Common Corporate Functions and Services	69.7	68.5	71.5	79.2	79.1	77.2	76.8	76.7	78.6	79.9
Asset Management	30.6	34.6	25.1	20.9	18.4	18.4	17.8	17.6	17.5	17.8
Information Technology	71.2	72.6	80.6	103.1	86.0	85.7	86.4	86.1	86.5	87.6
Cost of Sales	4.9	2.3	16.5	2.1	2.0	2.1	2.1	2.1	2.2	2.2
Other OM&A	-81.5	-92.4	-105.1	-102.6	-111.7	-116.7	-120.6	-120.1	-122.4	-125.2
Total	**94.9**	**85.5**	**88.6**	**102.8**	**73.8**	**66.7**	**62.5**	**62.4**	**62.4**	**62.3**

In the 2009-2014 period, Hydro One applied a cost allocation methodology developed by Black and Veatch Corporation (B&V) which utilizes a breakdown of activities and drivers. In 2013, the Company commissioned B&V to update the methodology to allocate common costs among the business entities using the common services, as discussed in Exhibit C1, Tab 5, Schedule 1. The approach utilizes a further breakdown of activities and drivers and is used in this application.

The reduction in OM&A spending in the test years 2015 through 2019 as compared to the historical years is primarily related to:

- CCFS costs increase slightly over the test years due to increased HR support for expanded field work programs and succession planning, long-term relationship building with First Nations and Métis communities and funding for the corporate records management project. See Exhibit C1, Tab 2, Schedule 8 for details.
- Lower Asset Management costs result from productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for the

organization, although the work undertaken by Asset Management is expected to increase. See Exhibit C1, Tab 2, Schedule 9 for details.

- IT costs are lower after 2013 due to the completion of the new CIS system and costs remain stable from 2015 to 2019. See Exhibit C1, Tab 2, Schedule 10 for details.
- Lower Other OM&A program cost is related to the increase in cost of remediation of environmental contamination. When these OM&A work program costs are incurred, there is a corresponding credit to OM&A for the environmental expenditures to reflect the fact that the cost is reflected in revenue requirement as amortization expense and not as OM&A, thus reducing overall OM&A costs.

OUTSOURCING

1.0 BACKGROUND

Hydro One Networks Inc. ("Networks") entered into a 10-year master services agreement with Inergi LP ("Inergi") on December 28, 2001 for services commencing on March 1, 2002 (the "Original Agreement"). Inergi is a limited partnership, a wholly-owned subsidiary of Capgemini Canada (formerly known as Cap Gemini Ernst & Young Canada Inc.) held by Capgemini SA. Under the Original Agreement, Hydro One outsourced its information technology services, customer service operations, settlements, source-to-pay, payroll, and finance and accounting services.

The Original Agreement provided for an optional 3-year extension to the original 10-year term.

Before the initial term of the Original Agreement expired, the parties agreed to amend the underlying business terms, effective as of May 1, 2010, to make them consistent with then current market practices and business requirements. The scope of work remained largely unchanged. Networks and Inergi both agreed to extend the Original Agreement by 3 years. The renewal permitted Networks to benefit from updated business terms earlier, including a 12% average annual reduction in fees over the remaining term of extended Original Agreement ("Current Agreement").

Leading up to the negotiations, Networks retained EquaTerra Inc. to develop and document expectations for the extended agreement to reflect market comparators, and provide negotiation support. In EquaTerra Inc.'s professional judgment the Current Agreement, taken as a whole, is market competitive. Inergi's affiliate, Capgemini US LLC, has provided a financial guarantee for payment upon demand of all guaranteed financial obligations, as well as a performance guarantee for the performance of all obligations under the Current Agreement.

The Current Agreement is subject to a *Declaration of the Sole Shareholder regarding the power of the Hydro One Inc.'s Board of Directors to enforce, including any and all other powers related to the Transfer ("Offshoring") of jobs out of the Province of Ontario under the Outsourcing Agreement entered into by Hydro One Inc. with Inergi LP ("Inergi") on or about December, 2001 (the "Outsourcing Agreement")* issued on September 24, 2008. The Current Agreement and the above Declaration will expire on February 28, 2015.

2.0 THE CURRENT AGREEMENT

2.1 Scope of Work

The scope of work under the Current Agreement is comprised of services ("Base Services") and project services performed over a finite period to produce a project deliverable, solution or result ("Project Services"). Base Services are divided into the following six areas (individually, a "statement of work" or a "SOW"), each of which relates to a line of business within Networks: (1) information technology services; (2) customer service operations; (3) settlements; (4) source-to-pay; (5) payroll; and (6) finance and accounting services. Appendix A contains the descriptions of Base Services contracted for each SOW.

2.2 Fees

Under the Current Agreement, Inergi provides Base Services based on a declining fee structure, except for the Settlements SOW for which the parties settled on a "cost-plus" pricing model due to the complex nature of the work. The fees for Base Services will decline over time so long as transaction volumes remain within normal volume ranges as defined in the Current Agreement while meeting or exceeding prevailing service levels. Additional charges apply if there are higher transaction volumes than the prescribed volumes. (For example, an increase in the number of Networks' customers may cause Networks to exceed certain volumes in the customer service operations SOW.) Conversely, Networks is entitled to fee credits if transaction volumes are lower than prescribed volumes.

For Project Services, Networks pays time-and-material rates. Networks receives an annual volume discount of up to 15% based on qualifying annual expenditures for Project Services.

All fees are subject to cost-of-living adjustments, using Statistics Canada indices of compensation for employees in Ontario and of the total number of employees in Ontario.

Appendix B to this exhibit sets out the outsourcing fees spent in the historical period 2010 to 2013 and the forecasted outsourcing expenditures for bridge year 2014 and test years 2015 to 2019.

2.3 Benchmarking Review of Fees

The Current Agreement provides for optional benchmarking reviews of fees by an independent third party, the costs of which are borne equally by Networks and Inergi. The third party analyst ("Analyst") is selected from a predetermined list included in the Current Agreement. Fees for the Settlements SOW are excluded from the review due to the unique and complex nature of the services and the absence of comparable suppliers.

The sample group in the benchmarking review consists of companies comparable to Inergi, meaning companies with the same line(s) of business and a comparable ratio of unionized and non-unionized resources. Where the proportion of unionized and non-unionized differs between companies, the Analyst shall normalize this difference. The Analyst will compare Inergi's fees with those of the sample group, adjusted for differences in volumes, scope of services, service levels, cost components and applicable cost of living increases with the market price.

In the fourth quarter of 2013, Networks exercised its right to a benchmarking review of Inergi's fees under the Current Agreement. Networks anticipates that a report will be completed by February 2014. The reviewer will be TPI Sourcing Consultants Canada Corp ("TPI"), an affiliate of Information Services Group Inc. If the comparison report reveals that the adjusted fees charged by Inergi, in respect of all services delivered within any SOW (excluding Settlements), exceeds the benchmark price as defined in Current Agreement, Inergi will be required to provide Networks with the equivalent of the benchmark price for the services in that SOW effective March 1, 2014. If the comparison report reveals that the adjusted fees are below the benchmark price, there will be no change to the fees charged by Inergi.

2.4 Royalty Payment and Provision of Facilities

Under the Current Agreement, Inergi makes annual payments to Networks in consideration of Networks' support of Inergi's broader marketing efforts.

Where Inergi staff are located in Networks' facilities, the cost of those facilities and facility overhead costs (communication services, heating, lighting, consumable goods, etc.) are borne by Networks.

2.5 Service Quality Assurances and Continuous Improvement

The Current Agreement sets out a methodology to measure Inergi's performance, which includes defined service levels or performance indicators ("PIs") and client satisfaction surveys. Inergi's services are measured regularly (monthly, quarterly, and yearly) for achievement of PIs. The PIs vary based on the nature of the service in question and set both minimum and targeted service levels. When Inergi fails to meet certain PIs, Networks is entitled to either: (a) a service credit(s) calculated in accordance with predetermined formuli, (b) at Inergi's cost, remediation action based on a remediation plan that Networks has approved, or (c) both, depending on the level of criticality and frequency of such failures.[1] The PIs are adjusted upwards annually, where applicable, to drive continuous improvement. In the contract year ending February 2013, Inergi met or exceeded 97% of all PIs.

Inergi performs client satisfaction surveys of Networks' relevant business managers and internal users. Inergi must address dissatisfaction revealed by the surveys. Together, the parties are to identify opportunities and strategies for responding to any issues the surveys reveal. The scores of these surveys have recently been 3.9 out of 5 for Base Services and 4.0 out of 5 for Project Services.

The Current Agreement also prescribes a process whereby Inergi continually introduces global best practices from Capgemini to Networks. As of mid-2013, Inergi has generated initiatives which have resulted in cost savings, primarily across strategic sourcing and

[1] Termination of individual statements of work or any part thereof is allowed under defined circumstances without payment of any penalties or termination charges.

infrastructure storage reductions. The initiatives are presented to and reviewed by Networks.

The Current Agreement sets out a governing structure to manage the parties' relationship, which includes the Joint Executive Committee, the Joint Governance Committee, the Joint SOW Oversight Committee, and the Joint Service Leadership Committee. These committees meet regularly, at different intervals, to ensure strategic alignment between the parties, oversee relationship, review Inergi's global business strategies, review operational performance, change management, business planning, continuous improvement, and manage and resolve any risks and issues.

2.6 Protecting against business interruption

There are multiple safeguards against business interruption in the Current Agreement. Inergi is required to develop, maintain, test and execute business continuity and disaster recovery plans. Inergi must maintain and exercise these plans in a state of readiness for execution at all times. If there is a change in the services which impacts the plans, Inergi must modify the plans and, where necessary, retest them to maintain the state of readiness.

2.7 Transition at the end of the Current Agreement

To prepare for the expiration or full or partial termination of the Current Agreement, Inergi must: (a) provide and maintain a comprehensive termination transition plan at its own cost, and (b) for additional compensation, provide termination transition services described therein. The transition plan must lay out all the information required to enable Networks or a third party to take over provision of the services on a partial or full termination of the Current Agreement in an orderly, cost-efficient, and timely manner.

This is expected to reduce the risks of transition and operational problems by facilitating knowledge transfer to the successful supplier(s).

The termination transition plan was activated on September 1, 2013 (the "Transition Plan"), 18 months before the expiry date of the Current Agreement. The plan includes a number of preparatory activities in the first stage which Inergi is to undertake. Inergi is required to provide termination transition services until such time as Networks no longer requires such services up to a maximum of 18 months following the expiry date of the Current Agreement. The latest end date for transition services is September 1, 2016. Base Services will continue at the agreed upon rates, and "transition services" will be provided, in parallel, on a time-and-materials basis.

3.0 RETURNING TO MARKET

To prepare for the Current Agreement's expiry on February 28, 2015, a project to re-tender the services in scope for the Current Agreement commenced in late 2012. The project is referred to internally as the Outsourcing Agreement Re-tendering (OAR) project. Networks has retained Information Services Group Inc. as an external advisor to assist the company through the process. Osler, Hoskin and Harcout LLP ("Oslers") have been retained as external counsel.

Multiple factors are shaping Networks' foray back into the marketplace. The outsourcing market has changed significantly since services under the Original Agreement commenced in 2002; shorter term contracts and multi-supplier environments are the norm. Networks anticipates that its next outsourcing arrangement will reflect this new commercial reality. Overall Networks seeks a new contract(s) which reflects market-based pricing, an improved service delivery model, flexibility for Networks, support of and access to new technologies and delivery of value to its customers and shareholder.

A governance structure has been established to monitor the OAR project and execute decisions throughout the process. The OAR project team is comprised of representatives from lines of business, the Outsourcing Services Department, Information Services Group, Inc. and internal and external legal counsel. The OAR project team meets on a weekly basis to review status of the project. The project team is governed by a Steering Committee which includes senior management from the affected lines of business, the Executive Committee and the Board of Directors. On a quarterly basis, the project director reports on the OAR project's progress to all of the committees noted above. The procurement process for the OAR project is being monitored by Internal Audit to ensure that the process is fair and transparent. To date, Internal Audit has determined that the process has been compliant.

Networks has structured its OAR project into three phases: Phase 1 (Development of Strategy and Commercial Documents); Phase 2 (Supplier Selection and Contract); and Phase 3 (Transition). These phases are detailed below.

3.1 Phase 1 – Development of Strategy and Commercial Documents

Any outsourcing arrangement must allow Networks to focus on its core businesses and meet its strategic objectives. Networks is considering all market options and risks associated with contract length and number of suppliers. Senior management explored the risks associated with the outsourcing strategy at two workshops, one held in December 2012 and another held in April 2013. The key risks discussed at these workshops were (a) the possibility of an inadequate response from the market, (b) the complexity of managing a multi-supplier environment, (c) challenges in transitioning to the successful supplier(s), and (d) possible claims by unsuccessful proponents that the procurement process was not fair and transparent. Key mitigation strategies that Networks has employed to minimize these risks are actions such as engaging outsourcing advisors, communicating openly and frequently with potential suppliers, requiring potential suppliers to address transition challenges, and having Internal Audit conduct an independent review of the procurement process. The risks are reviewed at the various committees within the governance structure on an ongoing basis to ensure that mitigation is occurring and is effective.

With the results of the workshops and guidance from external advisors and lines of businesses, the outsourcing strategy was developed. The strategy is based on the following key objectives:

(a) continually improve value received for money spent;
(b) reflect current global best practices in the outsourced services;
(c) ensure effective and robust performance management and governance; and
(d) maximize Networks' flexibility to adjust volumes and scope of work and the technology employed to perform it.

All of these objectives reflect Networks' commitment to continuous improvement in productivity which should drive its overall operational and cost effectiveness. The last objective also provides Networks the flexibility to respond to customer preferences, which may change over time.

This phase involved formulating clear expectations for the next outsourcing contract(s), including a contract term of 5 years with 2 one-year extensions at Networks' option. These expectations have been clearly articulated through the key elements of the outsourcing strategy:

a) multi-source different service offerings;

b) issue a Request for Pre-qualification (“RFPQ”) to pre-qualify suppliers and gather market intelligence over “bundling” of services offerings in preparation for a Request for Proposal (“RFP”);
c) issue a RFP to pre-qualified suppliers to down select and negotiate terms and conditions; and
d) request Board of Director approval over new contract(s).

In early 2013, the Board of Directors approved the above outsourcing strategy.

The introduction of a multi-supplier environment would require a new governance structure to monitor and measure the outcomes of the outsourcing contract(s). In this phase, the project team developed a working service integration and management model (“SIAM”). SIAM would coordinate and oversee the performance of the outsourced services in a multi-supplier arrangement. This function will specify the processes and procedures to be implemented across all of the suppliers and as well ensures adherence by all suppliers. A multi-supplier arrangement may result in some SIAM work being outsourced under a separate competitive process.

Other considerations in formulating the outsourcing strategy is the Shareholder Declaration and Resolution (the “2013 Directive”) dated September 30, 2013 issued in October 2013. The 2013 Directive restricts Hydro One Inc.’s Board of Directors regarding new procurements for provision of services set out in the Current Agreement upon expiration of the agreement. The Minister of Energy exercised those powers to require such services be performed by persons who are employed in Ontario to perform those services and physically located in Ontario at that time they perform those services. A copy of the 2013 Directive is attached to this exhibit as Appendix C.

The strategy was further impacted by the Power Worker's Union grievance challenging Networks' ability to seek another supplier to perform the outsourced services through a competitive process filed on March 25, 2013. On December 10, 2013 a settlement was reached between Networks and the Power Worker's Union. The settlement requires the RFP to be amended such that, all pre-qualified proponents, as a condition of being permitted to respond, agree to voluntarily recognize the Power Worker's Union as the bargaining agent for the work and to enter into a Memorandum of Agreement prior to responding to the RFP. A completed collective agreement must be executed before the work commences. Networks has also extended this settlement to the Society of Energy Professionals.

The RFPQ was designed to screen possible suppliers based on certain evaluation criteria and to gather market intelligence on potential bundling options for the outsourced services. The RFPQ was issued in February 2013. It made no commercial commitments to any suppliers. As part of the evaluation process, the responses were reviewed and suppliers were selected to give oral presentations. Upon completion of the evaluation of the written responses and oral presentations, suppliers were pre-qualified to receive the RFP.

Networks held a common executive alignment session simultaneously with all pre-qualified suppliers where Executive Management delivered key common messages. Executive alignment sessions were also held individually with pre-qualified suppliers to provide feedback on the responses to the RFPQ and to solicit input on the bundles. Networks also met individually with the pre-qualified suppliers in discovery sessions to scope out the terms of reference and the bundles for the RFP. These activities were key in developing the RFP documents to ensure a competitive market response.

Based on the responses to the RFPQ, the project team developed a RFP which provisionally divided the outsourced services into four bundles of work. The proposed bundles were reviewed with senior management at a third risk workshop held in mid-2013. In the RFP, Networks' management has retained the right to re-bundle services based on market response to the RFP. Through the RFPQ process, the project team also determined that SIAM could be covered in a subsequent RFP once the supplier landscape has been determined.

With the Board of Directors' approval, the RFP was issued in November 2013 to pre-qualified suppliers.

3.2 Phase 2 – Supplier Selection & Contract Negotiations

In early December 2013, the project team held individual discovery sessions to provide the pre-qualified suppliers with an opportunity to seek clarification regarding the RFP. Responses to the RFP are anticipated by February 18, 2014. Once the written responses are reviewed, pre-qualified proponents will be short-listed to give oral presentations sometime in March or April 2014. Following these presentations, the pre-qualified supplier submissions and oral presentations will be evaluated, and finalists will be selected in late April 2014 to proceed to negotiate business terms. The project team will then make a final business recommendation. The project team anticipates that Networks will enter into final contract negotiations in June 2014, and final contract(s) will be approved by the Board of Directors in August 2014.

3.3 Phase 3 – Transition

Once the supplier(s) have been selected, the next step will be to transition to the successful supplier(s). Networks will establish a project management office that will govern the overall transition and ensure that all accountable parties are performing the activities as agreed to in the transition plans of the successful suppliers and the incumbent's termination transition plan. The project management office will also monitor the transition risks to ensure that they have been mitigated through this phase. The key elements in this phase include:

a) migration of workload;
b) migration of services;
c) knowledge transfer; and
d) historical data transfer.

There will be costs associated with all of these transition activities for all of the parties in this phase. As well, the costs related to delivery of services under the Current Agreement throughout the transition phase will continue to be incurred.

Appendices

Appendix A – Base Services outsourced under the Current Agreement
Appendix B – Fees (Historical, Bridge and Test Years)
Appendix C – 2013 Directive

Appendix A: Base Services Outsourced under the Current Agreement		
SOW	**Domain**	**Service Description**
Information Technology Services	Infrastructure Operations	Services that are required by the user community and that facilitate the operation of shared devices and servers on a corporate level as well as the Services required to engineer and manage the computing network infrastructure.
	End User Support	IT Service Desk and Desktop Support
	Application Development and Maintenance	Services to provide technology platform, operational, quality control and application support services customized to the service requirements and needs of the application.
	Cross Functional Services	Provides general service functions to all other IT domains, including Service Management, Asset Management, Resource Management and Quality Assurance. Services also include project-related responsibilities for all IT domains.
Customer Service Operations[1]	Inbound Call Contact Handling	Provides customer call handling services for billing, customer services, collections, outages and emergencies for residential and small business segment. It includes corporate switchboard, maintain the day-to-day operational configuration of the Interactive Voice Response system, and responding to other contacts such as letters and email.
	Bill Production	Issue electricity bills, including bill print, insert delivery to Canada Post and remittance, managing exceptions, accuracy and timely delivery. Maintain accuracy of customer billing records to enable timely and accurate billing and print, envelope and dispatch bills to Canada Post.
	Credit and Collections	Manage the collection of outstanding customer debts and negotiate and collect deposits.
	Business Customer Centre	Selection of services for business customers, including inbound call and contact handling, retail settlements, billing exceptions and manual bills. Also handle contacts regarding Asset Tampering and Measurement Canada Requests.

[1] Inergi subcontracts the performance of all customer service operations to Vertex Customer Management (Canada) Limited ("**Vertex Canada**"), a wholly-owned subsidiary of Vertex Data Science Limited, a UK-based business process outsourcing company which is held by a consortium of US-based private equity firms.

SOW	Domain	Service Description
	Business Support and Sustainment	Provide business support and analysis service pertaining to all business processes, applications, and interfaces related to CSO services, which include day-to-day management and resolution of Break / Fix issues, bill channel changes, and regulatory changes.
	Cross-Functional	Provide the following in support of all other CSO domains: • Business process support • Training and communications • Courier and mailroom service • Forecasting • Quality monitoring and assurance • Continuous improvement • Performance reporting • Audits • Maintain quality standards • Incident notification • Implement small discretionary business changes
Settlements		Wholesale Settlements – Provide settlement and reconciliation services for power procured from the Independent Electricity System Operator and embedded Retail Generators with due consideration to legislative initiatives for fixed energy prices for low volume customers, transmission revenues and inter-utility load transfers, and cost of power reporting. Retail Settlements – Provide complex billing for interval meter accounts.
Source to Pay	Procurement & Sourcing	Maintain market intelligence of applicable commodities, source commodities and services, manage and develop supply strategies (strategic sourcing), process purchase transactions, monitor spend on all commodities and services.
	Process & Quality	Services supporting the execution of daily transactions, maintenance and development of job aids, training, provision of audit files for compliance, quality checks and records management.
	Customer Support	Provision of Order Desk, expediting services, inspection services, general inquiries and transportation.
	Systems Support & Reporting	Provision of support systems, statistical and data reporting.
	Accounts Payable (AP)	Services required for processing disbursements which include: invoice processing, payments management, AP inquiries support, period-end reconciliations, management reporting and special projects.

SOW	Domain	Service Description
Payroll	Pay Operations	Services necessary to calculate all pay cycles, remit pay to all staff and pensioners, remit deductions to the appropriate authorities and organizations, and to provide appropriate supporting documentation and filing systems.
	Payroll Accounting	Services necessary to account for the pay cycles and to provide appropriate supporting documentation.
	Inquiries and Application Support	Services necessary to support Pay Operations and Payroll Accounting Domains, including tool support and issue resolution.
	Contingencies	Includes responsibilities to deal with eventualities which disrupt pay, such as system outages and inclement weather.
Finance and Accounting Services	General Accounting	General Accounting – ensuring financial recognition consistent with corporate requirements, accounting adjustments, processing of transactions, and support of financial systems.
	Non-Energy Billing Accounts Receivable (AR)	Services required for processing non-energy miscellaneous billings and AR which include: customer invoicing, customer collections support, applying AR payments and adjustments, AR inquiries support, period end and reconciliation, and management reporting.
	Fixed Assets	Provides fixed assets and project costing transaction processing, transfer of projects to fixed assets, recording sales and retirement of assets, minor fixed assets inventory certification, and depreciation analysis.
	Financial Planning and Analysis	Provide advice, guidance, consultation and project support on routine operating processes and business support initiatives for areas such as Regulatory Accounting, Primary Revenue and Cost of Power, Actuarial Support, and Planning and Budgeting.
	Cross Domain Accounting	Provision of Centre of Excellence for analysis and reconciliation of general ledger accounts ensuring appropriate financial recognition according to corporate and legislative requirements. Also support and analysis for accounts that cross into other domains e.g. Vendor Master, Material Master, and Fixed Assets.

Table 1 - Summary of Fees ($ Million)

	Historic				Bridge	Test				
Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Fees for Base Services	$ 133.32	$ 140.18	$ 134.19	$ 128.29	$ 116.91	$ 116.55	$ 112.86	$ 109.17	$ 109.42	$ 109.69
Volume, Scope & Other	$ 2.57	$ 2.17	$ 10.30	$ 13.14	$ 10.82	$ 5.12	$ 4.46	$ 4.52	$ 4.74	$ 4.96
COLA	$ 3.98	$ 1.33	$ 3.57	$ 6.42	$ 10.72	$ 12.34	$ 14.35	$ 17.02	$ 20.02	$ 23.60
Subtotal Fees for Base Services	**$ 139.86**	**$ 143.68**	**$ 148.06**	**$ 147.85**	**$ 138.45**	**$ 134.01**	**$ 131.67**	**$ 130.71**	**$ 134.18**	**$ 138.25**
Project Spend (all LOB's)	$ 18.44	$ 34.69	$ 52.00	$ 49.66	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15	$ 30.15
Total Payments	**$ 158.30**	**$ 178.37**	**$ 200.06**	**$ 197.51**	**$ 168.60**	**$ 164.16**	**$ 161.82**	**$ 160.86**	**$ 164.33**	**$ 168.40**

Table 2 - Allocation of Fees to Distribution ($ Million)

	2015	**2016**	**2017**	**2018**	**2019**
Finance and Accounting	$ 3.13	$ 3.03	$ 2.94	$ 3.01	$ 3.10
Payroll	$ 1.77	$ 1.72	$ 1.67	$ 1.71	$ 1.76
Information Technology Services	$ 40.75	$ 39.74	$ 38.89	$ 39.88	$ 41.05
Accounts Payable	$ 1.28	$ 1.24	$ 1.19	$ 1.21	$ 1.24
Settlements	$ 3.92	$ 4.15	$ 4.37	$ 4.61	$ 4.84
Customer Service Operations	$ 34.09	$ 34.09	$ 35.11	$ 36.07	$ 37.21
Subtotal Fees for Base Services	**$ 84.94**	**$ 83.97**	**$ 84.18**	**$ 86.50**	**$ 89.19**
Project Spend (all LOB's)	$ 25.77	$ 25.77	$ 25.77	$ 25.77	$ 25.77
Total Payments	**$ 110.71**	**$ 109.74**	**$ 109.95**	**$ 112.27**	**$ 114.96**

Schedule B

Ministry of Energy

Office of the Minister

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Ontario

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Mr. Carmine Marcello
President and CEO
Hydro One Inc.
483 Bay Street
North Tower, 15th Floor
Toronto ON M5G 2P5

Dear Mr .Marcello:

I am writing to advise you that I am exercising my powers as the Sole Shareholder of Hydro One Inc. to require that all new procurements by Hydro One Inc. for work currently being done by Inergi LP under its existing outsourcing agreement with Hydro One Inc. include a requirement that the work be performed in Ontario by persons employed and residing in Ontario.

Thank you for your prompt attention to this matter.

Sincerely,

Bob Chiarelli
Minister

HYDRO ONE INC.
RESOLUTION OF THE SOLE SHAREHOLDER ("RESOLUTION")
EXERCISING THE RESTRICTED POWERS OF THE DIRECTORS UNDER A UNANIMOUS SHAREHOLDER AGREEMENT

REGARDING OUTSOURCING OF SERVICES COVERED BY THE INERGI MASTER SERVICES AGREEMENT

BACKGROUND:

A. Her Majesty the Queen in right of the Province of Ontario, as represented by the Minister of Energy (the "**Shareholder**") is the sole shareholder of Hydro One Inc. (the "**Corporation**").

B. The Corporation entered into an Inergi Master Services Agreement with Inergi LP dated December 28, 2001, as extended as of May 1, 2010 (the "**Outsourcing Agreement**").

C. Under the Outsourcing Agreement, Inergi LP agreed to perform a range of services for the Corporation, as more particularly set out in or contemplated under the Outsourcing Agreement (the "**Outsourced Services**").

D. By way of a declaration made as of September 24, 2008 pursuant to section 108 of the *Business Corporations Act* (Ontario) (the "**OBCA**"), the Shareholder declared that, as of that date, the powers of the directors of the Corporation:

(a) to make any and all decisions in respect of the offshoring of jobs under, or in relation to any provision of, the Outsourcing Agreement, as well as any ancillary or related agreements, including any and all decision-making power with respect to any provision in the Outsourcing Agreement, including any ancillary or related agreement, that could result in or has resulted in the offshoring of jobs; and

(b) to determine any and all matters in respect of or elements in relation to reimbursement or compensation to Inergi regarding steps taken or work done or expenditures incurred by it to date with respect to the offshoring of jobs under the Outsourcing Agreement, including any and all ancillary or related agreements;

were thereby removed from the directors and resided solely with the Shareholder.

E. The Corporation is contemplating undertaking one or more procurements for the provision of the Outsourced Services once the Outsourcing Agreement expires (the "**New Procurements**").

F. Pursuant to section 108 of the OBCA, the Shareholder made a declaration as of the date of this Resolution (the "**Declaration**") that restricted the discretion and powers of the directors of the Corporation (the "**Directors**") to manage or supervise the management of the business and affairs of the Corporation, as they pertain to whether or not the New Procurements should include a requirement (the "**Ontario Requirement**") that all Outsourced Services be performed by persons who are:

(a) employed in Ontario to perform those Outsourced Services, and

(b) physically located in Ontario at the time they perform those Outsourced Services,

(the "**Restricted Powers**").

G. The Declaration is deemed to be a unanimous shareholder agreement under subsection 108(3) of the OBCA (the "**Unanimous Shareholder Agreement**").

NOW THEREFORE, exercising the Restricted Powers assumed from the Directors through the Unanimous Shareholder Agreement, the Shareholder makes the following resolution pursuant to section 129 of the OBCA:

1. All New Procurements shall include the Ontario Requirement.

2. For greater clarity, the resolution in paragraph 1 does not impose any specific requirements with respect to the implementation of that resolution. Accordingly, the resolution does not restrict the discretion and power of the Directors to determine the manner in which the resolution is implemented.

3. This Resolution shall be governed by the laws of the Province of Ontario and the laws of Canada applicable in that Province.

IN WITNESS OF THE FOREGOING the Shareholder has duly executed this Resolution as of **September** 30, **2013** (the "**Effective Date**").

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO, AS REPRESENTED BY THE MINISTER OF ENERGY

By: ______________________
Bob Chiarelli
Minister of Energy

HYDRO ONE INC.
DECLARATION OF THE SOLE SHAREHOLDER ("DECLARATION")

REGARDING OUTSOURCING OF SERVICES COVERED BY THE INERGI MASTER SERVICES AGREEMENT

BACKGROUND:

A. Her Majesty the Queen in right of the Province of Ontario, as represented by the Minister of Energy (the "**Shareholder**") is the sole shareholder of Hydro One Inc. (the "**Corporation**").

B. The Corporation entered into an Inergi Master Services Agreement with Inergi LP dated December 28, 2001, as extended as of May 1, 2010 (the "**Outsourcing Agreement**").

C. Under the Outsourcing Agreement, Inergi LP agreed to perform a range of services for the Corporation, as more particularly set out in or contemplated under the Outsourcing Agreement (the "**Outsourced Services**").

D. By way of a declaration made as of September 24, 2008 pursuant to section 108 of the *Business Corporations Act* (Ontario) (the "**OBCA**"), the Shareholder declared that, as of that date, the powers of the directors of the Corporation:

(a) to make any and all decisions in respect of the offshoring of jobs under, or in relation to any provision of, the Outsourcing Agreement, as well as any ancillary or related agreements, including any and all decision-making power with respect to any provision in the Outsourcing Agreement, including any ancillary or related agreement, that could result in or has resulted in the offshoring of jobs; and

(b) to determine any and all matters in respect of or elements in relation to reimbursement or compensation to Inergi regarding steps taken or work done or expenditures incurred by it to date with respect to the offshoring of jobs under the Outsourcing Agreement, including any and all ancillary or related agreements;

were thereby removed from the directors and resided solely with the Shareholder.

E. The Corporation is contemplating undertaking one or more procurements for the provision of the Outsourced Services once the Outsourcing Agreement expires (the "**New Procurements**").

F. Pursuant to section 108 of the OBCA, the Shareholder wishes to:

(a) restrict the discretion and powers of the directors of the Corporation (the "**Directors**") to manage or supervise the management of the business and affairs of the Corporation, as they pertain to whether or not the New Procurements should include a requirement (the "**Ontario Requirement**") that all Outsourced Services be performed by persons who are:

(i) employed in Ontario to perform those Outsourced Services, and

(ii) physically located in Ontario at the time they perform those Outsourced Services,

(the "**Restricted Powers**"); and

(b) exercise the Restricted Powers in order to determine whether or not the Ontario Requirement is to be included as part of the New Procurements.

NOW THEREFORE the Shareholder makes the following declaration pursuant to section 108 of the OBCA, intending the same to be deemed to be a Unanimous Shareholder Agreement within the meaning of the OBCA:

1. The Restricted Powers are hereby restricted and no longer reside with the Directors, and are hereby assumed by the Shareholder, from and after the Effective Date (as defined below), until this Declaration is amended or revoked.

2. By assuming the Restricted Powers, the Shareholder assumes, pursuant to section 108 of the Act, all of the rights, powers, duties and liabilities of the Directors to manage or supervise the management of the business and affairs of the Corporation in respect of the exercise of the Restricted Powers, and pursuant to subsection 108(5) of the Act the Directors are relieved of their duties and liabilities to the same extent.

3. For greater clarity, the restriction and assumption of the Restricted Powers as contemplated above does not restrict the rights, powers, duties and liabilities of the Directors to manage, or supervise the management of, the business and affairs of the Corporation relating to the actual implementation of any decisions made by the Shareholder in its exercise of the Restricted Powers.

4. This Declaration shall be governed by the laws of the Province of Ontario and the laws of Canada applicable in that Province.

IN WITNESS OF THE FOREGOING the Shareholder has duly executed this Declaration as of **September** 30, **2013** (the "**Effective Date**").

HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF ONTARIO, AS REPRESENTED BY THE MINISTER OF ENERGY

By: ______________________

Bob Chiarelli
Minister of Energy

COMMON CORPORATE FUNCTIONS AND SERVICES AND OTHER OM&A

1.0 OVERVIEW

Hydro One Networks has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These costs are referred to as Common Corporate Functions and Services ("CCFS"). Included in this exhibit is a discussion of CCFS costs and activities as well as Other OM&A which is comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.

2.0 COMMON CORPORATE FUNCTIONS AND SERVICES

Table 1 presents, for comparison purposes, the total Common Corporate Functions and Services ("CCFS") costs over the Historic, Bridge and Test years as well as the 2015 to 2019 Hydro One Distribution allocation amounts.

Table 1

Total 2010 - 2019 CCFS Costs and 2015 - 2019

Allocation to Distribution ($ Millions)

Description	**Historic Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Corporate Management	5.0	5.1	5.0	4.9	5.3	5.4	5.4	5.4	5.5	5.5	2.4	2.4	2.4	2.4	2.4
Finance	31.4	31.9	35.2	43.2	45.0	44.6	43.8	43.0	42.7	43.6	18.0	17.6	17.3	17.2	17.6
Human Resources	16.4	11.0	9.9	11.8	13.1	13.0	12.2	12.1	12.3	12.4	5.7	5.4	5.4	5.4	5.5
Corporate Communications & Services	9.6	8.7	11.3	14.2	13.9	12.6	12.6	12.7	12.8	12.9	6.6	6.6	6.6	6.7	6.7
General Counsel and Secretariat	7.5	7.4	8.8	10.0	10.1	10.2	10.2	10.2	10.4	10.5	4.1	4.1	4.2	4.2	4.2
Regulatory Affairs	21.3	20.1	20.6	22.0	24.1	21.5	22.4	21.6	23.3	22.9	12.0	12.4	12.1	13.2	12.9
Security Management	2.4	3.0	3.1	3.7	4.8	4.8	4.6	4.6	4.7	4.8	2.5	2.4	2.4	2.4	2.5
Internal Audit	2.8	3.1	3.5	3.7	3.6	3.6	3.6	3.6	3.7	3.8	1.1	1.1	1.1	1.2	1.2
Real Estate & Facilities	49.9	51.6	54.6	56.8	60.2	61.4	61.3	62.4	63.8	66.2	24.8	24.7	25.2	25.8	26.8
Total CCF&S Costs	**146.3**	**141.9**	**152.0**	**170.2**	**180.1**	**177.1**	**176.1**	**175.6**	**179.2**	**182.6**	**77.2**	**76.8**	**76.7**	**78.6**	**79.9**

Total CCFS costs increased by $6.9 million from 2013 to 2015 primarily due to the following factors: higher Real Estate costs for additional work space as a result of the growth in the company's work program, increased Finance costs as a result of additional work functions being transferred to the Corporate Controller group previously in other groups and higher Corporate Security and Human Resource expenses. These increases are partially offset by decreased costs related to Outsourcing Contract Management and Regulatory Affairs.

From 2015 to 2016, total CCFS costs decrease by $1.0 million primarily due to decrease in Finance and Human Resource costs.

From 2016 to 2017, total CCFS costs decrease by $0.5 million decreased in Finance and Regulatory Affair costs, partially offset by higher Real Estate expenses.

From 2017 to 2018, total CCFS costs increase by $3.6 million primarily due to increased Regulatory Affairs costs and Real Estate expenses.

From 2018 to 2019, total CCFS costs increase by $3.4 million mostly as a result of increased Real Estate expenses and Finance costs.

Details on costs and work in each CCFS function are provided in the following sections.

2.1 Corporate Management

The following Table 2 provides a summary of Corporate Management costs:

Table 2
Corporate Management Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	5.0	5.1	5.0	4.9	5.3	5.4	5.4	5.4	5.5	5.5	2.4	2.4	2.4	2.4	2.4

Corporate Management represents those functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Chief Executive Officer ("CEO"), Treasurer's Office, Chief Financial Officer ("CFO") and General Counsel and Corporate Secretariat.

The General Counsel and Corporate Secretariat function provides advice and support to the Board of Directors and Corporate Officers. It provides advice and training, reports on Code of Conduct, reports on activities related to the *Freedom of Information and Privacy Act* (Ontario) as well as the *Personal Information Protection & Electronic Documents Act* (Canada).

The CFO is responsible for overseeing the finance function and for reporting information to Hydro One Inc.'s subsidiaries, regulators, investors and the shareholder. This includes reviewing and approving financial and investment decisions, business and strategic plans and ensuring the integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

The allocation of the costs associated with the activities of Corporate Management are governed by service level agreements between Hydro One Inc. ("HOI"), Hydro One

Networks and their affiliates as outlined in Exhibit A, Tab 11, Schedule 3. This exhibit also describes the activities performed by HOI, Hydro One Networks and the amounts allocated to the various subsidiaries.

2.2 Finance

Table 3 provides a summary of finance costs.

Table 3
Finance Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	31.4	31.9	35.2	43.2	45.0	44.6	43.8	43.0	42.7	43.6	18.0	17.6	17.3	17.2	17.6

2.2.1 Overview

Finance provides strategic advice and services related to planning, processing, recording, reporting and monitoring all financial transactions taking place within the organization. Clients include parties which are both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controller;
- Corporate Tax; and
- Treasury.

2.2.2 Corporate Controller

The Corporate Controller provides leadership and direction regarding all business planning, performance management, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles.

This function oversees the development of actual and forecast financial information and manages reporting processes for appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company on internal control matters, employing measures such as "organization authority registers" and financial policies and procedures. It also provides leadership on compliance with Ontario securities laws, including Bill 198, and the Multi-Jurisdictional Disclosure System ("MJDS") rules for a foreign-issuer registered with the U.S. Securities Exchange Commission ("SEC").

The Corporate Controller function is responsible for establishing and leading the annual business planning and budgeting processes and for presenting the plan to the Board of Directors and the Provincial Government. This function is also responsible for developing and leading strategies and plans that support corporate goals related to the transmission and distribution businesses. This involves conducting special studies in areas like corporate performance, including reliability performance, benchmarking, work program performance, productivity, and cost savings management. Lastly, the Corporate Controller function performs services such as business case review, business valuation, transaction support, and develops and maintains financial models and provides analytical support for a variety of financial planning and reporting processes.

Many routine financial services are outsourced to a third party supplier, such as accounts payable, accounts receivable, fixed asset accounting, general accounting, planning budgeting and reporting support, pension support, human resources pay services and a number of administrative procedures. The costs of these services comprise a major portion of the Corporate Controller costs.

The total cost of Corporate Controller activities in the test years is as follows: In 2015, $37.9 million; in 2016, $37.0 million; in 2017, $36.2 million; in 2018, $35.8 million; and in 2019, $36.7 million. The portion allocated to Hydro One Distribution is $15.4 million in 2015, $15.0 million in 2016, $14.7 million in 2017, $14.6 million in 2018 and $14.9 million in 2019.

Corporate Controller costs increased by $8.5 million in 2013 and a further $0.9 million in 2014, mainly due to the addition of certain functions to the Corporate Controller organization made after company filed its transmission rate application EB-2010-0002. In 2013, additional functions were added to the Corporate Controller organization: the performance reporting functions previously included in the Business Performance category within Asset Management, and the Time Reporting Centre and Corporate Charge Card Compliance functions previously included in work program costs. In 2014, Work Management and Project Accounting Specialists will also be moved to the Corporate Controller's organization. These transfers were made to better align the finance function within the Corporate Controller organization. For the years 2016 to 2018, costs are expected to decrease due to process streamlining, productivity improvements and a decline in outsourcing fees.

2.2.3 <u>Corporate Tax</u>

Corporate Tax manages the tax affairs (compliance, audits and planning), for each taxable entity within the Hydro One group of companies. This includes corporate income taxes, harmonized sales tax (previously, goods and services tax and provincial sales tax), debt retirement charge, payroll and non-resident withholding tax, and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met. Moreover, Corporate Tax provides tax consulting services to other departments with respect to mergers and acquisitions activities, payroll tax, taxable benefits, agreements, financing, and all transactions and information about tax costs for regulatory purposes.

The costs associated with Corporate Tax activities are $2.4 million between 2015 to 2019, with $0.9 million being charged to Distribution annually.

2.2.4 Treasury and Risk

Total annual treasury costs are $6.5 million in 2015, $6.6 million in 2016 and 2017, and $6.8 million in 2018 and 2019. Of these amounts, $2.7 million for 2015 and 2016 and $2.8 million for 2017 to 2019, inclusive, represent annual costs incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, banks and debt covenants;
- manage the company’s daily liquidity position, control cash and manage the company’s bank accounts;
- settle all transactions and manage the relationship with creditors;
- communicate with debt investors, banks and credit rating agencies;
- develop business risk management policies, frameworks and processes;
- introduce and promote new techniques for assisting management to identify and evaluate risks within operations;
- prepare corporate risk assessments; and
- maintain a framework of key business risks.

A portion of the Treasury budget is recovered through the cost of long-term debt, as stated in Exhibit B1, Tab 2, Schedule 1.

The remaining $3.7 million for 2015, $3.8 million for 2016, $3.9 million for 2017 and $4.0 million for 2018 and 2019 include costs relating to risk assessment, the negotiation and purchase of insurance policies, and claims management and settlement. These costs cover premiums paid for corporate shared services insurance coverage, including third party liability, fiduciary liability, and directors and officers insurance. They also include the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles. The cost of other insurance coverage is paid for and reported by the lines of business to whom the coverage is applicable.

Hydro One Distribution accounts for $1.7 million of the $3.7 million Treasury budget for 2015, $1.7 million of the $3.8 million budget for 2016, $1.7 million of the $3.9 million budget for 2017, and $1.8 million of the $4.0 million budget for each of 2018 and 2019.

Table 4 shows the premiums for all of Hydro One Inc.'s insurance policies and the cost of self-insurance for the 2010 to 2019 period. Self-insurance costs for the 2015 to 2019 period take into consideration the company's risks exposures, the long-term historical claims experience, the deductible on the liability policies and the costs of insuring the self-insured exposures. The main driver for self-insurance costs are claims by third parties which can fluctuate from year to year.

Table 4
Hydro One Inc. Insurance Costs ($ Millions)

Description	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Premiums paid for Corporate Functions and Services Insurance Policies *	1.2	1.2	1.3	1.5	1.7	1.8	1.8	1.9	2.0	2.0
Self-insurance Cost	1.1	0.8	3.2	1.9	2.0	2.0	2.0	2.0	2.0	2.0
Total	**2.3**	**2.0**	**4.5**	**3.4**	**3.7**	**3.7**	**3.8**	**3.9**	**4.0**	**4.0**

*****The cost of other insurance coverage is captured and reported by the lines of business where the coverage is applicable.

2.3 Human Resources – "People & Culture"

Table 5 provides a summary of Human Resources costs:

Table 5
Human Resources Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	16.4	11.0	9.9	11.8	13.1	13.0	12.2	12.1	12.3	12.4	5.7	5.4	5.4	5.4	5.5

Early in 2013, the Human Resources function was renamed "People and Culture" ("P&C") to highlight, in part, the importance of employees and the cultural transformation that Hydro One Networks is undertaking.

The P&C function exists to ensure that Hydro One Networks has the policies, systems and programs to attract, manage, engage and retain a high performing workforce to execute the corporate strategy. P&C provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits services, and labour relations services.

One of the greatest challenges facing Hydro One Networks is in an area where P&C will be expected to play a significant role – the dramatic demographic transition that will be occurring in the company's workforce over the next few years. In December 31, 2013, approximately 1,000 active staff members (serving both transmission and distribution businesses) were eligible for undiscounted retirement. The number of employees eligible to retire continues to grow, and the uptake in retirement is growing. Based on employee data today, over 2000 employees will be eligible to retire by 2019. Retirement-eligible employees opting to retire increased by 16% between the period 2011 and 2012, and retirement rates for 2013 continue to show an increase in employees electing to retire.

2.3.1 Human Resource (HR) Operations

Hydro One Networks' HR Operations provide advice and guidance to managers, supervisors, and employees on a myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. In addition to general HR consulting, HR Operations also performs a number of 'specialist' support/service activities. The Pension and Benefits Section within HR Operations administers the Hydro One pension plan for approximately 7,100 pensioners. In addition, this Section also administers the benefits programs for all employee groups.

2.3.2 Talent Management

This P&C function recommends and administers policy in areas related to external hiring and leadership development. In addition, it manages all of Hydro One Networks' management/leadership development activities, including the assessment of high-potential succession candidates and miscellaneous specialized one-off hiring initiatives, as required.

2.3.3 Recruitment Solutions & Diversity

This function manages Hydro One Networks' principal[1] cyclical hiring and on-boarding processes - the New Graduate, the Co-Op Student, Internship and Developmental Student Programs, and the Summer Student Hiring Program. Additionally, this function is accountable for managing Hydro One's Two-year New Grad Training and Development

[1] Trades staff are hired through the Power Workers' Union Hiring Hall processes.

Program and implementing the company's Diversity Plan, which includes Aboriginal recruitment and the Women in Leadership Program.

2.3.4 Compensation & Benefits

This function manages compensation, benefits, reporting and master data for all Hydro One Networks' employees and pensioners by ensuring the accurate application, record-keeping and security of all such information. The Compensation and Benefits Group also provides regular, strategic reporting to senior management on HR and pay data on topics such as retirement demographics, headcount, overtime reports, data for OEB submissions, etc., as well as participating in industry wide compensation, benefit and pension surveys. The same group also manages the Short Term Incentive for management's compensation.

2.3.5 Labour Relations

Labour Relations provides advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. The company is a party to twenty-four collective agreements and a number of mid-term agreements and letters of understanding. Labour Relations is responsible for negotiating and administering all such agreements and letters of understanding. In addition, the company must comply with legislation, such as the *Ontario Labour Relations Act*, the *Employment Standards Act* (Ontario), the *Human Rights Code* (Ontario), etc., all of which require interpretation to advise managers.

2.3.6 HR Productivity Initiatives

Continuous improvement is a core value at Hydro One Networks. Within the P&C function, there have been a number of initiatives to enhance productivity:

- The Human Resources/Payroll Transformation Project commenced in late 2013. This project will build further on the SAP platform and the SuccessFactors processes and technology to automate a number of talent management processes including, performance management, succession and career development, compensation management, recruitment management, and to update the company's current learning management system.
- The automation of Hydro One Networks' performance management process will improve the quality of the information available to managers regarding their staff, provide transparency and consistency in creating goals and assessing performance, provide the ability to calibrate performance, improve the ease of accessing this information, and provide reporting and trending information that currently does not exist because the process is manual.
- The Pension Administration Team is outsourcing additional transactional tasks that are currently completed by the pension analysts. This will allow the team to focus on more strategic pension issues and improve service and communication to plan members. The goal is to reduce costs to the pension plan, increase pension awareness and mitigate risk on the transactional items.
- HR Operations and Labour Relation have been merged under P&C, which creates an opportunity to leverage relationships throughout the organization to drive the desired cultural transformation and leverage natural synergies between these two groups.
- The creation of new reports will improve reporting, making information more accessible for managers as required. This will reduce the number of *ad hoc* requests, which will reduce the transactional work required by the P&C Reporting Group,

permit them to focus on more strategic and analytical work, and improve their ability to respond to urgent requests (such as requests from the OEB or the Hydro One Board of Directors).

- A pensioner website is being developed that will provide external access to required information for pensioners. This will reduce the basic transactional work stemming from calls from pensioners. This will also reduce the cost of mailing printed materials to pensioners.
- P&C re-branded its existing internal website and launched a new "People Matters" internal website, with emphasis being placed on better and more up-to-date information, new tools and better search capabilities. Making this information available on the internal website will reduce basic transactional work for P&C staff and will provide more detailed and consistent information for the company's staff members, generally.
- P&C will automate some master data transactions, using SAP technology, which will permit managers to complete HR transactions online, capturing data once at its source.
- The vacancy management process has moved from a paper-based format to an electronic format. Files that were once stored in paper hardcopy are now stored electronically, allowing for quick and easy management of the information.
- A new recruitment consultant was selected in 2013. The new consultant will assume many of the administrative duties currently done by P&C's internal recruitment consultants. This will allow the internal recruitment consultants to focus on more strategic or relationship-building activities instead of simply processing paperwork. The goal is to improve customer service and decrease the administrative aspect of the job.

2.4 Corporate Communications

Table 6 provides a summary of Corporate Communications costs.

Table 6
Corporate Communications Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	9.6	8.7	11.3	14.2	13.9	12.6	12.6	12.7	12.8	12.9	6.6	6.6	6.6	6.7	6.7

This function is performed by Corporate Communications, First Nations and Métis Relations and Outsourcing Services. The increase in costs over the historical years through the bridge year is reflective of the activities in the First Nations and Métis Relations, Corporate Communications and Outsourcing Services programs. First Nations and Métis Relations programs sustain long-term relationship building and negotiations with First Nations and Métis communities and are impacted by the growth of Hydro One core SDO work programs. Corporate Communications programs are targeting improvements in customer communications regarding power outages while increasing customer education and engagement efforts and research to support improved customer communication. The current outsourcing contract with Inergi LP expires in 2015. The re-tendering process currently underway which results in additional costs for the Outsourcing Services group. More details on the re-tendering process are available in Exhibit C1, Tab 2, Schedule 7.

2.4.1 Corporate Communications

Corporate Relations is comprised of Corporate Affairs, External Relations and the Executive Office. Corporate Relations is responsible for ensuring that Hydro One Networks builds the strategic relationships required to advance corporate objectives and present a single, positive brand internally and externally. Corporate Affairs is responsible for corporate reputation, executive support, customer and employee communications, media relations, community investment, web communications and corporate brand identity. External Relations is accountable for supporting the company's relationships with the government and its key stakeholders. External Relations also leads the Public Affairs Group which supports Hydro One Networks' public consultation obligations and community relations programs. The Executive Office supports the executive team. It advances key strategic initiatives and interfacing with lines of business to assist in the implementation of these initiatives, coordinating the development of processes to ensure alignment within Hydro One Networks and a unified focus on key priorities.

In 2013, Corporate Relations costs increased primarily due to Corporate Affairs incurring one-time expenses, such as costs to support the Mobile Customer Discovery Centre and an increased number of customer surveys in support of this Custom Application. The Executive Office also absorbed the costs of two rotational staff in 2013. For the 2015-2019 forecast, these additional costs have not been included.

2.4.2 First Nations and Métis Relations

Another important role that falls within the Corporate Relations function is First Nations and Métis Relations. First Nations and Métis Relations programs foster and maintain long-term relationship building and conduct engagement with First Nations and Métis communities that may be impacted by Hydro One Networks core SDO work programs.

Hydro One Networks owns and maintains assets on reserve lands and within the traditional territories of First Nations & Métis Peoples. Hydro One Networks recognizes that First Nations and Métis peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. Building relationships with First Nations and Métis communities based upon trust, confidence, and accountability is vital to achieving our corporate objectives. The First Nations and Métis Relations group encompasses the following functions:

- Sustains long-term capability in the areas of First Nations and Métis relationship building, engagement and the successful development and implementation of initiatives to achieve Hydro One Networks' goals and objectives;
- Develops and maintains key relationships with government officials as well as representatives of key businesses including but not limited to other energy companies;
- Supports procurement opportunities for qualified First Nations & Métis businesses;
- Provides engagement services on projects and/or initiatives that potentially affect the First Nations & Métis peoples and communities;
- Provides leadership and advice within the company in the building of knowledge and awareness of First Nations and Métis historic and contemporary issues; and
- Develops, in conjunction with the Human Resources and Labour Relations departments, initiatives to enhance the level of aboriginal employment at Hydro One Network.

First Nations and Métis Relations costs are $3.1 million between 2015-2017 and $3.2 million between 2018-2019. The portion allocated to Hydro One Distribution is $1.2 million between 2015-2019.

The increase in costs in the 2014 bridge year and 2015-2019 test years is required to sustain long-term relationship building and engagement processes with First Nations and Métis as a result of the growth of the Hydro One Networks core SDO work programs.

2.4.3 <u>Outsourcing Services</u>

The mandate of the Outsourcing Services Group is to govern and manage the contractual relationship with the company's outsourcing partner (currently, Inergi LP) in a manner that fosters collaboration and optimizes value and minimizes risk by ensuring that contracted services are delivered. The Outsourcing Services Group is responsible for managing the design, development, and implementation of new service delivery agreements with Hydro One's suppliers.

In 2010, the Outsourcing Services Group extended the current outsourcing contract with the Inergi LP with the support of an external consultant. In 2011, the Outsourcing Services Group's costs are lower than its 2010 costs because these external consultant fees no longer applied.

The current outsourcing agreement with Inergi LP expires in 2015. Higher costs for the Outsourcing Services Group in the 2012 to 2014 period are primarily driven by: (a) fees for external support in preparing and issuing a request for proposals ("RFP") to replace the current outsourcing agreement, and (b) fees for a benchmarking study commissioned in 2013 to determine whether the costs under the current contract are market-comparable.

For the test years, the Outsourcing Services Group's annual costs are $2.9 million in 2015 and 2016, $3.0 million in 2017 and 2018, and $3.1 million in 2019. The portion allocated to Hydro One Distribution is $1.2 million in 2015, and $1.3 million annually for the period 2016 to 2019. The proposed spending for the test years is consistent with the actual spending in historical years.

2.5 General Counsel and Secretariat

Table 7 provides a summary of the costs of the General Counsel and Secretariat function:

Table 7
General Counsel and Secretariat Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	7.5	7.4	8.8	10.0	10.1	10.2	10.2	10.2	10.4	10.5	4.1	4.1	4.2	4.2	4.2

2.5.1 Overview

The offices of the General Counsel and Corporate Secretary ("GC&CS") provide legal advice and direction to Hydro One Networks and its affiliates, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&CS consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel.

The GC&CS functions in Hydro One Networks are set out below:

- Providing legal services to all business units including the company's major borrowing and financing initiatives, regulatory activities, transmission and distribution businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors-related activities, and arranging for the provision of legal services to the company. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions;
- Overseeing the Law and Corporate Secretariat functions; and
- Ensuring compliance with legal and regulatory requirements.

Hydro One Networks does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

The increase in costs for GC&CS is driven mainly by increased work requirements related to the GEA, securities law matters including registration in the United States with the Securities and Exchange Commission (SEC), corporate finance matters and pension-related matters. Examples of the additional workload include procurement-related work due to large work programs, preparation of legal agreements associated with distributed generation, real estate-related legal work to obtain land and land rights for new development projects, and preparation of renewed securities-related documents for filing in Ontario and with the SEC.

2.5.2 Law

Law provides legal advice to all business units of the company, acting as an internal law firm. It advises on most aspects of law affecting Hydro One Networks, and relies on its experience and knowledge of the company's business in providing economic and timely advice. This function maintains core knowledge of the law and the company's business.

2.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board of Directors and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations.

2.6 Regulatory Affairs

Table 8 provides a summary of Regulatory Affairs costs:

Table 8
Regulatory Affairs Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Regulatory Affairs	10.0	9.1	7.4	7.8	8.3	8.0	7.9	7.5	7.8	7.9	4.0	4.0	3.9	4.0	4.1
OEB/NEB Costs	11.3	11.0	13.2	14.2	15.8	13.5	14.5	14.0	15.6	15.0	7.9	8.4	8.3	9.2	8.9
Total Cost	**21.3**	**20.1**	**20.6**	**22.0**	**24.1**	**21.5**	**22.4**	**21.6**	**23.3**	**22.9**	**12.0**	**12.4**	**12.1**	**13.2**	**12.9**

2.6.1 Overview

Regulatory Affairs consists of the Compliance, Applications and Regulatory Administration functions. The costs include Hydro One Networks' share of the Ontario Energy Board ("OEB") costs, including the OEB quarterly assessment costs, OEB proceeding-specific costs and OEB-ordered intervener cost awards.

2.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO, the OPA, and the National Energy Board. Through this function, it is responsible for developing strategy and coordinating the company's submissions to these bodies as well participation in regulatory initiatives.

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including distribution and transmission rates, transmission leaves–to-construct, merger/ acquisition/ amalgamation/ divestiture applications and area and system supply planning. In addition to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing reporting and other activities. The function prepares quarterly and annual reports required under OEB Reporting and Record-keeping Requirements. Work includes meeting, reporting on, and responding to regulatory compliance issues. Pricing and cost allocation analysis and support are also provided within Regulatory Affairs for rate applications. This includes the development of rate structures and rates for the regulated transmission and distribution tariffs applicable to Hydro One Networks and provides support in submitting and defending rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

Load Forecasting and Load Data Management Units are included within the Regulatory Affairs group. Load forecasts are developed to enable system planning and financial planning which underlie Hydro One Networks ' financial forecasts. The load forecast function provides load forecast data including the capture of conservation and demand management impacts. Load forecast staff support the company’s business units and the OPA with forecasting analysis and evaluation covering time of use, bypass and embedded generation. The Load Data Management Unit provides analytical support for conservation and demand management projects and provides load research analysis.

Regulatory costs in 2014 through 2019 are being driven by an extremely aggressive regulatory program. This includes a distribution rate application for 2015-2019 and transmission rate applications for 2015-2016, 2017-2018 and 2019-2020. Furthermore, the OEB is continuing a busy and challenging program of reviews and initiatives, most of which involve the company. At the present time, the OEB is conducting several generic proceedings on issues such as:

- Code amendments to the Transmission and Distribution System Codes;
- Consultation to Review the Framework Governing the Participation of Intervenors in Board Proceedings;
- Initiative to Develop Electricity Distribution System Reliability Standards;
- Regional Planning for Electricity Infrastructure; and
- Numerous other matters that arise from time to time.

2.6.3 Ontario Energy Board Costs

Under the *Ontario Energy Board Act, 1988*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO, the OPA, Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of six categories – electricity distribution, electricity transmission, gas distribution, IESO, OPA and Ontario Power Generation. Hydro One Networks' allocation arises from OEB costs related to electricity distribution and transmission.

2.7 Security Management

Table 9 provides a summary of Security Management program costs.

Table 9
Security Management ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	2.4	3.0	3.1	3.7	4.8	4.8	4.6	4.6	4.7	4.8	2.5	2.4	2.4	2.4	2.5

The Security Management function (formerly referred to as Corporate Security Services) exists to enable Hydro One Networks' success primarily in the protection of assets (assets include people, property and information), development and maintenance of Business Continuity and Emergency Preparedness & Response Plans and to assist in the reliable delivery of electricity. Security Management adds value by providing advice, coordination, guidance, investigative, technical and intelligence gathering expertise and services to company staff that support and optimize the reliable delivery of electricity, the protection of Hydro One Networks' assets, and the resumption of business in the event of an all hazards (natural, technological or human-caused) incident. Effective asset protection and recovery can be the primary differentiating factor between success and failure for a critical infrastructure organization such as Hydro One Networks. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity and safety.

The increase in costs is a result of an increased focus on a variety of mitigating strategies to reduce the impact of metal theft (primarily copper) that threaten the reliability of the transmission and distribution systems and the safety and security of staff, first responders and the general public.

Incidents of copper theft have dropped, in part, due to adding security protection systems at heavily targeted transmission sites. However, more organized criminal incidents have occurred in relation to metal thefts recently, primarily targeting stations that have not benefited from increased capital expenditures for protection systems. Although the total number of incidents has dropped, the average loss per incident is increasing due to the sophistication and organization of these crime groups. These crimes take longer to investigate, and prevention methods and strategies are often very complex and costly.

Total Security Management costs are $4.8 million in 2015, $4.6 million in 2016 and 2017, $4.7 million in 2018 and $4.8 million in 2019. The amount allocated to Hydro One Distribution is $2.5 million for 2015, $2.4 million from 2016 to 2018 annually, and $2.5 million in 2019.

2.8 Internal Audit

Table 10 provides a summary of Internal Audit costs.

Table 10

Internal Audit Function ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Total Cost	2.8	3.1	3.5	3.7	3.6	3.6	3.6	3.6	3.7	3.8	1.1	1.1	1.1	1.2	1.2

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It provides independent and objective assurance and consulting services designed to add value to and improve Hydro One Networks' operations. The mandate for Internal Audit is to provide independent assurance to the CEO and the Board of Directors that internal controls are adequate in areas of high-risk and to follow-up and report on management actions to address findings from past audits.

The department helps the company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes. The total costs for this function are $3.6 million annually from 2015 to 2017, $3.7 million in 2018, and $3.8 million in 2019. The portion allocated to Hydro One Distribution is $1.1 million annually from 2015 to 2017 and $1.2 million annually from 2018 to 2019.

2.9 Real Estate and Facilities

Table 11 provides a summary of Real Estate and Facilities costs.

Table 11

Real Estate and Facilities ($ Millions)

Description	Historic				Bridge	Test					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Real Estate	8.6	9.3	8.8	8.7	9.7	9.8	9.8	9.9	10.0	10.2	1.9	1.9	1.9	1.9	1.9
Facilities	41.3	42.3	45.8	48.1	50.5	51.6	51.5	52.5	53.8	56.0	22.9	22.8	23.3	23.9	24.9
Total Cost	49.9	51.6	54.6	56.8	60.2	61.4	61.3	62.4	63.8	66.2	24.8	24.7	25.2	25.8	26.8

2.9.1 Overview

The total cost for the Facilities and Real Estate function in 2015 is $61.4 million, with $24.8 million allocated to Hydro One Distribution. The 2016 cost is $61.3 million, with $24.7 million of that allocated to Hydro One Distribution. The 2017 cost is $62.4 million, with $25.2 million of that allocated to Hydro One Distribution. The 2018 cost is

$63.8 million, with $25.8 million of that allocated to Hydro One Distribution. The 2019 cost is $66.2 million, with $26.8 million of that allocated to Hydro One Distribution.

The 2015-2019 funding is required for the expanded facilities work program that responds to current and future anticipated Hydro One Networks' work space accommodation needs. This includes new facilities in the field. The facilities work program accounts for approximately 84% of total funding in test years 2015 to 2019.

The increase in funding requirements is mainly driven by new facilities and building additions being put in-service. New facilities will be replacing existing facilities at the end of their useful lives, and new facilities are also needed to meet increased accommodation needs driven by Hydro One Networks' work program and operating requirements (which include housing specialized work equipment). The increase in funding requirements in bridge year 2014 and test years 2015 to 2019 is attributable to planned office improvements, which are expected to result in additional swing space and office moves costs. The funding requirements in the bridge and test years also reflect corporate health and safety initiatives and expected increases in fixed operating costs.

2.9.2 Real Estate Services ("RES")

Real Estate Services manages Hydro One Networks' land rights portfolio across the Province. This involves maintaining rights across over 200,000 acres of owned corridor, easement and "statutory right" properties and acquiring any new rights needed to ensure the safe and reliable operation of the transmission and distribution system. In addition, Real Estate Services oversees the management of Hydro One Networks' rights associated with distribution and transmission lands, stations and other property.

Real Estate Services' key work activities include:

- managing the acquisition of new real estate rights, which supports the company's distribution and transmission development and reinforcement project initiatives across the Province including those designed to accommodate renewable power sources on the grid;
- managing the Provincial secondary land use program on behalf of Ministry of Infrastructure/ Infrastructure Ontario leasing transmission corridor lands to external parties);
- managing easement, other rights agreements on public/private sector, railway and other lands;
- managing First Nations land use permit settlements on reserve lands;
- managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services; and
- maintaining Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as appropriate.

2.9.3 Facilities

The Facilities work program includes all aspects of company work space requirements which comprise not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities. The Facilities function manages all of the building and site facilities across the company. This includes leasing costs and contract management for head office. In addition, it includes costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre). The Facilities organization is responsible to ensure program delivery in terms of service levels, planned capital improvements and providing for Hydro One Networks' accommodation needs.

The Facilities program focuses on providing employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre).

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards. This program includes:

- providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements;
- managing 46 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes;

- co-ordinating activities related to the ongoing management, operation, maintenance and inspection of 91 Administrative/Service Centres and Ontario Grid Control Centre; and
- providing support services for head office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.

The facilities costs are largely driven by space needs (including workspace and housing space for material and work equipment) which is affected by company work programs and factors such as changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs. Accommodation needs are influenced by the development and growth of the company's work programs and initiatives.

The majority of the Facilities work program costs are fixed. The Facilities work program is driven by fixed-cost contractual obligations, which arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements. Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. 2015-2019 test year funding also takes into consideration changing factors in the operating environment.

3.0 OTHER OM&A

Other OM&A expenses are comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 12.

Table 12
Total Distribution Other OM&A ($ Millions)

Description	Test				
	2015	**2016**	**2017**	**2018**	**2019**
Capitalized Overhead	(85.9)	(81.4)	(80.2)	(82.5)	(85.3)
Environmental Provision	(14.2)	(22.0)	(22.4)	(22.0)	(21.6)
Indirect Depreciation	(13.2)	(13.7)	(14.0)	(14.4)	(14.8)
Other	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)
Total	**(116.8)**	**(120.6)**	**(120.1)**	**(122.4)**	**(125.2)**

3.1 Capitalized Overhead Credit

Table 13
Distribution Corporate Overhead Credit ($ Millions)

Description	Test				
	2015	**2016**	**2017**	**2018**	**2019**
Distribution	(85.9)	(81.4)	(80.2)	(82.5)	(85.3)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that support capital work. These costs are included in shared services and in the lines of businesses. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch.

3.2 Environmental Provision

Table 14
Distribution Environmental Provision ($ Millions)

Description	Test				
	2015	2016	2017	2018	2019
Distribution	(14.2)	(22.0)	(22.4)	(22.0)	(21.6)

In 2001, Hydro One Networks first recognized a liability on its balance sheet for the present value of the future estimated environmental expenditures needed manage the risks associated with two legacy environmental issues inherited from Ontario Hydro. These risks pertained to polychlorinated biphenyls (PCBs) and two chemically contaminated lands. Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the sustaining OM&A work program. The amount is then removed from OM&A as the costs are charged to the balance sheet provision. As well, the offsetting environmental regulatory asset is amortized based on the pattern of expenditure. The resultant impact on revenue requirement of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and Amortization' on the operating statement.

3.3 Indirect Depreciation

Table 15
Distribution Indirect Depreciation ($ Millions)

Description	Test				
	2015	2016	2017	2018	2019
Indirect Depreciation	(13.2)	(13.7)	(14.0)	(14.4)	(14.8)

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes, it is necessary to remove this depreciation amount from OM&A work programs and appropriately charge it as a depreciation expense. The credit increases in the test years due to the expanded use of T&WE in the larger SDO work program.

3.4 Other

Table 16
Distribution Other Costs ($ Millions)

Description	Test				
	2015	2016	2017	2018	2019
Other Costs	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)

These costs represent material unexpected or non-recurring expenses. For example, they include items such as adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

COMMON CORPORATE COSTS OM&A – ASSET MANAGEMENT

1.0 OVERVIEW

The Transmission and Distribution businesses are operated using the Asset Management model, which the company adopted in 1998. The model separates the asset management functions of planning, decision-making and approvals from the services functions of engineering, construction and customer and grid operations which execute approved plans. The Asset Management model is further discussed in Exhibit A, Tab 6, Schedule 1.

The Asset Management organization remains focused on ensuring that the necessary transmission and distribution assets are planned, acquired, constructed, maintained and operated such that they deliver the required function and level of performance expected by customers in a sustainable manner over the long term. Asset Management is responsible for delivering on the following key accountabilities:

- Developing system investment plans for the sustainment, development and operation of the Distribution and Transmission systems consistent with good asset stewardship practices;
- Developing asset strategies, long-term perspectives and investment plans to support corporate objectives;
- Optimizing the release, bundling and sequencing of the work to ensure the effective delivery of the investments within the plan;
- Redirecting investments in response to new or unforeseen factors (e.g. major storms) and drivers.

Asset Management costs for the historical, bridge and test years are shown in Table 1. The costs allocated to the Distribution business are also provided in Table 1.

Table 1
Asset Management Function ($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
System Investment	43.7	45.0	42.5	38.4	41.6	41.5	39.4	38.7	37.8	38.2	14.5	13.8	13.5	13.4	13.5
Asset Stewardship and Strategies	15.3	14.6	15.1	13.9	14.3	14.0	14.1	14.0	14.4	14.8	3.9	4.0	4.0	4.2	4.3
Total	**58.9**	**59.6**	**57.5**	**52.3**	**55.9**	**55.5**	**53.5**	**52.7**	**52.2**	**53.1**	**18.4**	**17.8**	**17.6**	**17.5**	**17.8**

Total Asset Management costs decrease from 2015 to 2019 and the costs allocated to the Distribution business also decline from $18.4 million in 2015 to $17.8 million in 2019. The work undertaken within Asset Management is not expected to decline, however there are productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for the organization. This strategy seeks opportunities to distribute the workloads of retiring staff among existing staff to mitigate the extent to which it is necessary to backfill for retirements and engage external resources. This strategy will also leverage the use of various tools to help fewer planners make the investment decisions. The reduction in budgeted OM&A costs reflects the company's commitment to deliver value to rate payers.

The primary focus of Asset Management is on core work programs, with overarching initiatives that adapt the business to changing industry and regulatory standards, government policy, and an aging workforce and asset base. These initiatives have notable resource demands, and must therefore be strategically rolled-out to balance cost-effective and reliable electricity supply with efforts to improve, modernize, and address aging infrastructure. The overall resource strategy has therefore needed to target flexibility and adaptability so that costs, core work program impacts, and long term workforce capacity can be appropriately managed.

Major Overarching Cost Drivers:

Aging Assets and Increasing Complexity*:* Asset Management resources must manage the increasing complexities that result as large portions of Hydro One's asset fleet reach the end of their expected service lives and the transmission and distribution systems are further adapted to integrate distributed generation and smart grid into the distribution system. These complexities particularly impact the System Investment activities of replacement planning and decision making, evaluating modern technological developments, adapting to regulatory change, and strategies for enhancing performance.

In addition, System Investment has recently implemented enhancements in Hydro One's asset analytics and integrated planning capability to meet the increased demands of an aging asset base.

Aging Workforce: The bow-wave of end-of-expected service life asset replacements that is expected in the next ten years, the increasingly stringent reliability compliance standards, and the opportunities for technological modernization of the power system have resulted in a need to augment staff resources and expertise in the System Investment area. However, this is complicated by the significant loss of experience that will result from the large portion of the workforce that is approaching retirement. The need for structured information transfer is particularly acute because our demographic composition involves marked segmentation between staff that have more than 20 years of experience, and staff with less than 5 years of experience. This experience gap drives the need for a period of overlap between the staff approaching retirement and staff that are intended to take over their workloads once they retire. Protection and Control staff for instance, require 7-12 years of development after graduation and therefore some hiring must occur in advance of the expected retirement dates to allow time for experience-building and knowledge transfer from current employees.

FIT and Micro-FIT: The decline in System Investment costs through the test years reflect the impact and maturing of the OPA's FIT and Micro-FIT programs. The timelines and technical complexities of these programs initially necessitated non-permanent resources to support these programs and evaluate the project impacts on the distribution grid.

Asset Management Re-alignment (2012 to 2013)

In the current application, some of the functions in Asset Management have been re-aligned compared to the previous Transmission Cost of Service application (EB-2012-0031). This re-alignment has resulted in a consolidation of some activities previously included in the Business Performance category with the System Investment and Asset Stewardship and Strategies functions. Other Business Performance activities have left the Asset Management to better align with the work function; these changes have financial impacts on Asset Management OM&A in this application and the impacts are outlined in Table 2 below:

Table 2

Impact on Asset Management OM&A due to Asset Management Re-alignment

	2010	**2011**	**2012**	**2013**	**2014**
Asset Management OM&A Filed in EB-2012-0031	**58.9**	**59.6**	**64.2**	**62.5**	**62.7**
Minus:					
Performance Management (1)				(3.1)	(3.2)
Advanced Distribution System Alignment (2)				(0.3)	(0.3)
Asset Management Cost Reductions (3)			(6.6)	(6.8)	(3.3)
Asset Management OMA in this Application	**58.9**	**59.6**	**57.5**	**52.3**	**55.9**

(1) Performance Management costs for the bridge and test years, previously included in the Business Performance category have moved out of Asset Management and are now included in Shared Services- Common Corporate Functions and Services & Other OM&A; see Exhibit C1, Tab 2, Schedule 8.

(2) Advanced Distribution System Alignment costs for the historic, bridge and test years, previously included in the Business Performance category, have moved out of Asset Management and are now included in Customer Service; see Exhibit C1, Tab 2, Schedule 5.

(3) The cost reductions in Asset Management of $6.8 million in 2013 and $3.3 million in 2014 represent shifts in the timing of hires to later years in accordance with the demands of the sustainment, development, and operations work programs and savings enabled by business process improvements.

2.0 System Investment

The following Table 3 provides a summary of System Investment costs:

Table 3
System Investment Function ($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
System Investment	43.7	45.0	42.5	38.4	41.6	41.5	39.4	38.7	37.8	38.2	14.5	13.8	13.5	13.4	13.5

Note: Organization reflects a partial consolidation of activities from the System Investment and former Business Performance function.

2.1 Overview

System Investment develops and scopes transmission and distribution plans to address equipment performance, system reliability, system capacity, system capabilities, compliance obligations, customer requests, as well as OPA and Government initiatives. This function also leads Asset Management's participation in the various regulatory processes including Transmission and Distribution rate applications and Section 92 Leave to Construct applications. System Investment ensures integration of all aspects of Asset Management including investment planning, execution planning, work bundling and release of the capital and OM&A work programs in accordance with the Asset Management model and the Asset Management Planning Process, which is discussed at Exhibit A, Tab 17, Schedule 2.

The year over year cost trend from 2014 to 2019 reflects a consistent decrease in System Investment costs. The work undertaken within System Investment is not expected to decline, however there are productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for the organization. Given the current staff demographics, initiatives are underway to facilitate the structured transfer of information from highly experienced employees nearing retirement age to newer employees to help mitigate the experience gap that is expected to result as large portions of the workforce retire. Further, this strategy seeks opportunities to distribute the workloads of retiring staff among existing staff to mitigate the extent to which it is necessary to backfill for retirements and engage external resources.

The resource demands for these functions have intensified in relation to the complexities brought about by an aging asset base, the increasing levels of transmission and distribution sustainment work relating to the refurbishment and replacement of assets to maintain condition and reliability, and more stringent regulatory compliance requirements, industry standards and codes. Given that workloads are not declining, this strategy is contingent on productivity realization, and reflects Hydro One’s commitment to deliver value to rate payers.

The decrease in System Investment spending from 2010 to 2012 must be considered in combination with the increase in Asset Strategy costs, as this reflects a realignment of work between these two functions. Further decreases from 2010 to 2012 reflect the maturing of the OPA’s FIT and Micro-FIT program impacting the need for non-permanent resources; the short term increased resource demands were driven by efforts to accommodate distributed generation:

- Additional preparation of engineering protection and control specifications required to accommodate generators on a distribution system that was primarily designed for load customers;
- Additional studies to determine the impacts of reverse flow on power equipment, as new local generation may exceed the load on a feeder which will result in power

flows in the opposite direction to that designed;

- Development of P&C standards for transmission and distribution stations, and other controllable elements;
- An increase in the number of requests for generation applications, requiring connection impact assessments;
- The need to develop new standards related to configurations or connections to the Transmission and Distribution networks;
- The need to develop, scope and obtain approvals for distribution plans in response to Government policy decisions related to the province's generation mix, in consultation with the OPA;

2.2 System Investment Activities

System Investment activities include:

- Developing Transmission and Distribution sustainment, development and operations investment plans consistent with Hydro One's objectives, constraints, strategies, and asset stewardship obligations, and obtaining approvals for such plans;
- Interfacing and collaborating with external governmental, regulatory and planning authorities on matters of planning direction, requirements, policy and guidance, and integrating such into the investment plans;
- Identifying, scoping and obtaining approval for specific investments in support of approved investment plans;
- Engaging with service delivery units to ensure the effective execution of specific investments;
- Analyzing the results of project and program execution and integrating these into future plans;
- Supporting the redirecting and re-prioritizing of investments in response to unforeseen events and work execution opportunities;

- Supporting the development of opportunities to optimize leveraging of Hydro One Networks' assets (e.g. distributed generation connections, secondary land use, and utility boundary adjustments);
- Performing technical studies to assess the viability of proposed connections, alternatives or investment plans;
- Investigating and addressing power system disturbances;
- Conducting various asset and system centered analytics including asset condition assessments in the context of the Reliability Centric Maintenance methodology and integrating the results into specific investment plans;
- Monitoring equipment and network performance and addressing issues as these are identified;
- Establishing performance standards that form the basis for detailed engineering designs;
- Responding to customer requests for new or expanded connections or customer concerns regarding connection security or power quality;
- Advising external agencies and customers of the Transmission and Distribution impacts of their plans;
- Consulting with affected stakeholders regarding new Transmission and Distribution facilities;
- Development and leadership of strategies and plans that support corporate goals related to the Transmission and Distribution businesses;
- Evolving and enhancing the implementation of the asset management model;

- Advancing and leading the OM&A and capital Investment Planning process in the development of multi-year Transmission and Distribution Investment Plans;
- Analyzing and managing project and program costs and results and collaborating with service delivery units to ensure targets are achieved;
- Managing the execution planning, work bundling and releasing processes, and redirecting investments in response to unforeseen events and work execution opportunities;
- Managing the business case approval and interim review of variance processes;
- Developing work collaboration tools, systems and processes to drive continuous improvements across the corporation;
- Ensure an integrated approach to data, systems, and processes as well as contributing to change management within Hydro One.
- Developing and advancing better approaches and tools in such areas as asset analytics, leading to improved asset sustainment planning approaches;
- Providing regulatory support for Asset Management and others in Hydro One including evidence development for regulatory filings, expert witness support, and interrogatory response and undertaking preparation, and through preparing documentation and supporting the Section 92 Leave to Construct process for major transmission projects; and
- Specifying technical requirements and work in such areas as new technologies (e.g. smart meters, IEC 61850), animal abatement, transformer refurbishment (core heating) and remote monitoring.

3.0 ASSET STEWARDSHIP AND STRATEGIES

Table 5 provides a summary of Asset Stewardship and Strategies costs:

Table 5
Asset Stewardship and Strategies Function ($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Asset Stewardship and Strategies	15.3	14.6	15.1	13.9	14.3	14.0	14.1	14.0	14.4	14.8	3.9	4.0	4.0	4.2	4.3

Note: Organization reflects a partial consolidation of activities from the Asset Strategy and former Business Performance functions

3.1 Overview

The Asset Stewardship and Strategies group provides leadership and supports asset stewardship by developing and advancing functional, business and technological strategies and plans, as well as detailed policies and standards. This group also includes research and development activities, and liaison with external industry organizations, government agencies and universities. Also included is funding for property, boiler and machinery insurance costs. The insurance amounts for the test years are provided in Table 6 below:

Table 6

Property, Boiler and Machinery Insurance

	Historical			Bridge	Test Years				
	2011	2012	2013	2014	2015	2016	2017	2018	2019
Property, Boiler and Machinery Insurance	5.0	5.5	6.0	6.6	6.9	7.2	7.5	7.8	8.1

The steady year-over-year trend indicates that assumed cost escalations are being offset by decreases in other base costs. As in the case of System Investment, the work undertaken within the Asset Stewardship and Strategies group is not expected to decline. Rather, there are productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for Asset Stewardship and Strategies. This resource strategy seeks opportunities to distribute the workloads of retiring staff among existing staff to mitigate the extent to which it is necessary to backfill for retirements and engage external resources. Given that workloads are not declining, this strategy is contingent on productivity realization, and reflects Hydro One's commitment to deliver value to rate payers.

The overall trend in Asset Stewardship and Strategies spending must be considered in combination with the decrease in System Investment costs, as this reflects realignment of work between these two functions. In particular, the Asset Stewardship and Strategies group consolidated and intensified its focus in the areas operating reliability compliance requirements and the management of corporate operational policies.

3.2 Asset Stewardship and Strategies

Asset Stewardship and Strategies activities include:

- Developing and advancing technological, functional and business strategies for Asset Management and Hydro One;
- Developing and advancing asset and business related policies, practices and standards for Asset Management and Hydro One; Supporting the planning and advancement of the Advanced Distribution System (ADS) initiative, including Hydro One's "Living Lab" in the Owen Sound and Walkerton areas as well as subsequent phases;
- Interfacing and collaborating with governmental agencies such as the OPA, ORF (Ontario Research Fund) and OCE (Ontario Centres of Excellence) on asset management matters, and research and development issues affecting the electricity industry;
- Providing expert participation in, and representing Hydro One's interests on, various national and international industry entities and standard-setting bodies including CIGRE, CEA, CEATI, IEEE, NERC, NPCC, the North American Transmission Forum, NIST, and the IESO. For example, this function participates in reliability standards development and compliance monitoring with NERC and the NPCC, and also represents Canada at the International Electrotechnical Commission (IEC). In addition, this function serves as the transmitter representative on the Independent Electricity System Operator ("IESO") Technical Panel, which reviews and

recommends amendments to the Ontario wholesale electricity market rules, and advises the IESO Board of Directors on specific technical issues related to the operation of the Ontario Electricity Market;

- Providing oversight, overall management and subject matter expertise for interpreting, advising upon and demonstrating Hydro One's compliance with North American or regional reliability standards (IESO/NERC/NPCC) to external regulatory authorities (e.g. IESO's MACD) pursuant to Hydro One's license and market rules' obligations;
- Managing or contributing to research and development in such areas as smart grid, electrical vehicles, energy storage and distributed generation, through industry and research organizations (e.g. EPRI and CEATI) and Ontario universities;
- Interfacing and collaborating with Ontario universities on matters of electrical or power-systems engineering;
- Leading Asset Management's business improvement and employee engagement plans and initiatives; and
- Overseeing the governance of corporate standards and ensure appropriate standards are in place ahead of corporate requirements.
- Advancing and integrating all Asset Management functions, initiatives, plans, processes and practices in support of overall asset stewardship;
- Participating in the development of, and demonstrating compliance with North American or regional reliability standards (e.g. Market Assessment and Compliance Division (MACD) audits);and
- Managing the Operating Compliance Management function including the Compliance Management System (CMS) and supporting the demonstration of compliance with North American or regional reliability standards (IESO/NERC/NPCC) to external regulatory authorities (e.g. IESO's Market Assessment and Compliance Division (MACD)).

COMMON CORPORATE COSTS OM&A - INFORMATION TECHNOLOGY

1.0 OVERVIEW

Information Technology ("IT") refers to computer systems (hardware, software and applications), data and voice communication systems that support business processes and allow employees to perform their work.

IT work programs include both OM&A and capital items and involve: the ongoing maintenance and sustainment of existing and newly commissioned applications and technologies; the development and implementation of new technologies or systems; the provision of Business Telecom services; and the overall management and control of the information technology program – including capital projects. IT capital investments are made in accordance with approved business strategies and are described in Exhibit D1, Tab 3, Schedule 7.

OM&A costs associated with supporting Hydro One's information technology assets are shown in Table 1 and are described below.

Table 1

Information Technology Summary of OM&A Expenditures

($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Sustainment	84.6	81.7	88.5	84.4	84.5	88.7	87.7	85.8	88.3	90.2	54.4	53.8	52.6	54.2	55.3
Development[1]	11.9	11.0	8.2	21.2	21.0	19.7	21.6	23.7	21.9	21.7	12.4	13.8	14.9	13.8	13.7
Business Telecom	16.9	18.5	18.4	19.4	18.5	18.0	18.4	18.4	18.4	18.6	8.1	8.3	8.3	8.3	8.3
IT Management & Project Control	20.1	19.5	19.0	21.5	24.2	24.2	23.6	23.0	23.0	22.7	10.8	10.6	10.3	10.3	10.2
Cornerstone	1.8	1.4	8.6	18.7	4.5										
Total	**135.3**	**132.1**	**142.7**	**165.2**	**152.7**	**150.6**	**151.3**	**150.9**	**151.6**	**153.2**	85.7	86.5	86.1	86.6	87.5

[1] Customer Care work related to Regulatory Compliance and Service Enhancements moved to IT from Customer Service Operations in 2013

1.1 Sustainment

Sustainment costs are costs to support the Hydro One information technology applications and infrastructure. Some of these costs are paid to Inergi LLP ("Inergi") pursuant to the current outsourcing contract which expires in 2015 for which a re-tendering process is underway. The remaining costs are for third party software/hardware license and maintenance fees.

1.2 Development

The development budget is comprised of application upgrades, enhancements and the OM&A portions of capital projects. The funds are required to maintain the applications at vendor-supported levels and to support enhancements to those applications.

1.3 Business Telecom

Business Telecom costs include data and voice telecommunications and associated maintenance of Hydro One's telecom network. Changes in costs vary with the addition of data and voice telecom capacity at sites throughout the province, and the addition of security-related services for the expanding telecom network.

1.4 IT Management and Project Control

IT Management and Project Control costs relate to IT administration, outsourced services oversight, project governance and reporting, system and security architecture, program and spend coordination, and Quality Assurance ("QA")/Quality Control ("QC") processes.

Technology costs are validated through Hydro One's IT governance process. IT governance looks proactively at IT strategy, project expenditures and service delivery to align technology spend with business and corporate objectives. The IT governance model involves the senior business managers who provide guidance, direction and support to the decision-making for corporate technology decisions.

2.0 IT SUSTAINMENT OM&A

Table 2 shows the specific expenditures for IT sustainment of the Information Technology platform.

Table 2

OM&A Sustainment of Information Technology

($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Base IT Sustainment Services	70.9	68.8	73.6	68.2	65.5	66.7	64.9	63.4	65.0	66.9	40.9	39.8	38.9	39.9	41.0
3rd Party Contracts	13.7	12.9	14.9	16.2	19.0	22.0	22.8	22.4	23.3	23.3	13.5	14.0	13.7	14.3	14.3
Total	**84.6**	**81.7**	**88.5**	**84.4**	**84.5**	**88.7**	**87.7**	**85.8**	**88.3**	**90.2**	54.4	53.8	52.6	54.2	55.3

IT Sustainment work includes: help desk and desk-side support; implementing system and security patches; applying fixes for applications, resolving application problems; decommissioning or installing software applications or equipment; maintaining and operating Hydro One's IT assets located at offices throughout the province and within the data centres; data storage capacity and data storage management; and disaster recovery.

3rd Party Contract costs include amounts which are paid to third parties for software and hardware licenses and annual maintenance fees.

2.1 Base IT Sustainment Services

The term "Base" IT Sustainment Services refers to those IT services outsourced to Inergi and which are scheduled in the negotiated contract. The new outsourcing contract will continue to refer to those same IT services.

Base IT services are discussed under the four categories below.

Application Maintenance

Application maintenance includes the work to maintain, address and fix matters associated with approximately 875 business software applications (this includes core business applications, desktop tools and specialty software) used by the various business units across the Province. Within these applications there are business critical software used in major functional areas, such as those shown in Table 3, which support business processes across the enterprise.

Based on support levels established by IT and the respective business operations, applications are managed via the ITIL (IT Infrastructure Library) - framework focusing on Incident, Problem, and Change Management. Application incidents and user inquiries are logged, prioritized, and managed through to resolution.

Table 3
Strategic Information Technology Systems

IT Systems	Description
Desktop Applications	These include Microsoft Office XP and the Windows 7 and Office 2010 platforms (for example, Word, Excel, Access, and PowerPoint), e-mail, Internet browser, and various other applications such as anti-virus and directory functions.
SAP™	This is an integrated Enterprise Resource Planning, Business Intelligence, and Enterprise Asset Management application suite that provides Asset and Work Management, Purchasing and Supply Chain as well as Inventory Management functions. It also provides General Ledger, Accounts Receivable, Fixed Assets, Project Accounting, Payroll, Time Reporting, Reporting, Human Resources and Pension functions. Customer Information System (CIS) provides improved call center interactions with our customers, increased accuracy and timelines in our billing process, and improved ability to help our customers address their problems with up to date information.
Contact Centre Technology	This suite of applications enables contact centre operators to respond to customers (service requests, billing inquiries, information), including telephony interfaces and call centre technology and provides operators scheduling and service quality-monitoring functions.
Field Design Tool (ArcFM)	This is a geographic application that is used to design and modify customer connections to the electrical distribution system as part of the GIS suite of applications.

IT Systems	Description
Work Execution Tools	Work Execution Tools consists of a collection of applications which are used to plan, schedule, dispatch and report on field work completion. The applications are linked to ArcFM and SAP through the use of enterprise middleware.
Smart Meter Head End System and MDMR Interface	The billing system produces bills for customers through its integration with the IESO meter data management repository (MDMR) and the Smart Meter Infrastructure.
Computer Aided Design and Drafting (CADD)	Computer Aided Design and Drafting is a suite of tools that aid in the design, engineering and construction of Transmission, Distribution, and Network infrastructure.

Data Centre Services

Data centre services include the operations, maintenance, and management of hardware (servers, mainframe, storage area network and data storage devices), operating systems, associated applications and infrastructure located at the data centre facilities. This hardware is used to run enterprise business applications, noted above, that are critical to operating the business.

Data Centre service levels have been established to ensure the reliable operation of business applications and are based on system criticality. The system hardware is located at production and backup data centres, which have the required system redundancies including 24/7 monitoring. Hydro One utilizes the backup data centre facility as a disaster recovery site in the case it is unable to operate from its production data centre.

Distributed Server Sustainment

Distributed server sustainment includes the support services that maintain and operate the application and file servers that are located at various Hydro One facilities across the province. The servers are used to run business applications and administration systems such as file sharing, e-mail exchange, web hosting and security monitoring systems. This work is required to maintain the reliability of the business applications supporting business operations.

Help Desk and Deskside Support

Help Desk and Deskside Support includes daily management and maintenance services delivered to employees across the Province.

The support function is provided through two key service areas: the Help Desk which provides centralized incident resolution by phone and through e-mail for all IT and telecom service areas; and Deskside Support which provides physical desk side support to fix hardware and software problems for laptops, desktops and rugged tablet computers. Deskside Support includes the support for IT peripherals such as printers, plotters, scanners and other equipment.

Deskside and Help Desk support is available to all users across the province and assistance can be provided by telephone, remotely through the data network, or if necessary through the use of Inergi field technicians. Effective and timely response ensures the efficient operation of the technology infrastructure which enables Hydro One staff to perform their work unimpeded.

Base IT Sustainment Costs Summary

In 2013 and 2014, costs decline year over year due to the scheduled price reduction in the Inergi Outsourcing contract and the IT Sustainment savings realized for the CIS replacement project. In 2015, there is a small but expected increase in cost as this is a transition year in terms of the outsourcing contract. In 2016 and 2017, the new contract savings will be realized thus reducing the costs. In 2018 and 2019, the normal growth in work program will begin to offset the contractual savings.

2.2 3rd Party Contracts

3rd Party Contracts are the fees related to hardware maintenance, application software license and maintenance fees that are paid to third party vendors for the IT applications and infrastructure used by Hydro One.

License or maintenance agreements are usually subject to annual increases as part of the contractual terms with the vendor. These fees are subject to annual audits by the third party vendors to confirm the fees match the services provided.

In 2014 and 2015, contract costs increase due to an expected 15% increase in software license fees and higher volumes when the Microsoft Enterprise contract is renewed in November, 2014. Costs stabilize in 2016 through 2019.

3.0 IT DEVELOPMENT OM&A

Table 4 lists the expenditures driven by non-Capital IT projects and the OM&A portions of capital projects.

Table 4

OM&A Development Expenditures

($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
Enhancements[1]	8.6	9.5	4.3	16.9	9.8	9.7	10.6	11.8	11.4	11.4	6.6	7.3	7.9	7.5	7.5
Upgrades	3.2	1.5	3.9	3.9	7.6	7.6	8.9	9.3	8.6	8.6	4.7	5.5	5.8	5.4	5.4
Impact of Capital Projects	0.1	0.0	0.0	0.4	3.6	2.4	2.1	2.6	1.9	1.7	1.1	1.0	1.2	0.9	0.8
Total	**11.9**	**11.0**	**8.2**	**21.2**	**21.0**	**19.7**	**21.6**	**23.7**	**21.9**	**21.7**	12.4	13.8	14.9	13.8	13.7

[1] Customer Care work related to Regulatory Compliance and Service Enhancements moved to IT from Customer Service Operations starting in 2013

3.1 Enhancements

Enhancements include required application, data and process changes to SAP and Non-SAP systems to meet legal/regulatory requirements as well as delivery of required business functionality to meet the objectives of both the lines of business and to enable the application rationalization strategy.

2012 had a reduced spend on enhancements due to a freeze on system changes as focus shifted to the implementation of the SAP Customer Information System Capital project. Costs for 2013 and 2014 include system stabilization work post SAP Customer Information System implementation and deferred system changes implementation from 2012. Also, starting in 2013, Customer Care work related to Regulatory Compliance and Service Enhancement moved from Customer Service Operations to IT. Enhancement costs for 2014 through 2019 resume for required application, data and process changes to SAP and Non-SAP systems to meet legal/regulatory requirements as well as ongoing delivery of required business functionality.

3.2 Upgrades

Hydro One utilizes approximately 875 business software applications in order to equip its employees to perform their work functions. The upgrade program provides the needed software vendors' releases, periodic version upgrades, and replacement of applications that are charged to OM&A as they do not meet the total capital threshold of $2 million.

Applications are replaced or upgraded to ensure they remain compatible with current IT platforms and other interfacing applications. In this manner, vendor support is maintained to help fix breakdowns or other issues that may occur with the application.

Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

In 2014, costs increase due to deferral of the refresh program in the previous years. These costs include refresh of iHub upgrade, Open text and Stream Serve that are required for the SAP Customer Information System. 2015-2019 planned costs include enhancement pack upgrades for modules of SAP, Trilliant Head-end system, enterprise mobile platform as well as minor upgrades to several other enterprise applications and infrastructure in order to keep them in a vendor-supported state. In 2016 and 2017, costs include upgrades to GIS and Tivoli. Costs stabilize in 2018 and 2019.

3.3 Impact of Capital Projects

This program includes business process re-engineering costs such as training and change management work efforts that are required to implement and train the line of business personnel when new or revised IT applications are introduced. These costs are associated with the IT capital projects discussed in Exhibit D1, Tab 3, Schedule 7.

In accordance with Hydro One's accounting practices, the cost associated with this implementation work (training and business process change) is not capitalized. The implementation work ensures each new business application or upgrade is properly introduced and has the necessary user understanding and support.

4.0 BUSINESS TELECOM

Business Telecom provides the data and voice telecommunications services, network operations management and field service repairs which are required for the company to operate from its province-wide locations. The business telecommunications data network is comprised of a mixture of company owned and leased facilities and equipment. Costs incurred in this area are primarily costs for third party services.

Table 5

Business Telecom OM&A Expenditures

($ Millions)

Description	Historical Years				Bridge Year	Test Years					DX Allocation				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2015	2016	2017	2018	2019
Operations and Carrier Management	5.0	5.5	5.8	7.4	7.4	7.5	7.9	8.0	8.2	8.5	3.4	3.6	3.6	3.6	3.6
Field Services	1.9	2.9	2.7	2.5	2.3	1.8	1.8	1.8	1.8	1.8	0.8	0.8	0.8	0.8	0.8
Voice and Data Network Services	10.0	10.1	9.9	9.5	8.8	8.7	8.7	8.6	8.5	8.4	3.9	3.9	3.9	3.9	3.9
Total	**16.9**	**18.5**	**18.4**	**19.4**	**18.5**	**18.0**	**18.4**	**18.4**	**18.4**	**18.6**	8.1	8.3	8.3	8.3	8.3

4.1 Operations and Carrier Management

Operations and Carrier Management costs relate to telecommunications management services provided by Hydro One Telecom (HOT) to provide telecommunications monitoring and network operations for the power system and the business operations of Hydro One. Costs reflected in Operations and Carrier Management reflect the contracted costs with HOT to provide Hydro One with telecommunication management services and operations oversight and control for its business operations. The affiliate agreement is found in Exhibit A, Tab 11, Schedule 3.

In 2011, an independent industry review was conducted which concluded that “the HOT Network Operation Center is performing networking monitoring functions at a more efficient level than comparable Canadian utilities’ 24x7 telecommunication operation.” The study also reaffirmed there are unique requirements for operating the telecommunication system of an electric utility which are not easily delivered through a third party non-electric utility carrier. The assessment process included looking at the service level agreements and statements of work for services to be covered in the regulatory review period. The report considered the revised services which will be performed in the years covered and the costs to be charged by Hydro One Telecom in providing those services.

The study states: “Cost of services increases to HONI since 2002 have been less than if the network monitoring function had remained within HONI. HOT continues to achieve efficiency gains relative to its peer group of utilities, and has now achieved the status of most efficient in performing the network monitoring function. The differentiating factor for the HONI operations as compared to the benchmarked utilities is that they have found a way to interject a commercial telecommunication approach with a solid power system telecommunication operation to bring a successful and cost effective solution to both businesses."

The report reaffirmed that Hydro One obtains cost and operations benefit through its relationship with Hydro One Telecom.

Work performed by Hydro One Telecom includes operating and monitoring the business telecom and data networks, management of security firewalls, security patching, security event monitoring, management of network interfaces with third parties, managing data and voice system problems, obtaining and managing fibre services from third party vendors, and directing other telecom service providers and vendors to change, maintain, and restore the networks as required. On an ongoing basis, this function includes managing third party supplier contracts as well as analyzing and processing bill payments to 3rd party common carriers and other telecom service providers.

Telecom service firms who provide fibre and network access include common carriers such as Bell Canada, Telus and MTS/Allstream. These companies lease telecom data and voice circuits to Hydro One at competitive market rates. The management of these services requires the contracted services of Hydro One Telecom to proactively liaise with the many carriers in Ontario and other service suppliers.

Operations and Carrier Management also provides oversight of the Bell Field Services contract as described below.

In 2013, there is an increase in cost attributed to increased work related to network and application security event management and these costs stabilize in 2014 through 2019. Over these years, to address a heightened focus on information and cyber security, HOT will be playing a critical role in security event monitoring for Hydro One's critical networks and information systems. They will use security event detection tools, and the related process and procedures, to monitor, analyze, detect and alert based on trend analysis. This investment serves to enhance the existing security monitoring and will provide a more robust monitoring, escalation and management structure.

4.2 Field Services

Field Services includes the maintenance and repair of voice and data telecom equipment. Field Services also includes the handling of connection changes for moves, additions, changes, and deletions ("MACDs"). In 2013, an RFP was issued for Field Services and awarded to Bell Canada. As a result, Hydro One realized a reduction in rates for the contracted managed service. The year-over-year cost for Field Services has decreased due to the reduction in move/add/changes to voice and data.

The agreement calls for Bell Canada technicians to be dispatched across the province to resolve any telecommunications issues. These include MACDs and preventive maintenance at any of the Hydro One sites across the province. Selected Bell Canada staff has been specifically trained to work at the Hydro One sites and facilities in order to work safely in a high voltage environment.

Costs stabilize in 2015 through 2019 based on expected moderate facilities changes and non-capital refresh work.

4.3 Voice Services and Data Network Services

Voice Services investments consist of payments made to common carriers and vendors to use and lease voice circuits and equipment. Rates charged by common carriers are competitive. Voice Services include monthly charges, usage fees and equipment rentals for voice grade business telecom (local and long distance). The local voice service rates are regulated under the CRTC. Long distance rates were secured using a competitive bid process. Annual costs are volumetric and usage-based.

Data Network Services investments consist of payments made to third party common carriers such as Bell, MTS/Allstream, and Telus to lease data network circuits and equipment at market rates. The data network is used to connect servers and computers across the province for software applications.

Hydro One continues to monitor and upgrade bandwidth as applications are deployed to field offices in order to support business processes and business requirements.

While network capacity grows each year to accommodate sharing more data among more functions, the Company has maintained cost control on data network components. Downward cost pressure is maintained through investments in efficient up-to-date IT platforms.

In 2015 to 2019 the costs for Voice and Data Network Services decrease due to contract negotiations with circuit carriers.

5.0 IT MANAGEMENT & PROJECT CONTROL

To manage the overall IT program and as the enabler and controller of IT projects, IT Management and Project Control develops and implements: IT strategies; policies and processes; IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance; and IT governance. Within the scope of these costs is work associated with hardware procurement, training, detailing vendor responsibilities, architecture development, and research services that are required to match IT solutions to known business needs for enabling business efficiencies. Work performed also includes keeping current on industry trends, product innovations, technology changes in infrastructure and applications, while researching industry best practices for future investments.

Table 6 lists the associated costs for IT Management and for Project Support and Control.

Table 6

IT Management & Project Control Expenditures

($ Millions)

Description	**Historical Years**				**Bridge Year**	**Test Years**					**DX Allocation**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2015**	**2016**	**2017**	**2018**	**2019**
IT Management	18.6	18.0	17.8	19.6	22.2	22.1	21.5	20.9	20.9	20.6	9.5	9.3	9.0	9.0	8.9
Project Support and Control	1.5	1.5	1.2	1.9	2.0	2.1	2.1	2.1	2.1	2.1	1.3	1.3	1.3	1.3	1.3
Total	**20.1**	**19.5**	**19.0**	**21.5**	**24.2**	**24.2**	**23.6**	**23.0**	**23.0**	**22.7**	10.8	10.6	10.3	10.3	10.2

5.1 IT Management

IT Management includes the cost to plan, coordinate and manage the extensive IT infrastructure and to manage the IT outsourced services. IT Management also performs work covered through needs assessment, solution architecture development, and service delivery to the lines of business.

Projects or programs that IT Management will manage or deliver include: lifecycle refresh and infrastructure upgrades; application rationalization; data architecture and data management; evolving business-technology roadmaps; ongoing security requirements and enhancements; negotiation of contracts; supporting hardware purchases for major projects and for growth; continuously improving the outsourced services; and implementation of more self-service and automation for end users.

In 2012 and 2013, costs decreased primarily due to recovery of costs from the SAP Customer Information System Capital project. In 2014, the primary reasons for the increases in cost are due to incremental resources needed to support the expanding functions of the enterprise systems such as Mobile IT, SAP, and GIS. To counter-balance this increase in ongoing work effort from 2014 to 2019 costs will be reduced by simplification of the Information Systems environment through application rationalization and creating streamlined support processes.

5.2 Project Support and Control

Project Support and Control provides standard project management services for the delivery of any and all projects impacting information systems. It provides: project management processes, templates and tools; project governance and controls of scope, quality, effort, risk and schedule; change management processes to address project-related changes affecting organizational culture, business processes, organization and job design; training to both project staff and to the users of the systems and services being delivered; and transition of projects into sustainment and ultimate closure. In 2015-2019, no increase in costs are necessary for the project management services to support the required enhancements and upgrades outlined in section 3.0

COMMON CORPORATE COSTS OM&A – COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

Hydro One Distribution directly tracks cost of sales for unregulated revenues, which includes contestable work such as: Lines - new connections and service upgrades; storm damage work; distribution generation studies; Ministry of Transportation work; and Forestry – vegetation work. These are competitive services requested by customers and are individually priced. Exhibit E1, Tab 1, Schedule 2 describes the categories of external business and associated revenues over the 2010 to 2019 period, which also relate to the level of external costs.

The cost of sales for the historical, bridge and test years (2010 to 2019) is provided below.

Table 1
Cost of Sales – Distribution External Work ($ Millions)

	Historical Years				Bridge Year	Test Years				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
New Connects & Service Upgrades	**0.3**	**0.2**	**0.3**	**0.1**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Contestable Work	**4.3**	**4.1**	**16.7**	**0.9**	**0.8**	**0.7**	**0.7**	**0.8**	**0.8**	**0.8**
Other Cost of Sales	**0.8**	**1.5**	**1.5**	**1.1**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**
Total	**5.4**	**5.8**	**18.5**	**2.1**	**2.0**	**2.0**	**2.1**	**2.2**	**2.2**	**2.2**

The costing of external work is calculated the same way as for internal work as described in Exhibit C1, Tab 4, Schedule 1.

2.0 NEW CONNECTIONS AND SERVICE UPGRADES

Costs associated with new connections and service upgrade activities are expected to be relatively consistent for the test years as shown in Table 1 above. The stability of the forecast is driven by the current economic climate, which is tempering growth in this area, as well as Hydro One Distribution's focus on the growing core distribution work program.

3.0 CONTESTABLE WORK

Costs associated with contestable work is expected to remain stable as shown in Table 1 above. This work includes activities such as Ministry of Transportation-related work and the provision of health and safety training to third parties.

4.0 OTHER COSTS OF SALES

In the test years, Hydro One Distribution is expected to incur and recover costs of approximately $1.1 million, for the provision of services to other Hydro One entities. Hydro One Distribution will not be adding a markup for providing these services to other Hydro One entities. The revenues for which this cost will be incurred can be seen in Exhibit E1, Tab 1, Schedule 2.

PROPERTY TAXES

1.0 SUMMARY OF TAXES AND FEES OTHER THAN INCOME TAX

Table 1
($ Millions)

	Historic				Bridge	Test				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Property	3.8	3.8	3.6	3.7	3.8	3.9	4.1	4.2	4.4	4.6
Indemnity Payment	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Rights Payment	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	4.6	4.6	4.5	4.5	4.6	4.7	4.9	5.0	5.2	5.4

2.0 PROPERTY TAX

Hydro One Networks Inc. is responsible for the payment of property taxes similar to every other land owner within the province of Ontario. Property taxes for Hydro One are regulated under the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Property taxes are paid on company-owned distribution lands and buildings including service centre sites, distribution transformer stations, and distribution lines. Property tax payments are made to over 400 municipalities each year by Hydro One Networks Inc.

A summary of annual distribution property taxes (including property proxy taxes) is presented in Table 2:

Table 2
($ Millions)

	Historic				Bridge	Test				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Property	3.8	3.8	3.6	3.7	3.8	3.9	4.1	4.2	4.4	4.6

The total assessed property values are assigned by the Municipal Property Assessment Corporation and are updated utilizing the same schedule as the rest of the province. Except for distribution transformer stations, all distribution properties owned by Hydro One Networks Inc. are assessed using a current value assessment method – the valuation method used for other property owners within the province.

Distribution transformer stations buildings are assessed at a statutory rate of $86.11 per square meter, per the *Assessment Act* R.S.O. 1990, Chapter A31, Section 19. Distribution transformer stations are subject to additional property tax payments, called property proxy taxes, payable to the Minister of Finance under O. Reg. 423/11 of the *Electricity Act, 1998*. Property proxy taxes are calculated for each distribution transformer station building owned by Hydro One Networks Inc. and total $0.1 million per year and are included in the property tax amount.

Notices of Assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes and overvaluations are appealed through the Municipal Property Assessment Corporation, and/or the Assessment Review Board.

Property taxes are increasing on an annual basis due to financial pressures on municipalities and school boards.

3.0 INDEMNITY PAYMENT TO PROVINCE

The Ontario Electricity Financial Corporation ("OEFC") has indemnified Hydro One with respect to the failure of any transfer orders in 1999. (Transfer orders were used to establish the company as one of the successor companies to the former Ontario Hydro.)

The OEFC indemnification covers any defects in the transfer orders encompassing the following areas:

1. the transfer of any asset, right, thing, or any interest related to the business;

2. some adverse claims or interests of third parties or based on property title deficiencies arising from the transfer orders, except for some claims and rights of the Crown, and

3. claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgement, settlement or payment in connection with litigation initiated by certain utilities commissions.

The Province has unconditionally and irrevocably guaranteed to Hydro One the payment of all amounts owing by OEFC under its indemnity.

Hydro One Networks Inc. pays an annual fee of $5.0 million to the OEFC for the aforementioned indemnification. As the transfer order primarily relates to land assets, the amount allocated to Hydro One Distribution is based on the proportion of Hydro One Distribution land assets in relation to the total land assets of Hydro One Networks Inc. This results in $0.5 million of the $5.0 million total being allocated to Hydro One Distribution.

4.0 RIGHTS PAYMENT TO OTHER ENTITIES

Through agreements or permits (approximately 950 in total), Hydro One Distribution line facilities cross and/or occupy properties owned by railway companies and/or governmental bodies. Per the terms of the individual agreements, Hydro One Networks Inc. pays annual fees to the railway companies and the government entities for the right to cross and/or occupy their properties.

A financial summary of the annual right payment fees is presented in Table 3, below:

Table 3
($ Millions)

	Historic				Bridge	Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Rights Payments	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

CORPORATE STAFFING

1.0 OVERVIEW

Hydro One continues to face the prospect of a scarcity of skilled and professional staff to operate, sustain and develop its transmission and distribution systems at a time in which a greater number of our employees are reaching eligibility and are in fact, opting to retire. Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and a world-wide scarcity of core skills in the electricity industry, in a highly competitive labour market.

This issue and associated risks are not unique to Hydro One, but apply to the Canadian electricity sector as a whole. In the Canadian electricity industry, the Power in Motion, 2011 Labour Market Information (LMI) Study, states “Between 2011 and 2016, Canada’s electricity and renewable energy industry will need to recruit 45,000 new employees – almost half of the starting workforce, and more than twice the number recruited in the last five years. Of these new employees, 23,000 will be in critical occupations that are specific to the electricity industry. Many will replace a wave of specialized and experienced retirees”.

EMPLOYEE DEMOGRAHICS

“Electricity industry workforce dynamics are notatably skewed towards a high and rising number of retiremenst that will run well above other industries” (Source: *Power in Motion - 2011 LMI Study).*

Table 1 illustrates the trend of an increasing eligibility rate for retirement and an increase in actual uptake in retirement for Hydro One employees.

Table 1
Annual Retirements

Date	# of Networks staff eligible to retire	# of Retirements	% of eligible staff
December 31, 2009	1,000	105	10.5
December 31, 2010	1,300	137	10.5
December 31, 2011	1,150	166	14.4
December 31, 2012	1,158	192	16.5
December 31, 2013	919	238*	25.8

* Retirements from Jan 1-October 1 2013

Table 2 illustrates the forecasted number of eligible retirements up to 2019.

Table 2
Annual Retirement Forecast

Date	# of Networks staff eligible to retire	Retirements Forecasted
2014	1,085	194
2015	1,322	217
2016	1,536	179
2017	1,768	176
2018	1,903	198
2019	2,036	278

To address this demographic challenge, Hydro One has been proactive by implementing a number of initiatives. These initiatives include implementation of a new People

Strategy and the continuation of a staffing strategy for the recruitment and training of new staff. These initiatives are discussed in the sections which follow.

2.0 PEOPLE STRATEGY

The Hydro One Vision is to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. To accomplish this, we require a stable workforce, top talent and highly engaged employees. The newly created People Strategy provides Hydro One's management team with a framework to help guide decision-making, inform policy and program development, and define practices, procedures, systems and collective agreements, all with a view to ensuring they are aligned, and consistent with, those of a high-performing corporate culture.

Employee Engagment and Craft of Management

Two key initiatives in support of the People Strategy are employee enagagement and the *Craft of Management***.**

Employee engagement, which is a key differentiator in terms of business success, is the extent to which employees commit to someone or something in their organization. It can influence how hard they work and how long they stay as a result of that commitment. Engaged employees provide greater discretionary effort which often leads to increased productivity and other positive business outcomes. Hydro One continues to monitor and make improvements to employee engagement.

Since 2010, Hydro One has been active in implementing the *Craft of Management* program throughout the managerial levels. The *Craft of Management* is designed to introduce managers to a comprehensive and rigorous accountability based performance management system – a system that is based on clarity of accountabilities and authorities.

The *Craft of Management* will lead to structures which better reflect the needs of the work and the accountabilities associated with the effective performance of that work, vertically and laterally within the organization. *Craft of Management* and Engagement are linked. Good managerial leadership – combined with an organization structure suitable for the needs of the work, with an effective process to allow and encourage employees to do that work, together will drive engagement.

2.1 Staffing Strategy

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. Examples would include a centralized control centre, centralized fleet operations, and an integrated asset management strategy.

Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff.

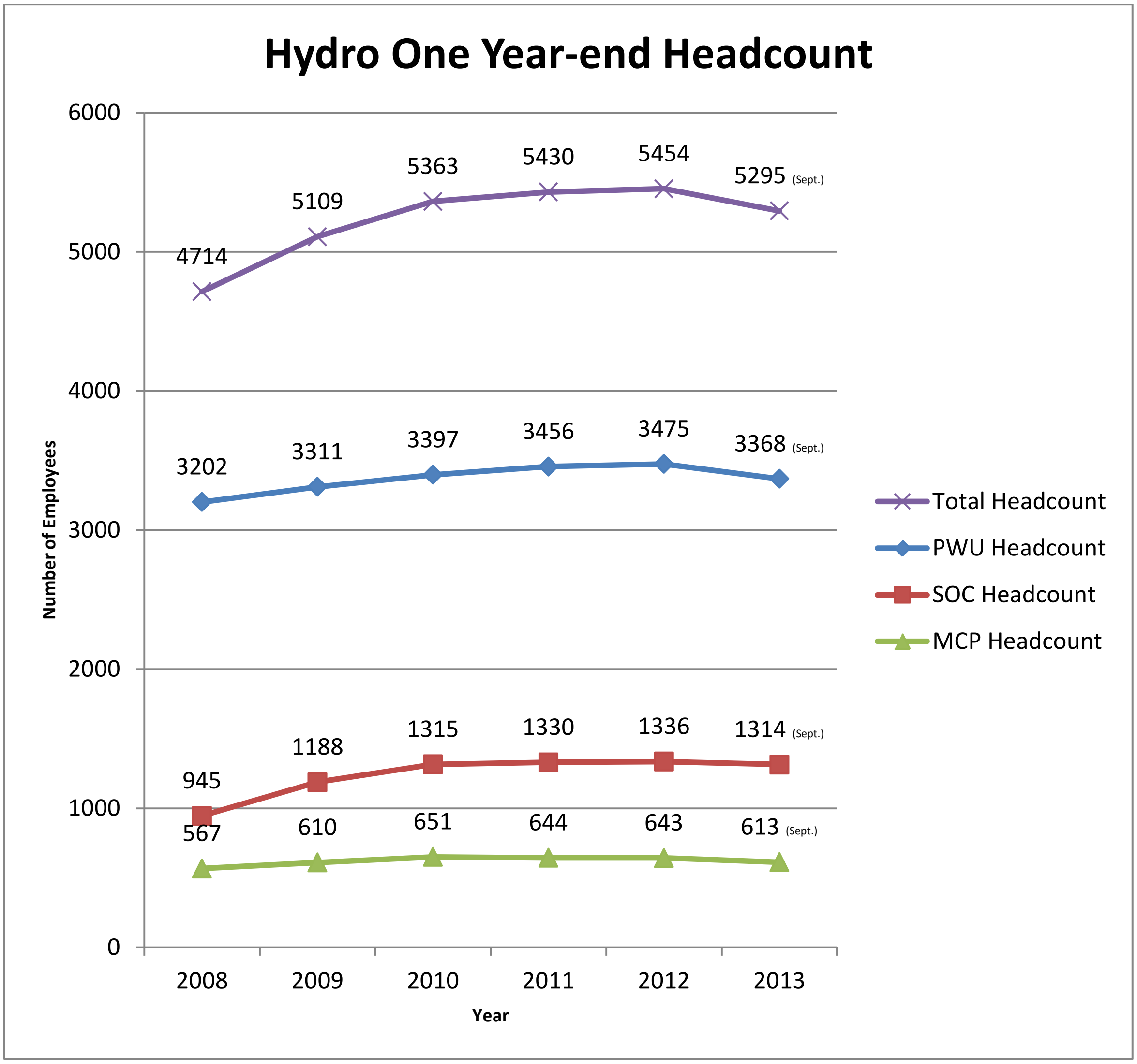
Matching staff to dynamic work programs requires a rigorous approach to staff planning. The company must consider the amount of work to be done, the nature of the work and the skills required, while at the same time looking for the most cost effective means of acquiring those skills, within the constraints of the collective agreements. Demographic and skills analyses are conducted annually to ensure that Hydro One retains the appropriate talent in the present and is positioned properly in the market to attract the talent needed in the future. In order to more accurately forecast retirements, human resources has developed a retirement forecasting model that will allow for more accurate data especially in key hiring classifications.

Progress has been made in attaining the optimal number and mix of staff required to complete the Company's increasing work programs. However, increases in Hydro One’s Transmission and Distribution programs will result in additional challenges, given the tight competition for labour and power system professionals. It is essential that the Company hires well in advance of expected retirements due to the long learning curves required for competent performance of Hydro One’s highly skilled jobs.

HEADCOUNT

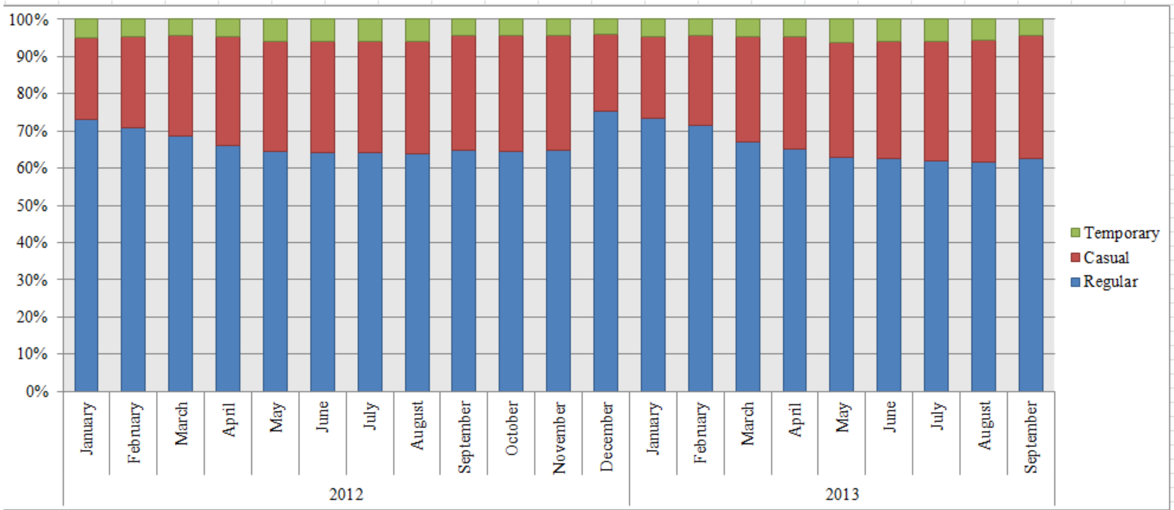
Hydro One recognizes the concerns raised in previous Decisions with respect to increasing headcount. Increases to regular headcount are tightly managed. Currently, all requests for additional regular employees must be approved by the Chief Executive Officer. Table 3 shows the year end headcount from 2008 to 2013 (September) has risen by approximaly 13%. Over the same time period, Hydro One’s work program has increased by 22%. Furthermore, regular headcount is trending downwards and in September 2013, regular headcount is less than year end 2010 levels. The business plan covering 2014-19 shows that regular headcount will continue to decrease until we reach 5000 employees.

Table 3
Annual Year-end Headcount



In order to complete the rising work program with fewer regular staff, Hydro One uses non–regular resources (Power Workers Union Hiring Hall, temporary employees, Consultants/Contractors). Table 4 illustrates Hydro One employs a large number of non–regular staff through out the year to assist with its various work programs and match fluctuating requirements from month to month.

Table 4
Staffing Profile



3.0 STAFFING

Critical to the People Stategy and ultimaltely to the success of Hydro One in meeting our customer needs, is a comprehensive and robust staffing strategy.

To help address the significant wave of retirements in critical trades, technical and engineering groups, Hydro One continues to hire, albeit at a lesser level than previous years, into its Apprentice and Graduate Training Programs. Since January 1, 2004, 440 graduate trainees have been hired through the Company's on-campus recruitment program. New Graduates bring not only much needed skills but also new perspectives and fresh energy to the work of Hydro One.

Hydro One also continues its recruitment into trades apprenticeship and technical training programs and has partnered with universities and colleges to develop curricula that educate students in areas where the Company faces a shortage of skilled professionals and trades people. Hydro One has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs and providing scholarships to encourage enrolment in key areas where the Company faces a labour shortage. Hydro One received a Partnership Award which recognizes the very successful Hydro One College Consortium. Hydro One partnered with four community colleges and provides support for scholarships, curriculum development , co-op placements and equipment to educate the next generation of energy professionals. In 2013, one of the College Consortium members launched an innovative Women in Electrical Engineering Technology (WEET) program. Hydro One's role in the WEET program will be to provide work terms for the students between their first and second year. This will provide a significant cohort of women on-the-job experience in a utility, and provide them with skills to assist in their employment upon graduation.

In addition, Hydro One, with the clear support of the PWU and the Society of Energy Professionals, has become a corporate participant in Career Bridge – a national, private-sector, non-profit initiative, which aims to provide internationally qualified professionals with Canadian work experience in their field of expertise in order to gain entry into the permanent workforce.

Hydro One will also continue its support of the University and College Co-Op Education Program, hiring approximately 300 co-op students a year. This is a mutually beneficial process in that Hydro One gains bright, skilled workers trained in the latest theories and practices for four-month or eight-month work-terms, while the students gain practical and relevant work experience that can be used to develop their future careers. Hydro One has also found that the Co-op programs have proven a rich source of talented candidates for Graduate Trainee positions by offering the Company an opportunity to assess the student's "fit" and long-term potential with the company. Once hired Hydro One's experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One experience.

External recruitment into entry level new graduate or apprentice positions has been successful. However, Hydro One has had some difficulty attracting more experienced external candidates into higher rated technical, engineering and management positions. For these positions, factors such as compensation and head office location sometimes act as barriers to successful recruitment.

Hydro One believes a more sustainable and longer term strategy to deal with large scale retirements, is to invest in programs where knowledge transfer is the key objective. Programs such as New Grad and Apprentice Hiring, and knowledge documentation all contribute to ensuring knowledge is transferred to more junior staff.

4.0 TRAINING

To address the demographic issue, it is not enough to only hire new staff. Hydro One is active in developing current staff in order to enhance and/or develop new skills.

4.1 Trades and Technical Training

Hydro One provides a comprehensive selection of trades and technical training, designed to target the specific needs of field staff in relation to the work requirements of the asset base.

4.2 Leadership and Senior Management Development

The primary objective of this program is to ensure that Hydro One has a systematic management development framework. This helps ensure the Company retains a competitive advantage by developing, maintaining, and enhancing those management competencies deemed to be essential.

4.3 Succession Planning

A Succession Planning Process has been developed for all senior management staff within the Company. The program's goal is to ensure that for each of the senior management positions, at least two successor candidates have been identified, and that a developmental plan for each of the candidates is developed and implemented.

Other human resources productivity initiatives are described in Exhibit C1, Tab 3, Schedule 2.

5.0 HYDRO ONE'S LABOUR PROFILE

As part of Hydro One's strategy to efficiently and economically manage its fluctuating work requirements, Hydro One utilizes four broad groups of staff: regular employees, temporary employees, casual workers (the Building Trade Unions -BTU's under agreements with the Electrical Power Sector Construction Association – EPSCA, the Labourers' International Union of North America - LIUNA, the Canadian Union of Skilled Workers - CUSW, and Power Workers Union - PWU Hiring Hall employees) and contract staff, discussed below.

5.1 Regular Employees

Regular Employees of Hydro One can be placed in three categories:

i) PWU represented staff: The PWU is an industrial union that represents the trades, operators, technicians and clerical workers, totaling roughly two thirds of Hydro One regular staff. They perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.

ii) Society represented staff: The Society is a professional union that represents engineers, technical, administrative and supervisory staff, totaling about one quarter of regular staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

iii) Management staff, who are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

5.2 Temporary Employees

Temporary employees are employees in any of the three categories set out above, engaged in work that is not of a continuing nature.

5.3 Casual Workers

Although the PWU does perform some construction work, the majority is performed by the PWU Hiring Hall, the Building Trades Unions (under agreements with EPSCA), and members of the Canadian Union of Skilled Workers (CUSW).

i) Hiring Hall Employees (PWU) are utilized to meet fluctuating work demands, performing primarily supplemental construction and maintenance work on the distribution system. Non-recurring work peaks and special projects are resourced through the hiring hall.

ii) Fifteen construction BTUs supply a contingent workforce through their hiring halls, negotiating their collective agreements with EPSCA. These represent the construction trades employed by Hydro One, with the exception of those represented by the CUSW.

iii) The CUSW represents lines and electrical tradespersons who work on transmission construction, including the construction of lines over 50kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. Construction employees are contingent workers, accessed through the hiring halls to perform specific work programs and then laid off. They are paid a total wage package (including benefits and pension payments) for each hour worked. This relationship ensures that workers with the required skill set are hired in the right location for only the exact duration of the work assignment and that Hydro One has no on-going obligations with respect to benefits or pension for them.

5.4 Contract Staff

Contract staff are individuals engaged as independent contractors, not on the Corporation's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions.

6.0 SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Despite the Company's efforts to ensure that it has an adequate supply of labour, it continues to face staffing challenges. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to respond to this increased workload.

In an industry with aging demographics and a highly competitive labour market, Hydro One needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide challenging and rewarding job opportunities and a competitive compensation package. Hydro One believes its staffing strategy will allow it the flexibility to respond effectively and efficiently to any scenario that will arise over the test years.

COMPENSATION, WAGES, BENEFITS

1.0 INTRODUCTION

In previous Board decisions, the Board has expressed concerns with rising compensation levels at Hydro One. In a 2006 Board Decision, Hydro One was directed to conduct a total compensation study and in a subsequent decision, the Board directed that the study be updated. At the first stakeholder session for this filing a stakeholder enquired as to whether Hydro One would be updating the compensation study. In response to this request, Hydro One initiated another study to update the two previous studies. In total, three total compensation studies have been conducted and the results show that Hydro One has succeeded in lowering total employee compensation as compared to market median. The results of this Compensation Cost Benchmarking Study are detailed later in this exhibit as Attachment 1.

While lowering compensation cost relative to market median is desirable from a rate payer point of view, the fact remains, that Hydro One must attract, and engage a highly skilled workforce, in the face of an aging workforce and worldwide competition for similar skills. Coupled with the fact that Hydro One is heavily unionized and Hydro One was created with legacy collective agreements only adds to the challenge of further reducing compensation costs.

Despite these challenges, Hydro One has been successful in balancing the competing pressures of reducing compensation costs relative to market median at the same time as attracting and maintaining an engaged workforce. Ultimately, the rate payers benefit from the quality, expertise and reliability of Hydro One employees.

2.0 TOTAL COMPENSATION STUDIES

In EB-2006-0501, the Board directed Hydro One to file a total compensation study that "will provide useful and reliable information concerning Hydro One's compensation costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America". Following stakeholder sessions to obtain input on how this study would be conducted, Mercer undertook a Compensation Cost Benchmarking Study (the "2008 Study") and the results were filed in EB-2008-0272.

In EB 2010 -0002, the Board directed Hydro One "to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. Further stakeholder sessions took place and Mercer once again conducted a total compensation study (the "2011 Study") that was filed in EB-2012-0031.

Responding to a stakeholder request for an updated study in this current application, Hydro One requested Mercer to conduct another study (the "2013 Study").

Table One compares the study results for all three studies.

Table 1
Mercer Compensation Benchmarking Study Results vs. Market Median
Total Compensation

Employee Group	2013 Survey Results	2011 Survey Results	2008 Survey Results	Total Change from 2008 to 2013
Management	-1%	-17%	-1%	0%
Society	9%	5%	5%	4%
PWU	12%	18%	21%	-9%
Overall	10%	13%	17%	-7%

The 2013 study findings show that on an overall weighted average, Hydro One is positioned approximately 10% above market median. This is an improvement relative to the 2008 Mercer study where Hydro One's overall weighted average was found to be 17% above market median. Mercer stated the shift towards market median was notable, especially given the peer group, like Hydro One, had worked to minimize labour costs through the substantial economic downturn which began in 2008. In other words, Hydro One improved its standing against others in the peer group who were also attempting to reduce compensation costs.

For the individual groups, Hydro One management classifications surveyed were found to be 1% below market median. Compared to the 2011 study, this shows that non-represented compensation has moved toward market median. The 2011 study result was mainly due to the impact of a two year wage freeze on non-represented compensation. The 2013 study results would indicate that non-represented classifications are closer to the desired non-represented compensation policy of being at the 50th percentile. Professionals (Society of Energy Professionals – "the Society") classifications were found to be 9% above market median. Power Workers' Union (PWU) represented classifications were found to be 12% above market median, a significant improvement from the 2008 result of 21% above market median reflecting the increased use of hiring hall staff and the increased pension contributions negotiated as part of the new collective agreement.

3.0 THE UNIONIZED ENVIRONMENT

Approximately 90% of the Hydro One work force is unionized. Hydro One has collective agreements with the Power Workers' Union (PWU), The Society of Energy Professionals (The Society), the Canadian Union of Skilled Workers (CUSW), and each of the 15 Building Trade Unions (BTUs) (via EPSCA).

The collective agreements establish the terms and conditions of the employment relationship for a fixed period of time. It is critical to understand that Hydro One inherited collective agreements from Ontario Hydro which established terms of employment. These legacy collective agreements established a 'floor' upon which future negotiations were based. While legacy collective agreements continue to strongly influence current Hydro One collective agreements, Hydro One has done much to change the status quo. Hydro One has been successful in incrementally reducing costs and/or increasing productivity through collective bargaining. Obtaining dramatic compensation reductions in the environment facing Hydro One is unrealistic.

Collective Agreements are legal contracts. In labour agreements, more so than commercial contracts, parties must also consider their longer term relationship. Hydro One's Human Resources strategy is to negotiate fair and reasonable collective agreements to foster and promote healthy union–management relationships.

4.0 COLLECTIVE BARGAINING

4.1 PWU

The PWU represents over 70% of Hydro One employees. The PWU is an industrial union that represents the trades, controllers, technicians and clerical workers. Its members perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.

An attempt by Hydro One to achieve significant cost reductions in wages, benefits and pension would likely result in a strike. The last PWU strike was in 1985 and lasted 12 days. It was handled by placing management and Society-represented staff in key functions to maintain operations/service to the extent possible. However, as a result of numerous downsizing programs, and reorganization of work, there is fewer management staff available today with the requisite skills and experience to occupy key PWU positions during a strike. Furthermore, unlike other industries, Hydro One does not have a product that can be stockpiled. As a result, the Company would be unable to continue operations for a sustained period of time during a PWU strike.

Rather than risk jeopardizing the supply of reliable electricity, the company has sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations, as opposed to wide scale reductions in wages, benefits and pensions.

4.2 The Society of Energy Professionals

The Society represents approximately 20% of Hydro One employees. Society-represented staff performs engineering, high level technical and administrative work as well as supervisory functions. The majority of the Society-represented employees in Hydro One have either post-secondary education (university degrees) and/or post-graduate education. These include graduate engineers, finance and telecommunication specialists.

In 2005, the Society initiated a fifteen week strike in response to Hydro One's desire to reduce wages and benefits and increase hours of work for new employees. Hydro One was requested by the Shareholders to enter into mediation–arbitration to end the strike. The arbitration award resulted in some cost savings for future hires, highlighted with less costly pension provisions for new Society employees.

5.0 COLLECTIVE BARGAINING

The collective bargaining relationships at Hydro One are very complex and sophisticated. Hydro One and the bargaining agents with whom the Company negotiate are professionals and very seasoned in the area of collective bargaining. Hydro One has been able to achieve reasonable settlements with incremental cost reductions and increased flexibility in a variety of areas in every round of collective bargaining since 2001. Examples include:

- elimination of costly incentive pay plans
- reasonable economic increases;
- reductions and cost containment in benefit improvements;
- introduction of new salary schedules with lower starting rates and lower maximum rates;
- introduction of a less costly pension plan;
- increased employee pension contributions;
- increased flexibility to contract out work;
- reduction in the hourly rate for a variety of jobs;

- increased flexibility to move staff;
- increased utilization of contingent workers;
- introduction of less costly classifications;
- greater shift scheduling flexibility; and
- reduction in temporary work headquarter costs.

5.1 Recent Negotiation Highlights

5.1.1 <u>PWU Negotiations</u>

In 2013, a new 2 year collective agreement was successfully negotiated by the bargaining committees of Hydro One and the PWU and ratified by the PWU-represented staff. The term of this collective agreement ends on March 31st, 2015. Modest economic increases were negotiated (2.5% in each year). To lessen the cost impact of these increases, they were phased in on April 1st and October 1st in 2013 and 2014.

Employee pension contributions were also increased. In the last Transmission Decision, the Board commented that it expects to see demonstrated measurable progress towards increasing employee pension contributions. The Board stated that “Hydro One must demonstrate measurable progress towards having its pension contributions reflect those prevailing in the public sector generally. The evidence suggests that an employee contribution level of 50% is the norm”. In 2011, Hydro One negotiated a 0.5% increase to the PWU employee pension contributions and in the most recent negotiations, employee contributions have increased by a further 0.75% in 2013 and 1.0% in 2014.

To address rising benefit costs, the parties agreed to the requirement to use mandatory generic prescribed drugs and to establish a joint committee to make recommendations to reduce costs in the area of biological and other expensive drugs.

Increased resourcing flexibility was achieved by negotiating enhancements to use more temporary staff and to contract out more work.

5.1.2 Society Negotiations

In 2013, a new three year collective agreement was successfully negotiated by the bargaining committees of Hydro One and the Society and ratified by the Society-represented staff. The term of this collective agreement ends on March 31st, 2016.

Modest economic increases were negotiated (2%, 2% and 2.25%). Employee pension contributions were increased by 0.75%, 1% and 0.75% in each year of the term of the collective agreement.
Increased flexibility was achieved by increasing the length of new hire probationary periods and formalizing the deletion of the Purchase Service Agreement so that contracting out can be fully utilized when appropriate.

6.0 MANAGEMENT (MCP) COMPENSATION

Changes to management compensation are wholly at the discretion of senior management. The management compensation structure is comprised of two key components:

1. Merit pay which recognizes competency, performance and retention risk; and
2. A short term incentive (STI) program, which is discretionary and is based on the Hydro One Board and Senior Management's assessment of achievement of the corporate scorecard and achievement of individual performance agreements.

The *Broader Public Sector Accountability Act (BPSAA) 2010* froze all management compensation from 2010 to 2012. The 2012 Ontario Budget amended this Act so that compensation for Vice President's and above are frozen until such time that there is no deficit in the Budget.

Since the wage freeze legislation expired for management positions below the Vice President level, Hydro One has had a limited base wage program in 2013. A rigorous process was used to align pay for performance by considering a number of factors such as overall performance, engagement scores, pay relative to performance of peers and potential flight risk. In 2013, all MCP employees increased their pension contributions by 0.75%.

In 2014, MCP employees will be eligible for a merit pay program. A 2.5% merit pay adjustment fund was established for Director level employees and below. The merit program once again will align pay and performance and will be allocated in a manner that differentiates between levels of performance. This is not an across the board 2.5% increase for all MCP staff. Once again, all MCP employees will have their pension contributions increased by another 0.75%.

7.0 COMPENSATION STRATEGY

Hydro One has experienced rapidly increasing transmission and distribution work programs since 2004. Resourcing of these work programs must occur on the most cost effective basis possible within a highly competitive labour market.

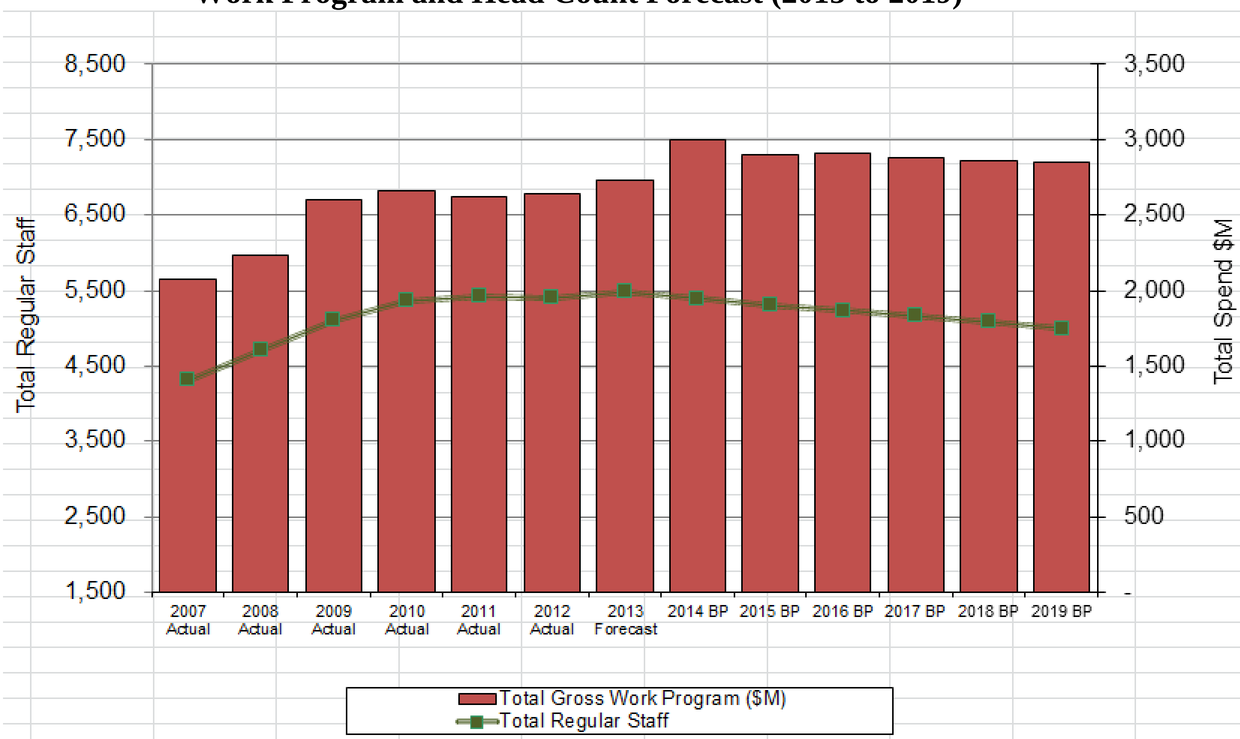
Attachment 2 provides year end compensation costs for Hydro One Networks (Transmission and Distribution) from 2010 to 2012 and forecasted year end compensation cost for 2013, the bridge year (2014) and test years (2015-2019). The

Company believes that the upward trend in these costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2004, as well as the negotiated increases in labour rates.

Note this data represents year end payroll costs for Hydro One Networks in total (i.e. Distribution and Transmission). The purpose of this table is to illustrate the trend in compensation costs.

For the period 2014-2019, the total Networks (Transmission and Distribution) work program is expected to decrease by approximately 4.9% while the regular headcount is expected to decrease by 7.5% by year end 2019.

Table 2
Work Program and Head Count Forecast (2015 to 2019)



Hydro One believes that the goal of reducing overall wages, pension and benefits for future new hires reflects a reasonable balance between the need to attract and retain new staff while pursuing a more favourable cost structure. This is a difficult balance to achieve. Too much of a reduction in compensation and benefits will impact the ability to attract the new skills necessary to replenish the workforce. However, as outlined in Exhibit C1, Tab 3, Schedule 1, as the proportion of Hydro One staff qualifying for and taking early retirement is growing substantially, the goal of reducing compensation for future new hires will reduce overall compensation costs for Hydro One and its ratepayers.

Hydro One's best performers are highly marketable, and a number of management staff have left the company in recent years. The Hydro One succession plan has facilitated internal promotion and a smooth transition in most cases, but our internal replacement capacity is now significantly diminished in key areas. External recruitment has proven challenging as our compensation levels and structures have fallen below the market for top people.

8.0 COMPARISON OF COLLECTIVE AGREEMENTS

When assessing the prudency of Hydro One's collective agreements, a useful comparison is the compensation wage scales for similar PWU (table 3) and Society (table 4) classifications in the Ontario Hydro successor companies as Hydro One competes for staff with these companies and is vulnerable to losing staff to these organizations. Such a comparison is instructive since all these wage scales have the same starting point, which is the establishment of the successor companies in 1999. It is important to compare compensation escalation based on total "dollar" base rates of similar classifications. Simply comparing accumulated base rate percentage increases does not capture the true difference between total base compensation paid at the successor companies.

In the two wage scale comparison tables for each of PWU and Society staff which follow the wage scale rates shown are for the top end of the wage scale band.

As shown in Table 3 for PWU staff, Hydro One has negotiated substantially lower wage scales than OPG and Bruce Power for all seven positions with the exception of one.

Table 3
Power Workers' Union – Wage Comparisons, 1999 and 2013

	1999	2013	Percent Change
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One	$ 28.23	$ 42.48	50 %
OPG	$ 29.08	$ 50.08	72 %
Bruce Power	$ 29.08	$ 57.10	96 %
Shift Control Technician/Regional Maintainer – Electrical			
Hydro One	$ 28.23	$ 42.48	50 %
OPG	$ 30.31	$ 50.08	65 %
Bruce Power	$ 30.31	$ 57.27	89 %
Clerical – Grade 56 (based on a 35-hour work week)			
Hydro One	$ 21.46	$ 32.30	51 %
OPG	$ 21.46	$ 31.99	49 %
Bruce Power	$ 21.46	$ 35.59	66 %
Clerical – Grade 58 (based on a 35-hour work week)			
Hydro One	$ 24.20	$ 36.42	50 %
OPG	$ 24.20	$ 38.95	61 %
Bruce Power	$ 24.20	$ 40.13	66 %
Regional Field Mechanic/Transport & Work Equipment Mechanic			
Hydro One	$ 26.20	$ 39.43	51 %
OPG	$ 26.20	$ 50.08	91 %
Bruce Power	$ 26.20	$ 49.71	90 %

Stockkeeper			
Hydro One	$ 23.27	$ 36.75	58 %
OPG	$ 23.27	$ 38.95	67 %
Bruce Power *	$ 23.27	$ 44.88	93 %
Labourer			
Hydro One	$ 19.03	$ 28.63	50 %
OPG	$ 19.03	$ 38.95	105 %
Bruce Power *	$ 19.03	$ 44.88	136 %

* Assumes that the position falls within the Civil Maintainer II classification and corresponding wage rate

Table 4
Society of Energy Professional – Wage Comparisons 1999 and 2013

	1999	2013	Percent Change
MP2			
Hydro One	$ 77,954.79	$ 100,078.50	28 %
OPG	$ 77,954.79	$ 101,333.39	30 %
Bruce Power	$ 77,954.79	$ 102,113.46	31 %
IESO	$ 77,954.79	$ 118,068.03	51 %
MP4			
Hydro One	$ 88,651.39	$ 113,801.46	28 %
OPG	$ 88,651.39	$ 115,171.67	30 %
Bruce Power	$ 88,651.39	$ 116,045.14	31 %
IESO	$ 88,651.39	$ 134,218.03	51 %
MP6			
Hydro One	$ 100,756.80	$ 129,350.68	28 %
OPG	$ 100,756.80	$ 130,950.99	30 %
Bruce Power	$ 100,756.80	$ 131,907.42	31 %
IESO	$ 100,756.80	$ 152,617.49	51 %

For Society staff, Hydro One, OPG and Bruce Power have successfully negotiated lower end rates as compared to the PWU wages. However, for all three Society categories, Hydro One has lower wage scales than OPG and Bruce Power. The IESO has continued with the wage schedule structure that existed at demerger.

It is quite clear that compared to these four other companies, Hydro One has been quite successful in controlling costs in collective bargaining over the past ten years to the benefit of all ratepayers.

9.0 POWER LINE TECHNICIAN RATE COMPARISON

Within Ontario, the largest LDCs are Hydro One Networks Inc., Toronto Hydro Electric System Limited, Hydro Ottawa Limited, Enersource Hydro Mississauga Inc., London Hydro Inc., Horizon Utilities Corp. and Powerstream Inc. Each of the LDCs employ Power Line Maintainers (PLMs). Table 5 compares the PLM rate at each of the LDCs to the PLM rate paid at Hydro One Networks. The PLM classification was chosen since it represents a highly skilled and highly populated classification that is core to the other LDCs.

Table 5
POWER LINE MAINTAINER WAGE COMPARISON

Company	Classification	Wage – 2012($hr)	H1 % Difference
Hydro One	Power Line Maintainer	38.75	-
Toronto Hydro	Power Line or Cable Person	40.26	-3.9%
Enersource	Power Line Technician	38.95	-.5%
Powerstream	Linesperson	38.31	+1.1%
Horizon	Power Line Maintainer	37.88	+2.3%
London Hydro	Power Line Maintainer	36.42	+6.0%
Hydro Ottawa	Power Line Maintainer	36.53	+6.0%

Hydro One uses a multi-skilled position called a Regional Maintainer–Lines classification (RLM). The RLM uses the PLM as the base job with additional duties such as lead hand, contract monitor, establishment and holding of work protection as well as additional technical, trade and customer relations skills beyond the Power Line Maintainer classification.

Table 4 illustrates that the PLM rate at Hydro One ranges from being slightly below to slightly above the larger LDCs in Ontario. Despite the rates being very close, the type of work and skills required at Hydro One are often more complex. Hydro One employees often work in a more rural setting than their counterparts in other LDCs. As a consequence, Hydro One employees can work in conditions and with equipment not normally required at these LDCs. Trades employees working on lines maintenance often work on both Distribution and Transmission assets and are required to be knowledgeable and proficient with overhead, underground and submarine cable. Again, this is not typical of the PLM role in other Ontario LDCs.

10.0 SUMMARY

Compensation levels at Hydro One are reasonable and appropriate given the environment in which the Company operates. In recent years, despite significantly increased work volumes, overall costs have been minimized by the simplification of required job skills and pay levels where appropriate. Hydro One's demographic challenge requires the Company to be active in the labour market and with worldwide competition for these skills there is a need for competitive compensation.

The updated Mercer Total Compensation Benchmarking Study demonstrates that there has been a significant improvement in total compensation costs at Hydro One relative to market median. It is important to emphasize that in a time where other organizations are facing similar cost pressures, Hydro One has lowered its overall total compensation from 2008 to 2013 by 7% against the peer group.

A strong barometer of Hydro One’s ability to restrict compensation increases is a direct comparison to companies such as OPG, Bruce Power, and IESO. Hydro One competes directly with these organizations for skilled workers. Hydro One is also at risk of losing experienced staff to these organizations if our compensation is not competitive. Despite these competitive pressures, Hydro One has negotiated compensation levels that are less costly than OPG, Bruce Power and the IESO.

In addition, in a heavily unionized environment, there are significant constraints on an employer’s ability to reduce compensation costs per employee. However, despite these constraints, the Corporation has made gains with the reduction in the area of compensation and benefit reductions.

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TALENT • HEALTH • RETIREMENT • INVESTMENTS

COMPENSATION COST BENCHMARKING STUDY

HYDRO ONE NETWORKS INC.

09 DECEMBER 2013

MARSH & McLENNAN COMPANIES

CONTENTS

1

Executive Summary

Hydro One Networks Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was conducted in 2008 and 2011, and repeated, following a similar methodology, in 2013. Year-over-year trend analysis is provided.

The preliminary results of our analysis were presented at the October 16, 2013 stakeholder session in Toronto. This document represents the results of our analysis. Specifically:

Compensation Benchmarking

Consistent with the Stakeholder feedback, the compensation benchmarking component of the study compared Hydro One with the 2011 Transmission, Distribution and Generation market peer group, supplemented with participants from the Similar Regulatory Environment group.

The study reflected approximately 3,050 Hydro One employees in 32 benchmark positions representing 57% of Hydro One's employee population (excluding non-full time employees). In total, our analysis reflected approximately 14,000 incumbents employed in the Canadian energy and/or adjacent sectors.

On an overall weighted average basis, for the positions we reviewed in 2013, Hydro One is positioned approximately 10% above the market 50th percentile ("P50"). In comparison to the 2011 study, Hydro One's overall weighted average positioning has decreased from 13% above the market total compensation P50.

The shift in Hydro One's competitive position towards the median is notable given that the peer group, like Hydro One, has worked to reduce labour costs as a response to both the substantial economic downturn beginning in 2008 and expectations of key stakeholders over the entire period between the 2008 and 2013 during the compensation cost benchmarking studies.

The overall Hydro One positioning is driven by a combination of competitive base salaries, especially for the most highly skilled Power Workers' Union ("PWU") positions and Professionals ("Society") members, and the high relative value of legacy, pension and benefits programs (the legacy Management pension and benefit and Professional pension plans are now closed to new members).

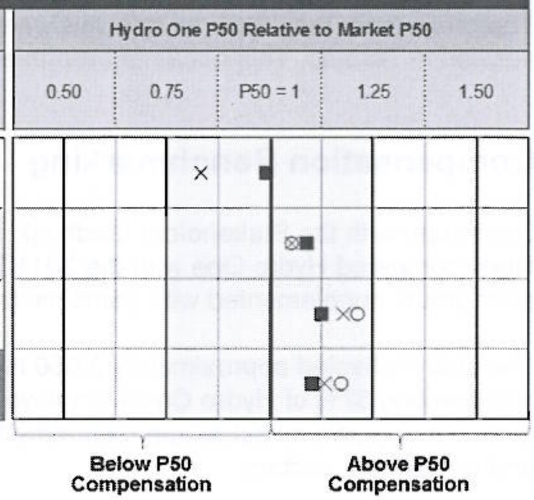
The table below summarizes the results of the 2013 Compensation Cost Benchmarking Study compared to the results of the 2011 and 2008 study.

Table 1

Legend
- ■ 2013 Hydro One Position Relative to Market
- X 2011 Hydro One Position Relative to Market
- O 2008 Hydro One Position Relative to Market

Total Remuneration (Current)

	Hydro One Group	# of Hydro One Incumbents	Multiple of P50 2013	Multiple of P50 2011	Multiple of P50 2008
Weighted Average	Non-Represented	*206*	0.99	0.83	0.99
Weighted Average	Professionals	*746*	1.09	1.05	1.05
Weighted Average	Power Workers	*2,100*	1.12	1.18	1.21
Weighted Average	*Overall*	*3,052*	*1.10*	*1.13*	*1.17*



2

Introduction

Hydro One Networks Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was conducted in 2008 and 2011, and repeated, following a similar methodology, in 2013. Year-over-year trend analysis is provided.

This report is intended to help Hydro One in preparing a two year Cost of Service application for Transmission rates (2015-2016) and a five year Custom Cost of Service Application for Distribution (2015-2019). The results of the Compensation Cost Benchmarking study will be filed as evidence for both rate setting applications.

To provide independent and reliable information on Hydro One's relative compensation costs, Mercer has undertaken a customized survey of total compensation costs in the market ("Compensation Benchmarking").

The total compensation (i.e., base salary, short-term incentives, long-term incentives, pension and benefits) benchmarking analyses focused on assessing Hydro One's overall competitiveness in the marketplace.

3

Guiding Principles

Based on our typical benchmarking approach and the benchmarking principles that guided the compensation benchmarking, as well as how Mercer applied them, these include:

1. Principle objective – to revisit the 2011 and 2008 Mercer Study to reasonably compare Hydro One compensation costs to those of regulated utilities in Canada.
   - The 2011 and 2008 Mercer Studies were revisited following the same general overall methodology to provide appropriate study-over-study comparisons.

2. Keep it simple to entice survey participants.
   - The data collection process was reviewed and streamlined, where possible, to encourage survey participants to share data. Additional follow-up was provided by Mercer to support comparator participation in the study.

3. Be independent, testable, repeatable and market-based.
   - The study was conducted in a manner that meets each of the criteria listed.

4. Provide participants with the assurance that their information could not be attributable to them.
   - All participants were assured that data would be held confidentially by Mercer and only be shared in aggregate form.

5. Be based on the groups surveyed in the 2011 Mercer Study and expanded as deemed appropriate by the consultant.
   - The 2013 study targeted the same benchmark jobs and organizations as the 2011 study. Three (3) organizations were also added to the 2011 invitation list, in addition to the organizations that were invited to participate in 2011. This resulted in a total of four (4) new participants in the 2013 study – the three (3) new organizations noted above plus one (1) organization that was invited to participate in 2011 and declined at that time.

6. Mirror the scoping in the 2011 and 2008 Mercer Studies for peer selection, job classes, etc. and changes as deemed appropriate by the consultant.
   - The same methodology used in 2011 and 2008 was followed in the 2013 Mercer Study for both peer company selection and job classes for inclusion. As noted in 5. above, four (4) additional comparator companies were added to the peer group. The selected benchmark job classes represented 57% of Hydro One's employee population (excluding non-full time employees), an increase over the 2011 study.

7. Enable reasonable comparison to the last Mercer study and provide trending analysis for Hydro One.
   - By including approximately 85% of peers and 94% of jobs from the 2011 Mercer Study, reasonable comparisons have been made and trending has been assessed.

8. Compare to market median rather than market average
   - The 2013 Mercer Study is based on a comparison of Hydro One median compensation against market median compensation. Comparison of medians is standard compensation practice; medians are representative of the middle data point in a sample and are less sensitive to outliers than the mean.
     - The 2008 and 2011 studies also compared Hydro One to the median.
   - Appendix A provides a comparison of Hydro One's total compensation median against market average. On an overall weighted average basis, there is no difference in Hydro One's median positioning relative to market median and market arithmetic mean.

9. No adjustments to reflect regional costs of living amongst the study participants.

10. Request data about pension as a percentage of total benefits, and benefits as a percentage of compensation.
    - It is standard benchmarking practice to assess benefits and pension costs as part of the total compensation value provided to employees; therefore, we have not provided the details of this analysis showing benefit and pension separately.

11. Rely on the expertise of the selected consultant to recommend appropriate changes in methodology and assumptions.
    - Hydro One relied on Mercer's expertise in conducting the study.

4

Compensation Benchmarking

Peer Groups

Mercer selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer establishes limits of 33% to 300% of the scope criteria for the organization we are analyzing. Some organizations were included in the analysis despite falling below the 33% of revenue threshold value. These organizations were primarily Ontario based local distribution companies that are seen as important benchmarks by stakeholders.

As a result, to develop a single peer group for Hydro One, we considered all organizations, with 2011 or 2012 annual revenues or total assets between 33% and 300% of Hydro One's 2012 annual revenue or total assets, from the following areas:

1. Electric utilities, multi-utilities, generators, and gas utilities industries in Canada as classified by their Global Industry Classification Standard ("GICS")

2. 73 Local Distribution Companies ("LDCs") in Ontario

3. Other comparable regulated businesses (i.e., integrated telecommunication services, railroads, etc.)

Overall, 24 organizations were invited to participate in the study:

- All 13 organizations included in the 2011 study were invited
  - Of these organizations, 2 declined (Altalink, Canadian Utilities)
- Three new organizations were invited
  - Of these organizations, 2 agreed to participate (Enersource Corporation, Horizon Utilities Corporation)

Organizations that did not participate in the compensation benchmarking indicated that they were unable to participate due to either resource constraints or an insufficient number of relevant benchmark positions.

Following standard industry practice, comparisons were made between Hydro One's incumbents, at the 50th percentile, to the market peer group 50th percentile on base salary, total cash compensation and total compensation.

To ensure that no one organization biased the results, we have weighted our analysis by organization for each job class and not by incumbents to determine Hydro One's position relative to the market (i.e., the analysis is "Org Weighted"). To preserve the confidentiality of compensation data at both Hydro One and participating organizations, we have aggregated our results.

Market Sample

Summarized below are the participating organizations in the compensation benchmarking.

Table 2

Company Name	Revenue[1]	# of Employees[1,2]
Hydro-Québec	$12,228.0	21,000
BC Hydro Power & Authority	$4,898.0	5,862
Ontario Power Generation Inc.	$4,732.0	10,691
EPCOR Utilities Inc.*	$4,036.0	4,036
ENMAX Corporation	$3,160.1	1,840
Toronto Hydro Electric System Ltd.	$2,852.0	1,526
Enbridge Gas Distribution Inc.	$2,400.0	2,200
TransAlta Corporation	$2,262.0	3,140
Bruce Power L.P.*	$2,103.7	4,200
Manitoba Hydro	$1,902.0	6,637
SaskPower	$1,862.0	3,000
New Brunswick Power	$1,697.0	2,361
PowerStream Inc.	$1,029.0	541
Enersource Corporation*	$822.0	374
Horizon Utilities Corporation*	$570.6	404
75th %ile	**$3,598.1**	**5,031**
50th %ile	**$2,262.0**	**3,000**
25th %ile	**$1,779.5**	**1,683**
Average	**$3,103.6**	**4,521**
Hydro One	**$5,728.0**	**5,337**

[1] *Data as reported by survey participants in CAD ($MM)*

[2] *Representative of full-time employees and equivalents only*

* *New participants in 2013*

Benchmark Positions

The compensation survey was designed to benchmark compensation levels from a cross-section of Hydro One's population. To determine the roles to be included in our benchmark analysis, we reviewed positions that represented all of Hydro One's major business units and at least 50% of Hydro One's employee population.

To assist with study over study comparisons, it was determined that Hydro One should collect incumbent data using 33 of the same benchmark roles surveyed in the 2011 study. Due to limited data in the market from previous years, the following role was not surveyed in 2013:

- Tree Trimmer - Journeyman (Power Workers)

In total, 33 benchmark positions were included in the compensation benchmarking study and we were able to report data on 32 of these job. Due to limited data in the market, the following role was excluded from the final analysis:

- Regional Maintainer - Forestry

As a result, ***the 2013 Compensation Cost Benchmarking Study directly reflected approximately 3,050 Hydro One employees in 32 benchmark positions representing 57% of Hydro One's employee population (excluding non-full time employees).***

In the market, we collected approximately 14,000 individual incumbent observations across the benchmark positions (excluding the 3,050 Hydro One incumbents) ***employed in the Canadian energy and/or adjacent sectors.***

Summarized below are the benchmark positions organized by major employee group. The results in this report are summarized by the following employee groups. Specifically (sorted in descending total compensation by Group):

Table 3

Hydro One Group	Job #	Benchmark Survey Title
Non-Represented	1	Financial Director
	2	Top Rates and Regulatory Affairs Executive
	3	Senior Legal Counsel
	4	Engineer F
	5	Area Superintendent
	6	Human Resource Manager / Consultant
	7	Field Service Coordinator
	8	Administrative Assistant
Professionals	9	Engineer E
	10	Business Analyst C
	11	Engineer D
	12	Engineer C
	13	Engineer B
	14	Business Analyst A
	15	Engineer A
Power Workers	16	System Operator (Controller)
	17	Regional Maintainer - Lines (Supervisory)
	18	Protection and Control Technician
	19	Area Distribution Engineering Technician
	20	Regional Maintainer - Lines
	21	Regional Maintainer - Electrical
	22	Fleet Mechanic
	23	Lineman - Journeyman
	24	*Regional Maintainer - Forestry**
	25	Service Dispatcher
	26	Drafter II
	27	Stock Keeper
	28	Data Entry Clerk
	29	Production Field Administrator III
	30	Electrical Apprentice
	31	Lines Apprentice
	32	Meter Reader
	33	General Labourer/Roustabout

**Insufficient data to report*

"Professionals" refers to Hydro One positions represented by the Society of Energy Professionals (i.e., "Society") and "Power Workers" refers to Hydro One positions represented by the Power Workers' Union (i.e., "PWU").

See Appendix B for a summary of position descriptions.

Methodology

As outlined in Appendix B, summarized below is the methodology used to determine compensation levels. Specifically:

Base Salary/Wage – Annual base salary at July 1, 2013. If an hourly rate was reported, we annualized the value by multiplying the standard number of work hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

- Data effective July 1, 2013 captures Hydro One's most recent collective agreement terms.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid where applicable.

- Hydro One does not provide short-term incentive or bonus programs to Professional or Power Worker positions.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans.

Total Compensation – Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

- Hydro One does not provide long-term incentive programs to any positions.

Findings

Summarized below are the results of our compensation benchmarking analysis.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 10% above market median**. Hydro One's position relative to the market 50th percentile varies by employee group from a low of 1% below market P50 for the non-represented group and a high of 12% above the market P50 for the PWU.

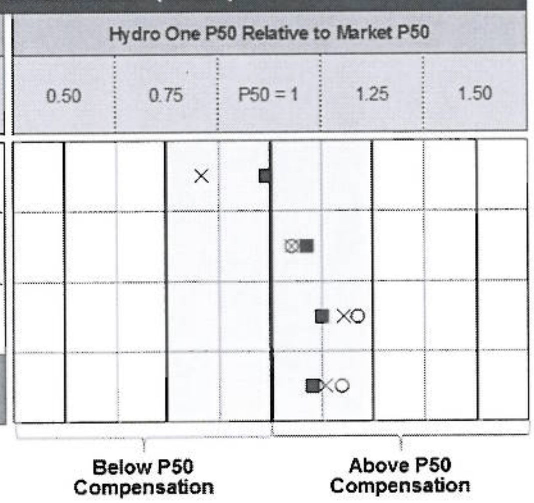
In the 2011 study, Hydro One's overall weighted average was 13% above the market total compensation P50 – a 3% shift towards the market median has occurred since 2011.

Table 4

Legend
- ■ 2013 Hydro One Position Relative to Market
- X 2011 Hydro One Position Relative to Market
- O 2008 Hydro One Position Relative to Market

Total Remuneration (Current)

	Hydro One Group	# of Hydro One Incumbents	Multiple of P50 2013	Multiple of P50 2011	Multiple of P50 2008
Weighted Average	Non-Represented	206	0.99	0.83	0.99
Weighted Average	Professionals	746	1.09	1.05	1.05
Weighted Average	Power Workers	2,100	1.12	1.18	1.21
Weighted Average	Overall	3,052	1.10	1.13	1.17



The results are driven by a combination of competitive base wages, especially for the most highly skilled Power Workers' Union ("PWU") positions, and the relatively high value of legacy collective agreement wages, pension and benefits programs (the legacy non-represented pension and benefit and Society pension plans are now closed to new members).

We understand that these legacy plans relate to collective agreements negotiated prior to the formation of Hydro One. All PWU employees continue to be covered by the legacy plans. Even if all Non-Represented and Professional employees were covered by the new plans, the difference in overall cost on a weighted average basis appears to be minimal as the high population Power Worker positions continue to be covered by the legacy plans; however, the use of the "hiring hall" for several of the PWU benchmarks does appear to reduce compensation costs relative to both other PWU positions and our market data.

For new employees hired into Non-Represented and Professional job classifications, the value of pensions and/or benefits, where applicable, have decreased due to recent amendments to these plans (see "Future" column on the following pages).

We note that, when measured on revenue, Hydro One is the second largest organization in the sample. Although size has a limited impact on middle management and unionized roles, size may have an impact on compensation for executive roles, as these roles tend to be larger and more complex in larger organizations.

As requested by stakeholders in 2011, in addition to comparing Hydro One P50 to market P50, a comparison was also made of Hydro One median to market average (mean). On a weighted average basis, Hydro One's total compensation cost is 10% above market average. Hydro One's position relative to market varies by employee group from a low of 3% below market average for the non-represented group and a high of 13% above the market average for the PWU. In conclusion, there is relatively little difference between the market median and market average. See Appendix A for detailed results.

Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation (Current) results have increased from 17% below market median to 1% below market median.

Table 5

			Hydro One P50 Relative to Market P50[1]			
					Total Compensation[3]	
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Current[4]	Future[5]
Non-Represented	Financial Director	3	3%	20%	21%	21%
Non-Represented	Top Rates and Regulatory Affairs Executive	4	-5%	-5%	-1%	-3%
Non-Represented	Senior Legal Counsel	8	-7%	0%	12%	6%
Non-Represented	Engineer F	83	-10%	-17%	-15%	-19%
Non-Represented	Area Superintendent	16	-6%	-3%	0%	-2%
Non-Represented	Human Resource Manager / Consultant	8	-30%	-29%	-26%	-29%
Non-Represented	Field Service Coordinator*	76	11%	10%	14%	6%
Non-Represented	Administrative Assistant	8	-3%	-4%	-3%	-4%
	2013 Weighted Average Non-Represented	206	-2%	-4%	-1%	-6%
	2011 Weighted Average Non-Represented	137	-17%	-20%	-17%	-18%
	2008 Weighted Average Non-Represented	151	-2%	-4%	-1%	-5%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*
[5] *Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs. The results do not reflect a 0.75% employee pension contribution increase effective October 1st, 2013.*

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation (Current) results have increased from 5% above market median to 9% above market median.

Table 6

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market P50[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Professionals	Engineer E	132	-2%	-6%	-3%	-6%
	Business Analyst C	15	26%	21%	38%	32%
	Engineer D	258	4%	-1%	7%	5%
	Engineer C	18	14%	3%	19%	14%
	Engineer B	271	10%	9%	12%	12%
	Business Analyst A	11	25%	23%	30%	30%
	Engineer A	41	18%	11%	12%	12%
	2013 Weighted Average Professionals	746	7%	3%	9%	7%
	2011 Weighted Average Professionals	779	6%	-3%	5%	4%
	2008 Weighted Average Professionals	578	8%	-2%	5%	3%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)

[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.

[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.

[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.

[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2011, the 2013 Total Compensation results have improved from 18% above market median to 12% above market median.

Table 7

			Hydro One P50 Relative to Market P50[1]		
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
Power Workers	System Operator (Controller)	92	25%	16%	28%
Power Workers	Regional Maintainer - Lines (Supervisory)	92	18%	16%	24%
Power Workers	Protection and Control Technician	82	20%	18%	30%
Power Workers	Area Distribution Engineering Technician	180	12%	12%	23%
Power Workers	Regional Maintainer - Lines	742	7%	7%	22%
Power Workers	Regional Maintainer - Electrical	238	2%	2%	17%
Power Workers	Fleet Mechanic	68	8%	7%	21%
Power Workers	Lineman - Journeyman	80	14%	14%	4%
Power Workers	Regional Maintainer - Forestry	n/a	-	-	-
Power Workers	Service Dispatcher	20	33%	29%	41%
Power Workers	Drafter II	33	18%	18%	30%
Power Workers	Stock Keeper	49	21%	21%	37%
Power Workers	Data Entry Clerk	63	11%	9%	21%
Power Workers	Production Field Administrator III	3	-36%	-36%	-31%
Power Workers	Electrical Apprentice	63	-17%	-21%	-24%
Power Workers	Lines Apprentice	285	-4%	-8%	-13%
Power Workers	Meter Reader	10	-2%	-6%	-7%
Power Workers	General Labourer/Roustabout	10	-13%	-16%	-27%
	2013 Weighted Average Power Workers	2,100	8%	6%	12%
	2011 Weighted Average Power Workers	2,411	10%	9%	18%
	2008 Weighted Average Power Workers	1,966	20%	10%	21%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*

APPENDIX A

Hydro One vs. Market Average

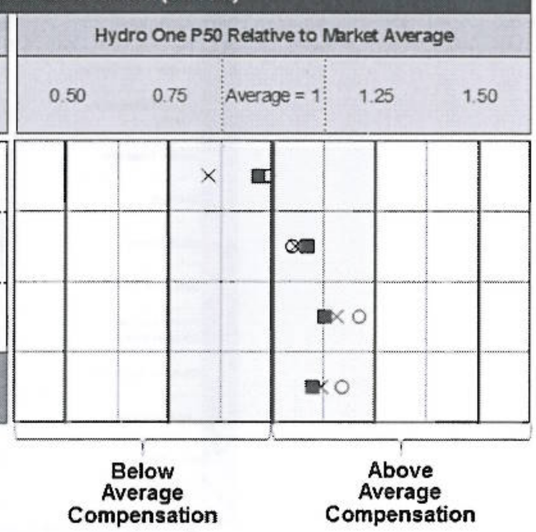
As requested by stakeholders, summarized below are the results of our compensation benchmarking analysis comparing Hydro One median to market average.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 10% above the market average (mean).** Hydro One's position relative to market varies by employee group from a low of 3% below the market average for the non-represented group to a high of 13% above the market average for the PWU.

Table 8

Legend
- ■ 2013 Hydro One Position Relative to Market
- X 2011 Hydro One Position Relative to Market
- O 2008 Hydro One Position Relative to Market

			Total Remuneration (Current)		
			Multiple of Average		
	Hydro One Group	# of Hydro One Incumbents	2013	2011	2008
Weighted Average	Non-Represented	206	0.97	0.84	0.99
	Professionals	746	1.09	1.06	1.05
	Power Workers	2,100	1.13	1.15	1.21
	Overall	*3,052*	*1.10*	*1.12*	*1.17*



Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

Table 9

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market Average[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Non-Represented	Financial Director	3	-1%	6%	7%	7%
Non-Represented	Top Rates and Regulatory Affairs Executive	4	-14%	-15%	-17%	-18%
Non-Represented	Senior Legal Counsel	8	-6%	-4%	3%	-2%
Non-Represented	Engineer F	83	-13%	-18%	-15%	-20%
Non-Represented	Area Superintendent	16	-7%	-8%	-8%	-9%
Non-Represented	Human Resource Manager / Consultant	8	-32%	-34%	-32%	-35%
Non-Represented	Field Service Coordinator*	76	11%	10%	14%	6%
Non-Represented	Administrative Assistant	8	-7%	-8%	-8%	-8%
	2013 Weighted Average Non-Represented	206	-4%	-6%	-3%	-8%
	2011 Weighted Average Non-Represented	137	-15%	-17%	-16%	-17%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)*

[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*

[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*

[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*

[5] *Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.*

The results do not reflect a 0.75% employee pension contribution increase effective October 1st, 2013.

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

Table 10

	Hydro One Group	# of Hydro One Incumbents	Hydro One P50 Relative to Market Average[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
					Current[4]	Future[5]
Professionals	Engineer E	132	0%	-8%	-1%	-5%
Professionals	Business Analyst C	15	23%	18%	31%	26%
Professionals	Engineer D	258	6%	-2%	4%	3%
Professionals	Engineer C	18	13%	7%	19%	14%
Professionals	Engineer B	271	12%	5%	14%	14%
Professionals	Business Analyst A	11	16%	13%	19%	19%
Professionals	Engineer A	41	12%	6%	15%	15%
	2013 Weighted Average Professionals	746	8%	1%	9%	7%
	2011 Weighted Average Professionals	779	6%	-1%	6%	4%

[1] Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.)
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents in the new pension and benefits programs.

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

Table 11

			Hydro One P50 Relative to Market Average[1]		
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
Power Workers	System Operator (Controller)	92	17%	13%	25%
	Regional Maintainer - Lines (Supervisory)	92	14%	13%	25%
	Protection and Control Technician	82	20%	18%	28%
	Area Distribution Engineering Technician	180	11%	9%	21%
	Regional Maintainer - Lines	742	8%	6%	19%
	Regional Maintainer - Electrical	238	7%	7%	21%
	Fleet Mechanic	68	12%	10%	19%
	Lineman - Journeyman	80	13%	10%	5%
	Service Dispatcher	20	29%	26%	41%
	Drafter II	33	9%	6%	15%
	Stock Keeper	49	21%	19%	31%
	Data Entry Clerk	63	6%	5%	16%
	Production Field Administrator III	3	-37%	-37%	-32%
	Electrical Apprentice	53	-19%	-22%	-28%
	Lines Apprentice	285	3%	1%	-7%
	Meter Reader	10	0%	-3%	-6%
	General Labourer/Roustabout	10	-13%	-14%	-27%
	2013 Weighted Average Power Workers	2,100	9%	7%	13%
	2011 Weighted Average Power Workers	2,411	10%	8%	15%

[1] *Market results weighted by organization (i.e., for each participating organization, Mercer determined one average value per position.*
[2] *Base salary plus short-term incentives granted (i.e., bonus), where applicable.*
[3] *Total cash compensation plus estimated long-term incentives, benefits and pension values.*
[4] *Based on Hydro One's employee population, assuming current pension and benefits program eligibility.*

APPENDIX B

Position Descriptions

Benchmark Position	Survey Code	Generic Description
Administrative Assistant	220.108.430	Requires a general knowledge of departmental procedures, practices and office routine. Possesses good office and computer skills including word processing, spreadsheets, graphics software, dictaphone transcription, and filing. May provide assistance to a more senior Administrative Assistant in a large department.
Area Distribution Engineering Technician	999.999.001	Perform Technical support work for the Distribution Section of the area: such as monitoring the performance of the distribution system by performing various technical studies, identifying and recommending solutions to the supervisor, providing field data and preliminary analysis for engineering studies. Negotiate property settlements on distribution lines and perform joint use activities. Provide administrative support related to preparation of estimates and work orders (WO) work schedules, line layouts, joint use, provision of underground cable and fault location service. Perform staking activities and prepare design packages for new connections, service upgrades, extensions, betterments and relocations.
Area Superintendent	700.792.211	Responsible for providing construction management and supervision within the construction group. Administers construction contracts. Is accountable for construction costs, schedules, safety, product quality and environment performance. Provides input into Project Execution Plans and the associated schedules and estimates. Usual qualifications include 10 to 12 years of experience including supervisory experience. Requires experience in construction management and supervision of various trades.
Business Analyst A	320.392.360	Assists with analyzing internal metrics. Performs responsible and varied business analytical or administrative functions. Assists with preparation documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree.
Business Analyst C	320.392.340	Analyzes internal metrics. Performs responsible and varied business analytical or administrative functions. Prepares documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree with a minimum of 4 years' related experience; technical diploma with a minimum of 6 years' related experience.
Data Entry Clerk	999.999.002	Perform data processing services including inputting, updating, to various computerized databases and applications of external service providers. Perform clerical/administrative duties in support of system processes. Work with various internal and external contacts and customers in the setup, maintenance, reporting and follow up of non-electricity accounts, customer service orders, materials, corporate charge cards, time reporting, management reporting, damage claims, accounts receivable, etc. Perform administrative services for provincial client group and special projects.
Drafter II	510.656.420	Incumbent works on standard drafting assignments. Methods are detailed and standard but judgment is required in planning tasks and choice of methods. Accountable for accuracy and adequacy of work performed. May provide technical guidance to less experienced Drafters. Usual qualifications include a technical school diploma or equivalent, with a minimum of 5 years' related experience.
Electrical Apprentice	999.999.112	A five year apprenticeship leading to a Construction and Maintenance Electrician

Benchmark Position	Survey Code	Generic Description
Engineer A	510.780.360	Incumbent receives "on-the-job" training in various phases of office, plant or field engineering through assignments or, in some cases, classroom instruction. Tasks assigned are simple and routine in nature. Assists more senior engineers in the preparation of plans, calculations, reports, etc. Few technical decisions are made and these are routine, with clearly defined procedures and guidelines. Works under close supervision and work is reviewed for accuracy, adequacy and conformance with prescribed procedures. Usual qualifications include a university degree in engineering with minimal experience.
Engineer B	510.780.350	Uses a variety of standard problem solving techniques. May assist more senior engineers in carrying out technical tasks requiring computation methods. Duties are assigned with detailed oral and occasionally written instructions. Work is reviewed in detail with guidance given. May give limited technical guidance to junior professionals or technicians working on a common project. Usual qualifications include a university degree in engineering with a minimum of 2 years' related experience.
Engineer C	510.780.340	Incumbent is responsible for varied engineering assignments requiring a broad knowledge of an engineering specialty and the effect the work has upon other fields. Solves problems using a combination of standard or modified procedures. Participates in planning objectives. Performs independent studies, and analyzes, interprets and draws own conclusions; more complex work projects are referred to more senior authorities. Not supervised in detail except on more difficult assignments. May give periodic technical guidance to less experienced professionals or technicians assigned to work on a common project. Usual qualifications include a university degree in engineering with a minimum of 4 years' related experience.
Engineer D	510.780.330	This is the first level of full engineering specialization and is considered the senior level position. Alternatively may be the level at which an individual acts as group leader or work task force leader of a small group of technical personnel. Requires application of well-developed technical knowledge in planning, conducting and coordinating difficult assignments. The position requires the modification of established guidelines and initiation of new approaches. Makes independent decisions in planning, organizing and completing technical assignments. Work is reviewed for soundness of judgment but accepted technically as accurate and feasible. Work is assigned in terms of objectives and priorities but informed guidance is available. Advises on technical problems and supervision, and may plan, schedule and review work of professional engineers and technicians. May make recommendations concerning selection, training, discipline and remuneration of staff.
Engineer E	510.780.320	May have responsibility for coordinating engineering work assignments and making recommendations on technical applications developed by other professional personnel or consultants. May involve the direct supervision of a group of professionals. Provides guidance and training to less experienced staff. Checks work for accuracy and completeness. As a specialist, conducts special, complex and advanced level studies. Work is generally reviewed for results only. Makes independent decisions within broad guidelines and policies. May make recommendations concerning selection, training, discipline and remuneration of staff. May also responsible for construction.
Engineer F	510.780.310	Incumbent is considered an authority in an engineering field of specialization and acts as a technical consultant to the organization. This level is a dual-stream first level managerial position. Incumbents may be responsible for directing a staff of professional and support employees or act as a technical specialist. Responsible for planning and directing large engineering programs/projects; sets priorities and allocates resources; makes necessary decisions on all day-to-day operating matters within constraints of company policy. Receives work in terms of broad objectives.
Field Service Coordinator	700.793.240	Manage and supervise trade, technical and clerical staff. Develop work programs, organize schedules, provide instructions, guidance and checks, monitor work to ensure work quality and accuracy and in conformity to governing regulations. Ensure the administration of procedures, applicable legislation and collective agreements are met. Administer and control contract work. Review work methods, ensure appropriate training. Develops, maintains and enhance customer relationships through direct contact both internally and externally. This position is non-represented.
Financial Director	210.100.130	Responsible for providing overall direction for tax, insurance, budget, credit and treasury functions for the organization. Provide short to medium term direction for all corporate financial functions so that financial transactions, policies, and procedures meet the organization's short and medium-term business objectives and are conducted in accordance with regulations, and standards. Activities may include: credit control; cash flow; investment management; tax; insurance; treasury; internal audit; budgeting and forecasting; and foreign exchange. Lead, direct, evaluate, and develop a team of senior managers to ensure that the organization's financial strategy is implemented effectively, consistently and according to established guidelines.

Benchmark Position	Survey Code	Generic Description
Fleet Mechanic	999.999.011	Be responsible for the inspection, repair and maintenance, as well emergency repair of vehicles (e.g. bucket truck, all-terrain vehicles, go track, digger truck, ladder truck forklift, backhoe, manlift, vans/pickup trucks and the hydraulic equipment of the vehicles e.g. booms, buckets. Maintain inspection schedules and coordinate scheduling repairs to be contracted out. Work is performed in a garage or on site.
General Labourer/Roustabout	700.792.431	This is the level at which individuals with no previous experience enter into the company. Acts as a general labourer. Works under close supervision within well-defined procedures. Duties involve general field/plant maintenance or clean-up work. Minimum qualifications include a high school diploma with minimal related experience.
Human Resource Manager / Consultant	120.100.220	This position plans, designs, develops, implements and administers policies and programs through functional supervision in all or some of the following areas: employee relations, executive compensation, wage and salary administration, job evaluation, performance management, recruitment and selection and employment equity/ human rights.
Lineman - Journeyman	920.788.410	Responsible for the installation, maintenance, removal, and inspection of transmission/distribution power lines. Typically requires 4 years of experience and certification as a Power Line Technician (or equivalent).
Lines Apprentice	999.999.113	A four year apprenticeship leading to a Power Line Technician position.
Meter Reader	920.680.430	Responsible for reading electric, gas, or water meters and keeping track of their average use by recording information. Other duties would include inspecting meters for damages and defects. Entry level position which typically requires a high school education.
Production Field Administrator III	220.778.413	Works independently. Works closely with field operations. Assists in all areas of production and general accounting duties, clerical and office administration functions. Provides analysis and input of operational accounting information and codes and inputs all payables and production volumes. May assist in preparing special production reports. Requires broad knowledge of department procedures. Orders all stationery/supplies and runs office. Monitors, troubleshoots and co-ordinates with head office maintenance of existing computer systems. May check work of junior staff and provide guidance. Working with a Supervisor, assists in preparing field accruals and analyzes actual performance versus budget. Possesses a solid understanding of basic accounting principles. Requires advanced PC and database management knowledge. An accounting background or diploma with 8 years' office experience is typically required.
Protection and Control Technician	999.999.004	Perform initial inspections, conduct trouble-shooting and preventative maintenance, carry out modifications and repairs as required, on all types of protection, telecommunications, metering and control equipment which comes under Protection and Control (P&C) jurisdiction. Discuss and review results with supervisor, if the equipment is highly critical from the standpoint of system operation, before putting the equipment into service.
Regional Maintainer - Electrical	999.999.007	Responsible for the general maintenance and repair work on electrical systems and equipment at various geographical locations. Requires overhauling, maintaining and inspecting equipment such as conductors & insulators i.e. batteries, station bus, cable, compressed air systems, fire protection equipment switchgear i.e. circuit breakers, load interrupters metalclad switchgear, oil circuit breakers, SF6 breakers, air blast breakers, transformers, rotating machines, distribution stations & equipment. Has the necessary knowledge of the trade theory, operating principles, charts, tables, testing equipment and other reference works, to test, dismantle, repair, clean and assemble station electrical equipment within the required specifications. Requires certification as a construction and maintenance electrician. Also performs mechanical and protection and control work.

Benchmark Position	Survey Code	Generic Description
Regional Maintainer - Forestry	999.999.005	Perform line clearing adjacent to power lines and associated apparatus. Carries out all phases of vegetation management including the application of pesticides. Understands and operates tools associated with the trade, various types of vehicles and aerial equipment, hand or power-operated pesticide application equipment. Must provide at own expense, any tools listed for this classification if required in his/her work, in accordance with the attached tool list. In addition to the above, may have the following skills: • Lead Hand Skills (including documentation, job planning and knowledge of work management systems as required) • Work Protection Code Skills (including establishing, and holding) • Contract Monitoring Skills • Environment Skills (such as PCB management, WHMIS, waste management, etc.)
Regional Maintainer - Lines	999.999.006	Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Understands and is able to operate the tools of his/her trade, and is familiar with the various instruments, i.e. voltmeters, ammeters and ohmmeters. Must be familiar with hydraulically-operated articulated or telescopic aerial devices. Must provide at own expense any tools listed for the classification if required in his/her work in accordance with the attached tool list. This classification also includes the requirement to hold a Power Line Technician certification (or equivalent).
Regional Maintainer - Lines (Supervisory)	999.999.008	This position is responsible for the safety, quality and quantity of the work performed by his/her crew. They plan work including staffing requirements, assigning work, co-ordinate work with other work groups, ensure proper work practices are followed, report on work performed and engage in good public relations. He/she performs the following physical work activities. Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Also responsible for contract monitoring and lead hand responsibilities.
Senior Legal Counsel	115.100.340	Responsible for providing management and employees with advice on a broad range of moderately complex conflicting legal principles. The applicable laws and regulations are numerous and varied, and present difficult problems of interpretation. Applies independent judgment in recommending a course of action for a client department, providing input as to the ramifications of a course of action, a legal decision, or a new piece of legislation. Usual qualifications include a law degree, membership in a law society/bar association and/or other relevant jurisdiction with a minimum of 8 year's related experience.
Service Dispatcher	430.612.340	Responsible for handling incoming consumer calls to schedule and dispatch service technicians to problem areas (including high voltage switching). Maintains documentation of crew activities for continuous knowledge of line and substation work. Key coordinator during power failures provides notification to internal and external customers regarding restoration of power services.
Stock Keeper	999.999.009	Receives, receipts, stores, issues and ships materiel used in operations. Manages materiel, in accordance with established practices and regulations. Is responsible for materiel under his/her control. Performs maintenance, not requiring formal trades qualifications, and assists in tasks where unskilled or semi-skilled ability is required.
System Operator (Controller)	999.999.010	Monitor and operate the transmission/distribution system assets on a 24-hour basis. Determine condition and recommend on availability of equipment. Carry out Manual Block and Rotational Load Shedding Schedules procedures. Monitor, approve and report LV - load transfers. Direct / monitor personnel on a 24 hour basis (i.e. - switching agents, field crews) in the operation of the Transmission / Distribution network system assets. Troubleshoot & sectionalize for low voltage feeder faults.
Top Rates and Regulatory Affairs Executive	110.200.130	Executive with primary responsibility for preparing, managing, and leading company's testimony in utilities rate cases before local, regional or federal agencies. Responsibilities include development of all research associated with regulatory activities including activity across other regulatory entities and maintaining relationship with all regulators. Develops cost factors in association with utilities rate cases, may or may not, be involved in delivery of testimony. Typically reports to a Top Legal Executive, Chief Operations Officer or a Top Utilities Executive.

APPENDIX C

Detailed Compensation Benchmarking Methodology

Summarized in this appendix is supporting descriptions of how we determined values for each of the major components of compensation. Specifically:

Base Salary – Annual base salary at July 1, 2013. If an hourly rate was reported, we annualized the value by multiplying the standard number of hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans. See detailed methodology below.

Total Compensation - Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

Detailed Benefits and Pension Methodology – Total remuneration includes the following values for benefits and pensions:

- Mercer's relative value process applies a broad set of standard cost factors, plus actuarial and demographic assumptions to measure all of the financially significant features of benefit programs on a benefit line basis.
- Effectively, this process isolates the plan design and removes variable factors such as historical experience, demographics, and utilization trends specific to each participant in the study. For example, if two survey participants have an identical benefit offering, the values will be equal regardless of the actual plan costs to each of the employers.

Aligning Values with Hydro One's Actual Costs

- For the purpose of this Total Compensation Cost Study, we adjusted the manual rates within our relative value tools so that the results by line of benefit more closely reflect Hydro One's actual benefit costs and liability figures.

Participation & Anti-Selection:

Active Flex Benefits:

- Participation: We use a standardized set of participation assumptions for all participants that vary only by the number of options that are offered under the plan. Therefore, two identical flex programs will produce similar relative Total Values.

- Anti-Selection: A unique feature of flex plans is that employees who choose richer options are likely to be higher claimers than those choosing poorer options. This is reflected within our methodology by increasing the value of the richer options and reducing the value of the poorer options. The final relative values of the flex plan are a weighted average of the values of each of the options.

- Optional plans that are fully employee-paid (such as optional life) are excluded from the review.

- Low value core plans / catastrophic core plans and spousal top-up plans are excluded from the valuation.

Projection Methodology for Pension Plans

Defined Benefit Plans

- For defined benefit plans, annual service costs were estimated for each company's plan design at various earnings levels using a common sample employee demographic (age and years of service). The annual service costs were converted into company provided values by deducting any required employee contributions under each plan. The resulting company provided values were expressed as a percentage of earnings to be applied to the earnings associated with each benchmark position.

Defined Contribution Plans

- For defined contribution benefit plans, the company provided value was set equal to the company contributions.

- Where employees are entitled to choose the level of their contributions, employees were assumed to contribute at the level that would maximize company contributions.

Projection Methodology for Post Retirement Non-Pension (PRNP)

Employee-specific factors including earnings and service are projected to each of the assumed retirement ages at which point the benefit payable is determined, actuarially valued and discounted with interest to the current age of the employee. The resulting values are split pro-rata on service into the benefit in respect of past service and the benefit in respect of future service, and the future service benefit value is converted to a level percentage of future pensionable earnings.

- The results are weighted by the assumed retirement rates and combined to produce a single value of future benefit accruals, as a percentage of future earnings, per member.
- Benefits are projected both before and after retirement based on benefit-specific (e.g. medical, dental) inflation assumptions.
- Benefits are coordinated with provincial medical and drug plans.
- Lifetime maximums are reflected where applicable.

Flex Premium Cost Sharing & Credit Allocation:

- Cost sharing is determined using each participant's actual price tag and credit formula.
- Assumptions are made as to where credits would commonly be used, unless they are allocated to specific benefits. These assumptions coordinate with the standardized participation assumptions outlined earlier.

Standard Demographic Assumptions:

- A common population reflecting the general demographics of a Canadian workforce group and adjusted to more closely mirror Hydro One's workforce is used in the analysis.
  - This population reflects a group of employees with an average age of 45, average service of 15 years, and average annual earnings of $110,000 (average earnings used for benefit purposes).
- For Pension and Post Retirement Non-Pension benefits, the above population is assumed to retiree approximately as follows:
  - 25% of the group retire at age 55
  - 60% of the group retire at age 60
  - 15% of the group retire at age 65
  - 70% of the active members are assumed to be married over their career while 90% of members are assumed to be married at the time of their retirement

Other Actuarial Assumptions:

- The following assumptions were used in the review:
  - Discount rate: 4.25% per annum
  - Inflation: 2.00% per annum
  - Salary Increase: 4.00% per annum
  - Post Retirement mortality UP 1994 generational mortality (80% male)
  - Termination rates of 2% each year prior to age 55 (for pension values)
  - Medical and Dental inflation/utilization increases

MERCER

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2010

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,397	327,600,666	260,915,303	51,809,932	6,528	14,868,904	76,808
SOCIETY Reg	1,315	125,599,454	117,961,991	4,326,114	22,859	3,288,489	89,705
MCP Reg	651	88,150,303	74,337,104	403,461	8,568,152	4,841,586	114,189
Total Reg	**5,363**	**541,350,422**	**453,214,398**	**56,539,507**	**8,597,538**	**22,998,979**	**84,508**
PWU Temp	185	5,762,822	5,627,702	62,451		72,670	30,420
Society Temp	80	5,097,027	4,793,945	112,596		190,486	59,924
MCP Temp	21	1,366,870	1,315,636			51,234	62,649
Total Temp	**286**	**12,226,719**	**11,737,283**	**175,047**		**314,389**	**41,039**
CASUAL	1707	109,976,920	84,735,113	12,740,012		12,501,795	49,640
Total	**7356**	**663,554,061**	**549,686,793**	**69,454,566**	**8,597,538**	**35,815,164**	**74,726**

2011

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,456	353,770,142	275,254,552	63,197,265		15,318,324	79,645
SOCIETY Reg	1,330	134,279,772	126,051,768	4,947,039	2,250	3,278,715	94,776
MCP Reg	644	88,234,049	73,880,625	69,859	9,414,079	4,869,486	114,721
Total Reg	**5,430**	**576,283,963**	**475,186,946**	**68,214,163**	**9,416,329**	**23,466,525**	**87,511**
PWU Temp	211	5,508,958	5,331,454	85,668		91,836	25,268
Society Temp	79	5,234,552	4,983,808	26,116		224,627	63,086
MCP Temp	22	1,660,391	1,612,601	1,331		46,460	73,300
Total Temp	**312**	**12,403,901**	**11,927,862**	**113,115**		**362,923**	**38,230**
CASUAL	1488	106,663,199	80,054,576	14,588,897		12,019,727	53,800
TOTAL	**7,230**	**695,351,063**	**567,169,384**	**82,916,175**	**9,416,329**	**35,849,175**	**78,447**

2012

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,475	357,280,035	284,842,527	56,320,273	3,000	16,114,235	81,969
SOCIETY Reg	1,336	139,483,054	131,185,379	4,758,285	54,686	3,484,704	98,193
MCP Reg	643	88,165,625	73,683,706	126,637	9,884,915	4,470,367	114,594
Total Reg	**5,454**	**584,928,714**	**489,711,612**	**61,205,195**	**9,942,601**	**24,069,306**	**89,789**
PWU Temp	214	5,476,528	5,366,490	78,090	0	31,949	25,077
Society Temp	61	3,758,898	3,549,772	28,883	0	180,243	58,193
MCP Temp	18	1,061,210	1,018,662	0	0	42,548	56,592
Total Temp	**293**	**10,296,636**	**9,934,925**	**106,973**		**254,739**	**33,908**
CASUAL	1493	104,268,709	81,843,677	10,569,037		11,855,994	54,818
TOTAL	**7,240**	**699,494,059**	**581,490,214**	**71,881,205**	**9,942,601**	**36,180,039**	**80,316**

2013

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,488	365,509,485	291,626,287	57,446,678		16,436,519	83,608
SOCIETY Reg	1,341	142,717,718	134,309,870	4,853,450		3,554,398	100,157
MCP Reg	653	92,334,945	76,326,235		11,448,935	4,559,775	116,886
Total Reg	**5,482**	**600,562,148**	**502,262,392**	**62,300,129**	**11,448,935**	**24,550,692**	**91,620**
PWU Temp	349	9,039,170	8,926,931	79,652		32,587	25,579
Society Temp	69	4,308,931	4,095,622	29,461		183,848	59,357
MCP Temp	22	1,313,331	1,269,932			43,398	57,724
Total Temp	**440**	**14,661,431**	**14,292,485**	**109,112**		**259,834**	**32,483**
CASUAL	2283	162,629,854	127,653,113	16,484,725		18,492,016	55,915
TOTAL	**8,205**	**777,853,433**	**644,207,990**	**78,893,966**	**11,448,935**	**43,302,541**	**78,514**

2014

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,467	371,028,782	295,667,920	58,595,612		16,765,250	85,281
SOCIETY Reg	1,311	142,507,283	133,931,278	4,950,519		3,625,486	102,160
MCP Reg	622	89,931,336	74,156,840		11,123,526	4,650,970	119,223
Total Reg	**5,400**	**603,467,401**	**503,756,038**	**63,546,131**	**11,123,526**	**25,041,706**	**93,288**
PWU Temp	381	10,084,889	9,940,355	111,294		33,239	26,090
Society Temp	103	6,453,605	6,236,030	30,050		187,525	60,544
MCP Temp	56	3,341,472	3,297,205			44,266	58,879
Total Temp	**540**	**19,879,965**	**19,473,591**	**141,344**		**265,030**	**36,062**
CASUAL	2283	165,882,451	130,206,175	16,814,419		18,861,856	57,033
TOTAL	**8,223**	**789,229,817**	**653,435,804**	**80,501,895**	**11,123,526**	**44,168,592**	**79,464**

2015

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,435	375,665,798	298,797,719	59,767,524		17,100,555	86,986
SOCIETY Reg	1,281	142,231,344	133,483,819	5,049,530		3,697,995	104,203
MCP Reg	592	87,217,155	71,991,746		10,798,762	4,426,647	121,608
Total Reg	**5,308**	**605,114,297**	**504,273,284**	**64,817,054**	**10,798,762**	**25,225,197**	**95,003**
PWU Temp	410	11,069,555	10,910,909	122,161		36,485	26,612
Society Temp	132	8,436,052	8,151,642	39,281		245,129	61,755
MCP Temp	85	5,173,314	5,104,780			68,534	60,056
Total Temp	**627**	**24,678,921**	**24,167,332**	**161,442**		**350,148**	**38,544**
CASUAL	2283	169,200,100	132,810,299	17,150,708		19,239,093	58,174
TOTAL	**8,218**	**798,993,318**	**661,250,915**	**82,129,203**	**10,798,762**	**44,814,438**	**80,464**

2016

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,414	381,209,233	302,910,428	60,962,875		17,335,930	88,726
SOCIETY Reg	1,252	141,908,260	133,071,176	5,150,520		3,686,564	106,287
MCP Reg	574	86,256,588	71,198,864		10,679,830	4,377,894	124,040
Total Reg	**5,240**	**609,374,080**	**507,180,468**	**66,113,395**	**10,679,830**	**25,400,388**	**96,790**
PWU Temp	437	12,026,290	11,862,021	124,604		39,665	27,144
Society Temp	148	9,642,919	9,322,514	40,066		280,339	62,990
MCP Temp	94	5,835,499	5,758,192			77,306	61,257
Total Temp	**679**	**27,504,708**	**26,942,728**	**164,670**		**397,310**	**39,680**
CASUAL	2283	172,584,102	135,466,505	17,493,722		19,623,875	59,337
TOTAL	**8,202**	**809,462,891**	**669,589,701**	**83,771,787**	**10,679,830**	**45,421,573**	**81,637**

2017

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,392	386,728,459	306,977,626	62,182,132		17,568,701	90,500
SOCIETY Reg	1,224	141,626,776	132,697,046	5,253,531		3,676,199	108,413
MCP Reg	554	84,916,154	70,092,429		10,513,864	4,309,861	126,521
Total Reg	**5,170**	**613,271,389**	**509,767,101**	**67,435,663**	**10,513,864**	**25,554,761**	**98,601**
PWU Temp	461	12,933,528	12,763,752	127,096		42,680	27,687
Society Temp	161	10,696,142	10,344,211	40,868		311,063	64,250
MCP Temp	109	6,902,029	6,810,594			91,435	62,483
Total Temp	**731**	**30,531,699**	**29,918,557**	**167,964**		**445,178**	**40,928**
CASUAL	2283	176,035,784	138,175,835	17,843,596		20,016,353	60,524
TOTAL	**8,184**	**819,838,872**	**677,861,493**	**85,447,223**	**10,513,864**	**46,016,291**	**82,828**

2018

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,366	391,925,597	310,717,106	63,425,775		17,782,716	92,310
SOCIETY Reg	1,189	140,481,758	131,480,656	5,358,601		3,642,500	110,581
MCP Reg	534	83,487,601	68,913,257	-	10,336,988	4,237,356	129,051
Total Reg	**5,089**	**615,894,956**	**511,111,019**	**68,784,376**	**10,336,988**	**25,662,572**	**100,434**
PWU Temp	492	14,070,593	13,894,493	129,638		46,461	28,241
Society Temp	180	12,192,668	11,796,256	41,685		354,727	65,535
MCP Temp	125	8,073,474	7,966,520	0		106,954	63,732
Total Temp	**797**	**34,336,735**	**33,657,269**	**171,323**		**508,143**	**42,230**
CASUAL	2283	179,556,499	140,939,352	18,200,468		20,416,680	61,734
TOTAL	**8,169**	**829,788,190**	**685,707,640**	**87,156,168**	**10,336,988**	**46,587,394**	**83,940**

2019

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,336	389,225,267	314,106,747	64,694,290		10,424,230	94,157
SOCIETY Reg	1,156	139,466,124	130,388,117	5,465,773		3,612,233	112,792
MCP Reg	508	81,011,115	66,869,088	-	10,030,363	4,111,664	131,632
Total Reg	**5,000**	**609,702,506**	**511,363,952**	**70,160,064**	**10,030,363**	**18,148,126**	**102,273**
PWU Temp	524	15,276,868	15,094,164	132,231		50,473	28,806
Society Temp	204	14,089,055	13,636,472	42,519		410,065	66,845
MCP Temp	151	9,947,812	9,816,028	0		131,785	65,007
Total Temp	**879**	**39,313,735**	**38,546,664**	**174,750**		**592,322**	**43,853**
CASUAL	2283	183,147,629	143,758,139	18,564,478		20,825,013	62,969
TOTAL	**8,162**	**832,163,871**	**693,668,755**	**88,899,291**	**10,030,363**	**39,565,462**	**84,988**

ATTACHMENT 3
Expert Evidence Statement from Mercer (Canada) Limited

This Expert Evidence Statement is provided in response to the Ontario Energy Board, Rules of Practice and Procedure, Rule 13A regarding the use of an expert to provide evidence. This Statement is for the preparation of the Compensation Cost Benchmarking Study, dated December 2, 2013, prepared by Mercer (Canada) Limited.

Title of Report:
Compensation Cost Benchmarking Study

Consultant:
Iain Morris
Partner, Talent Business Leader – Central Canada
Mercer (Canada) Limited
161 Bay Street
Toronto, Ontario M5J 2S5

- Human Resource consultant to major Canadian and multi-national employers
- Extensive experience on total reward strategy, rewards program design, benchmarking and cost analyses

Qualifications:
Education: Bachelor of Arts Queen's University 1980

Experience: Mr. Morris consults to many of Canada's leading organizations with a focus on reward strategy design and implementation. This includes business needs driven rewards strategy development and the design and implementation of performance-linked compensation systems. Iain has worked with organizations in a number of industries including: mining, utilities, financial services, retail, and manufacturing. Recent projects include:

- Leading a comprehensive total reward benchmarking and cost analysis for a major gas distribution company

- Developing and implementing a total reward strategy for a major engineering consulting firm

- Assessing the effectiveness of the total reward strategy and program design for a leading retailer

Iain has more than 30 years of rewards consulting experience with Mercer and another global H.R. consulting firm.
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Instructions Provided:
The primary sources of instructions were the RFP, (RFP #7000003202, May 3rd 2013) that Hydro One issued for this project and various conversations with Hydro One in verifying scope and progress.

The following are excerpts from the RFP:
"in its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and the other expectations for further information on compensation and efficiency comparisons".

The Board directed "Hydro One to revisit compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America." Towards that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses".

Mercer met with Stakeholders and with Hydro One during the course of conducting the study to receive feedback on the project methodology and progress.

Basis of Evidence:
1) 2008 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
2) 2011 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
3) 2013 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
4) Total Compensation data and program design information for Hydro One provided by the Company Human Resources Department
5) Mercer and industry standard analytical methods and assumptions

Context of Evidence:
NA

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert: Iain Morris

Date: 14 January 2014

PENSION COSTS

1.0 PENSION COSTS

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

The Plan covers Hydro One and its subsidiaries, except Hydro One Brampton Inc. The Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for Hydro One Networks, the Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Hydro One Network's financial statements.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP-2005-0020/EB-2005-0378). Pension costs were similarly approved for Transmission pension costs (EB-2006-0501, EB-2008-0272, and EB-2010-0002); this treatment was continued in Hydro One Distribution's last cost of service application as well (EB-2009-0096).

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost and the Inergi annual pension charge is consistent among all common corporate costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378, EB-2006-0501, EB-2007-0681 and EB-2008-0272, EB-2009-0096, EB-2010-0002 and EB-2012-0031.

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

Annual cash pension cost (millions)

(*may not add due to rounding*)

2015

Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	29	41	4	74
Capital	$M	42	45		87
	$M	**71**	**86**	**4**	**161**

2016

Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	29	45	4	78
Capital	$M	40	44		84
	$M	**69**	**89**	**4**	**162**

2017

Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**

OM&A	$M	29	45	4	79
Capital	$M	40	44		83
	$M	**69**	**89**	**4**	**162**

2018

Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	31	44	4	79
Capital	$M	39	45		84
	$M	**70**	**89**	**4**	**163**

2019

Corporate Pension Costs		**Transmission**	**Distribution**	**Other**	**Total**
OM&A	$M	31	44	4	78
Capital	$M	39	46		84
	$M	**70**	**89**	**4**	**163**

2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Plan was as at December 31, 2011. In May 2012, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO). The valuation showed that the Plan had a deficit of $498 million, on a going-concern basis. The required contribution for the Hydro One companies was initially set at $159 million starting in 2012, variable based on the level of base pensionable earnings. Of this amount, about $99 million represented annual current service costs, and the remaining portion represented special payments over 15 years required toward the going-concern deficiency.

In accordance with applicable regulations, Hydro One makes all required contributions on a monthly basis.

Hydro One's next actuarial valuation is required by December 31, 2014. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

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

During 2011 and 2012, actual contributions were $153 million and $161 million, respectively. Actual contribution requirements in 2013 and 2014 may differ depending on the level of base pension earnings used to compute the monthly contribution. As well, actual contribution requirements in 2014 may materially differ from the estimates provided depending on the timing of the next actuarial funding valuation. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 1, Schedule 1).

3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2012, the Plan had a reported net asset value of $5,004 million and about 13,019 members. About 43% of the Plan's members are active. The remaining Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension or members on long-term disability. The Plan governance was reviewed during RP-2005-0020/EB-2005-0378.

The Fund has consistently outperformed the benchmark made up of passive market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2012, the Fund returned 5.63% annualized while the Fund's target benchmark is 5.47%, thus outperforming its target benchmark return by 0.16%. The fund's investments are divided into asset classes and each asset class has a corresponding market index (i.e. Canadian Equities market index is the S&P/TSX). The actual performance of each asset class is then measured against this market index (policy benchmark). The Fund's policy benchmark is a calculated weighted average benchmark based on the Fund's strategic asset mix.

COSTING OF WORK

1.0 OVERVIEW

Hydro One Distribution’s work program is bundled into packages of work identified as programs or projects. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. This Exhibit details the breakdown of each of these three cost activities, and how the costs are applied to programs and projects. This costing approach is consistent with the requirements of US Generally Accepted Accounting Principles (“USGAAP”).

Hydro One Distribution categorizes its costs into two major classifications - common and direct. Common costs, both OM&A and capital expenditures, are allocated to Distribution and Hydro One’s other lines of business. Direct costs charged to work orders include labour (comprising of salaries, benefits and pension costs), material, fleet and supply chain. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the work program or project. Fleet costs are charged using a fleet rate. Supply Chain costs are charged via a material surcharge. All of these elements are described in detail in this Exhibit.

2.0 PROJECT AND PROGRAM MAJOR COST CATEGORIES

2.1 Labour Rate

Labour hours are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are “fully loaded” to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components: forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. Table 1, below, shows an example of the composition of a standard labour rate for one category, the Regional Line Maintainer – Regular Staff,, over the period 2010 to 2019.

Table 1
Standard Hourly Labour Rate Composition
Regional Line Maintainer – Regular Staff

	Historic				Bridge	Test				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Payroll Obligations	69.09	70.60	74.42	75.76	76.85	77.50	78.15	78.80	79.45	80.10
Contractual time away from work	9.76	9.61	9.81	10.00	10.20	10.29	10.38	10.46	10.55	10.63
Time not directly benefiting a specific Program or Project	6.47	5.84	5.95	6.07	6.19	6.25	6.30	6.35	6.40	6.46
Field Supervision and Technical Support	10.17	8.41	9.94	10.98	10.27	10.36	10.44	10.53	10.62	10.71
Support Activities	14.51	15.53	14.88	15.18	14.49	14.61	14.74	14.86	14.98	15.10
Hourly Rate	**110.00**	**110.00**	**115.00**	**118.00**	**118.00**	**119.00**	**120.00**	**121.00**	**122.00**	**123.00**

The cost elements embedded in the standard rate as illustrated in Table 1 are explained in the pages following, using the position of Regional Line Maintainer – Regular Staff and the 2014 cost composition, as an example.

2.1.1 Payroll Obligations ($76.85)

A brief description of the cost elements included in this category is provided below. Compensation, wages and benefits are more fully explained in Exhibit C1, Tab 3, Schedule 2.

Base Labour and Payroll Allowances (58% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in wage schedules.
- Payroll Allowances: Allowances are also contractually negotiated and stated in collective agreements. Regular staff (PWU) is entitled to travel, footwear and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

Company Benefits (37% of Payroll Obligations)

- Regular Staff: Comprising pension (30.9% of base pensionable earnings) and current and post-employment benefits; health, dental, etc. (24.2% of base pensionable earnings).
- Non-Regular Staff (for example, casual trades): Pension and welfare contributions made on behalf of the non-regular employee. These contributions are significantly lower in comparison to the Company benefit contributions made on behalf of the regular employee.

Government Obligations (5% of Payroll Obligations)

- Consists of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB) contributions.

2.1.2 Contractual Time Away from Work ($10.20)

This category consists primarily of employee vacation and statutory holidays, all established and identified in the Company's collective agreements. Sickness and accident costs are also included and are based on historical trends and consider current Company initiatives.

2.1.3 Time Not Directly Benefiting a Specific Program or Project ($6.19)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

2.1.4 Field Supervision and Technical Support ($10.27)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

2.1.5 Support Activities ($14.49)

Administrative Expenses and Support (76% of Support Activities)

These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for clerical support activities and other centralized support to facilitate work management system requirements.

Work Methods & Training (14% of Support Activities)

Costs to design, develop, continually update and maintain and deliver work methods and training programs. Costs are assigned based on the forecast consumption of these services as agreed to by the Work Methods & Training function and service recipient.

Health, Safety & Environmental Support (10% of Support Activities)

Costs to design, develop, continually update and maintain and deliver health, safety and environmental practices primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the Health, Safety & Environment function and the service recipient.

2.2 Fleet Rate

Hydro One controls and manages approximately 7,300 vehicles and other fleet equipment to support its work programs and staffing requirements used for both Distribution and Transmission work. The fleet has grown by 1,600 vehicles and other fleet equipment since 2009 reflecting an increase in the work program to be executed. Fleet Management is described in Section 3.0 of this Exhibit.

Fleet assets are categorized into 59 classes of equipment. For each equipment class, a standard equipment rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours that the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program. Utilization hours are defined as the hours the equipment is being used “on the job”. Table 2 below displays the hourly fleet rate, as an example for one of the commonly used classes of equipment in the Distribution business (a line maintenance truck) for historical, bridge and test years, illustrating that the rate includes all costs attributable to the benefiting work.

Table 2
Hourly Fleet Rate - Line Maintenance Truck

	Historic				Bridge	Test				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Operations & Repairs	34.46	35.28	37.43	35.44	35.72	35.99	36.27	36.55	36.82	37.10
Fuel Costs	7.85	6.28	7.88	8.78	8.85	8.92	8.99	9.05	9.12	9.19
Depreciation	17.70	18.44	18.69	19.78	19.93	20.09	20.24	20.40	20.55	20.71
Hourly Rate	**60.00**	**60.00**	**64.00**	**64.00**	**64.50**	**65.00**	**65.50**	**66.00**	**66.50**	**67.00**

Below is a listing of each cost category, with percentages reflective of the 2014 fleet rate. A further description of each cost category is more fully explained in Section 3.4 of this Exhibit.

Operations & Repair Costs (55% of Fleet Rate)
Fuel Costs (14% of Fleet Rate)
Depreciation (31% of Fleet Rate)

2.3 Material Surcharge Rate

A standard material surcharge rate, which captures supply chain procurement costs benefiting a particular program or project, is applied to material costs. A detailed description of Hydro One’s approach to supply chain management is found in Section 4.0 of this Exhibit.

Material costs charged to a project or program is based on the issue cost from Inventory, which is the Moving Average Price (MAP) or the direct-shipped purchase order price.

On a monthly basis, total monthly material charges are surcharged with a fixed percentage cost to recover costs associated with purchasing, transportation and inventory management. The percentages range from 11% to 17%, depending on work program service requirements. The percentages are derived by assigning the costs of these activities to the work programs based on an annual assessment of the consumption of these services divided by the annual forecast of purchased material.

The costs recovered in the surcharge are as follows:

- Hydro One Costs: Management, demand planning, warehousing and transportation of material, and investment recovery (comprising approximately 60% of the total costs); and
- Inergi Contract Costs: Procurement (comprising approximately 40% of the total costs).

2.4 Other Program and Project Costs

Depending on the nature of the work, Hydro One Distribution's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material.

In terms of estimating and costing of capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. In these cases, the cost of removal work is accounted for as depreciation, and customer contributions are netted against gross capital costs.

Capital work also receives a monthly charge for its share of corporate interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit D1, Tab 4, Schedule 1, Interest Capitalized and Exhibit C1, Tab 5, Schedule 2, Overhead Capitalization Rate.

2.5 Standard Rates

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs. The monthly assignments of residual costs are made to OM&A and Capital based on the program and project cost activities responsible for generating the year-to-date variances.

3.0 FLEET MANAGEMENT SERVICES

Fleet Management Services provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations, including, but not limited to; CSA 225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. Fleet Management Services also ensures that environmental impacts are minimized and line-of-business productivity is optimized by minimizing downtime and travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business by:

- Revising the Company's model for responding to internal customers from fixed zone service to a mobile and fire hall model, with maintenance garages strategically placed throughout the Province to facilitate a more rapid turnaround for vehicle servicing;
- Optimizing the number of geographical locations served through implementation of Garage hubs;
- Reducing equipment downtime and improving our equipment utilization;
- Providing more competitive and cost efficient fleet support, enhanced through the procurement of modern maintenance facilities;
- Adopting a flexible service delivery model that matches the nomadic and variable work program needs of Hydro One's lines of business with service delivery options that mirror private sector practices. Such options include shift work, extended hours of service and mobile service delivery;
- Developing more timely, strategic and cost-efficient processes for equipment procurement and disposal;
- Developing a long-range capital replacement program; and
- Adopting data collection and information management systems that match the nomadic requirements of the Company's business units.

3.1 Maintenance Model

Fleet Management Services has developed a balanced maintenance model for mobile service delivery and centralized facilities. This model provides for 38 provincial locations and balances geographical customer requirements, travel time, third party vendor support and response time. Mobile/satellite repair units minimize costs organizationally by providing timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance.

Services provided to the lines of business meet the rigorous requirements of Fleet Management Services' agreements and are structured as a mobile and fire hall operating model to meet customer requirements.

3.2 Managed Systems

Fleet Management System

The strategic alliance to implement a fleet management system (FMS), developed with Automotive Resources International (ARI) in 2003, was renewed in 2008. In 2013 the contract was extended to 2015 to allow pursuit of a potential amalgamation of a FMS with the Ontario Public Service. The implementation of the FMS created an automated web-based system that uses a single credit card for each vehicle to capture all operating costs including fuel, parts and repairs. The FMS also incorporates programs to manage contracts, such as tender agreements, and the system prescribes spending guidelines and negotiated discounts. The system measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and complaints.

The benefits of the FMS include:

- Improved scheduling of preventative maintenance, reduced repair times, travel time and reduced equipment downtime;
- Increased access to a number of vendors for fuel, repairs and parts, thus minimizing cost and downtime;
- Improved cost and efficiency, through carefully-considered procurement strategies and economies of scale, including improved volume discounts for fuel, parts and service;

- A 1-800 number for repairs, roadside assistance and towing and improved reporting and data collection; and
- Exposure to best practices for fleet management by similar sector organizations.

The FMS uses a variety of linked programs to manage the data and information for all facets of the business, including internal and external repairs. This takes advantage of both internal and external intelligence and technology.

The maintenance program minimizes avoidable and expensive repairs and minimizes equipment downtime, which results in improved equipment utilization. Both internal and external service providers have access to the appropriate information through state-of-the-art automated management systems, allowing for quality decision-making at all levels of the maintenance program. Examples of the information provided include:

- Real time vehicle history;
- Warranty criteria and warranty recovery;
- A work and resources scheduling tool;
- A pending and overdue work information alert system;
- Product information, including vendor-specific information;
- Repair and safe practices manuals;
- Process and policy information;
- Invoice and cost-management details;
- Monthly and ad-hoc reports; and
- Work order management.

Telematics

In 2009, Hydro One Fleet Services entered into a pilot program to install GPS (Global Positioning System) into 500 Transportation and Work Equipment (TWE) units as part of the Hydro One Environmental Plan. From this Pilot Project, Hydro One Fleet Services recorded a number of lessons learned. These lessons were incorporated in the tender for a new generation fleet telematics system for 2,700 fleet vehicles that will provide significant enhancements to operator safety, workplace efficiency and reduction of environmental impacts. This project is currently scheduled to be implemented by end of 2014. The Telematics initiative will allow for continuous improvements and permit implementation of best practices through:

- Improved operator safety through awareness and driver aids;
- Decreased kilometers driven through route optimization;
- Increased productivity/utilization of vehicles;
- Expanded environmental benefits, including increased fuel efficiency and reduction of greenhouse gases;
- Increased fleet response time;
- Providing acceptable data for Fuel Tax Credits;
- Tracking of vehicle condition, including fluid levels, pressures and temperatures; and
- Increased security of fleet vehicles.

3.3 Fleet Complement and Utilization

Fleet Management Services controls and manages approximately 7,300 vehicles and other equipment primarily for Transmission and Distribution work. Inventory levels are controlled and set by the Hydro One lines of business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations and utilization targets. The increase in the fleet complement, therefore, is directly related to the increase in the Company's work on system infrastructure and corresponding staffing levels. Fleet Management Services maintains 38 facilities to support 17 Forestry locations, 1,004 Distribution Stations, 289 Transmission Stations, and 54 Provincial Lines operational centers.

As capital and OM&A investments have been increasing, the options to meet increased equipment demand include the purchase of new equipment, rental of additional equipment or increased utilization of existing equipment. The optimum option is to increase utilization, which minimizes capital investment compared to the option of additional purchases. Simultaneously, it maximizes the advantage of owned core equipment versus the additional cost of external rentals, which is 30 percent higher than owned equipment rates. This assessment is based on an internal comparison of the actual costs of equipment rentals versus those of owned core equipment.

The benefits of improving utilization include:

- decreased long term capital requirements;
- improved ability to respond to fluctuations in work programs; and
- reduced rental costs, with a correspondingly lower impact on the Company's OM&A budget.

Equipment utilization averages have increased from approximately 65 percent in 2001 to approximately 80 percent in 2012. The 2012 average equipment rate is $21.38 per hour; this is established by averaging total annual fleet equipment costs over total annual fleet utilization hours.

3.4 Fleet Management Services Budget

Fleet Management Services' annual budget is developed and managed based on the all-in costs of operating the fleet and the following criteria:

- Historical and forecast fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, and external rentals;
- Historical cost and mechanical fitness evaluations;
- Work program forecasts provided by the lines of business;
- Estimates provided by internal and external providers;
- The requirements of the capital/vehicle replacement program; and
- Projected escalators.

Table 3, below, provides total expenditures on the components comprising the fleet rate for historic, bridge and test years. These expenditures are distributed among each of the 59 classes of vehicles.

Table 3
Fleet Management Services Budget Expenditures
($ Million)

	Historic				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Operations & Repairs	52.9	51.5	55.3	57.1	60.5	62.7	63.7	64.8	66.3	67.7
Depreciation	34.3	34.9	35.3	36.3	37.3	38.3	39.3	40.3	41.3	42.3
Fuel	22.0	28.3	29.1	29.5	30.3	30.8	31.2	32.0	32.9	33.6
Subtotal	**109.2**	**114.7**	**119.7**	**122.9**	**128.1**	**131.8**	**134.2**	**137.1**	**140.4**	**143.6**
Rentals	5.0	1.9	1.1	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total	**114.2**	**116.6**	**120.7**	**124.9**	**130.1**	**133.8**	**136.2**	**139.1**	**142.4**	**145.6**

3.4.1 Operations and Repairs

This cost category primarily consists of repair costs (external and internal labour and parts). The budget is based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculations. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations costs include administration staff and their allocated share of central service support costs (for example, work methods and safety training activities).

3.4.2 Depreciation

The depreciation for each class within the fleet is calculated based on the current depreciation policies in Hydro One, the current composition of the fleet, and annual forecast additions and deletions.

3.4.3 Fuel Cost

Fuel cost per class of equipment is calculated based on past history and current market projections as well as the current composition of the class. Throughout the year, fuel costs are charged directly to the particular piece of equipment consuming the fuel.

3.4.4 External Fleet Rentals

Due to the seasonal and fluctuating nature of the Company's work program, Hydro One Distribution requires the use of externally-owned equipment to meet the peaks in its programs. Using a process similar to that used to cost Hydro One Distribution's own fleet, standard rates are calculated and costs are distributed to the Company's programs and projects.

3.5 Recent Productivity Improvements in Fleet Management Services

Hydro One Distribution supports continuous improvement. This section details current work in progress in fleet management that promotes workplace and operator safety, productivity, efficiency and environmental considerations.

Hydro One Distribution's fleet management system is an automated web-based system under which a single credit card captures all operating costs (including fuel, parts and repairs) for each vehicle. This system is used to measure a variety of targets which identify opportunities to reduce costs and increase productivity efficiencies through strategic procurement practices and economies of scale, including improved volume discounts for fuel, parts and service.

Hydro One Distribution has a maintenance program for its fleet of vehicles. Internal and external service providers are granted access to appropriate information through state-of-the-art management systems linked to Hydro One Distributions fleet management system. This allows for improved work and resource scheduling tools, information alerts and invoice and cost management details, resulting in avoidable and expensive repairs and equipment downtime being minimized and improved fleet efficiency.

As discussed in section 3.2, the Telematics Initiative will allow Hydro One Distribution to continuously improve and implement best practices in operator safety, workplace efficiency and environmental impacts. Operator safety will be improved through awareness and driver aids. Improvements in productivity efficiencies will include decreased kilometers driven through route optimization, increased fleet response time and automated tracking of vehicle condition. Also, with the implementation of telematics, environmental benefits such as increased fuel efficiency and a reduction of greenhouse gases will be realized.

4.0 SUPPLY CHAIN MANAGEMENT

Hydro One delivers end-to-end supply chain services for the Distribution, Transmission, Telecom and Remotes businesses. The focus is on the right product with the right quality, at the right place, right time and at the right cost.

The forecast 2015 costs for Supply Chain Services are expected to be $40.5 million and remain fairly flat through 2019. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials; demand planning, inspection services, transportation, inventory management, and investment recovery of disposed assets.

Supply Chain Services costs are allocated to work programs and projects through the material surcharge rate.

This section describes the budgeted cost levels, followed by a description of the components of Supply Chain Management.

Table 4
Supply Chain
($ Million)

	Historic				Bridge	Test	Test	Test	Test	Test
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Total	38.2	42.9	40.5	40.5	40.2	40.5	39.9	39.5	39.9	40.4

The increase in supply chain costs between 2010 and 2013 reflects the increase in transaction volumes, as well as cost increases related to transportation and warehousing.

Hydro One Distribution's Supply Chain is a service which has been largely outsourced to Inergi L.P. The components of supply chain management performed by Inergi include sourcing (purchase) of materials and services, execution of transportation contracts, and contract management.

4.1 Supply Chain Policies and Procedures

Hydro One Distribution operates a fair and transparent procurement process that gives all companies equal opportunity to do business consistent with its Procurement Policy and Principles.

Tenders and proposals are evaluated based on predefined evaluation criteria by cross-functional teams as required. The outcome of the evaluation is the foundation for awarding procurement contracts.

4.2 Sourcing of Materials and Services

The sourcing of materials and services, primarily carried out within Inergi, includes the following:

- Demand Management and Procurement – Market intelligence with respect to commodities, processing purchase transactions and inspecting and expediting services to ensure delivery to contract commitments.
- Sourcing and Vendor Management – Services to support sourcing all commodities and services which include managing the size and composition of the vendor base and resolving issues.

Hydro One Distribution manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a Company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's five-step process includes spending analysis, market analysis, development of a sourcing strategy, negotiation, award and contract management.

4.3 Inspection Services

Inergi LP is engaged to provide timely inspection services to assure that products are manufactured in accordance to specifications established by Hydro One Distribution, and tracks costs and schedules on a product and project basis.

4.4 Storage and Distribution of Materials - Warehousing

Hydro One Distribution's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This warehouse services two primary customers, Customer Operations and Grid Operations. Customer Operations is further serviced through 88 field service centres and Grid Operations through 21 station locations. The field staff is responsible for receiving shipments and for storing and ordering material. Deliveries to the service centres are contracted to a third party transportation carrier.

The intent of a consolidated warehouse operation is to realize efficiencies through focusing on activities such as:

- Bar coding to improve operating efficiencies such as receipting, cycle counting, shipping and tracking inventory;
- Managing and coordinating the delivery of materials on the scheduled delivery date to the service centres to ensure that the field operation receives the right material at the right time; and
- Improving receipting efficiency by integrating with the contracted transportation company to provide visibility into the supply chain and scheduling the inbound shipment.

4.5 Transportation

Hydro One Distribution manages its inbound and outbound transportation of materials through contracts with third party companies. In 2013, Hydro One Distribution entered into a new transportation contract for material delivery in and out of the central warehouse.

4.6 Investment Recovery

The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range of $2.5 million to $4.4 million per year, and primarily involves vehicle sales and scrap metal. Hydro One Distribution continues to focus on extracting the maximum value possible from the sale of these assets.

A breakdown of the sale of assets is as follows:

Table 5
Breakdown of Sales of Assets through Investment Recovery Program
($ Million)

Type of Sale	Recovery 2010	Recovery 2011	Recovery 2012
Vehicle Sales	1.1	2.0	1.0
Scrap Metal	1.4	2.4	1.6
Total	**2.5**	**4.4**	**2.6**

Note: 2011 Vehicle Sales include a sale of a helicopter ($0.5M)

4.7 Cost Savings from Strategic Sourcing

Between 2008 and 2015**,** due to its collaborative planning and strategic sourcing initiative, Hydro One Networks estimates $141 million in cumulative savings in the purchase of major equipment, commodities and services such as power transformers, circuit breakers, wood poles, distribution transformers, wire and cable, and pole and line hardware. Strategic sourcing results vary from commodity to commodity or from one service to another.

The main benefits of sourcing strategies are described below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;
- Cost reduction by increased leverage of Company-wide expenditures – purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. This eliminates the need to tender and purchase as requirements surface -- an added benefit of this approach;
- Reduced total life cycle cost for materials and services – when purchasing equipment, all aspects are identified to ensure that Hydro One Distribution acquires maximum value for the life cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and inventory requirements, etc. are evaluated to determine where greater efficiencies may be realized;
- Improved security of supply through longer-term agreements. To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One Distribution achieves best value;
- Improved and/or consistent quality of material and services.

Collaborative planning and strategic sourcing will continue to be a major focus, as the Company emphasizes cost control and security of supply while demand in the global utility sector increases.

4.8 Recent Productivity Improvements in Supply Chain Management

Hydro One Distribution is interested in continuous improvement, and supply chain management is one example. This section details some work in progress to provide effectiveness and efficiency gains.

Previously, procurement of material for projects usually occurred after the release of the project. The supply management process is evolving, however, to consider the broader work program over multiple years, and obtain quotes for materials required over multiple delivery dates. This approach assists vendors by allowing them to better plan their activities, and leads to lower costs and a stronger relationship between Hydro One Distribution and the vendor – which has additional benefits if difficulties arise in the supply of materials.

Hydro One Distribution has also developed “outline agreements” with vendors to establish a standing order or relationship for critical materials, such as cable and autotransformers as well as material for day to day consumption. In addition, the Company involves some suppliers in its planning activities, and studies historical buying patterns to assist in planning purchases.

Streamlining standards is another way in which Hydro One Distribution is improving the strategic sourcing process. In addition to simplifying procurement, this also increases both the likelihood that spares will be available for use, and the ease of maintaining a lower inventory.

COMMON CORPORATE COSTS, COST ALLOCATION METHODOLOGY

Allocation of Common Corporate Costs to Hydro One's Distribution and Transmission businesses and to each Hydro One affiliate is based on clearly articulated shared functions and services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Customer Service, Asset Management, Information Technology, and Operating Programs to support the Hydro One Networks' Distribution and Transmission businesses.

CCF&S include Corporate Management, Finance, Human Resources, Corporate Communications & Services, General Counsel & Secretariat, Regulatory Affairs, Corporate Security, Internal Audit and Real Estate & Facilities.

A description of the CCF&S has been provided at Exhibit C1, Tab 2, Schedule 8.

Since 2004, in connection with each cost of service application, Hydro One has commissioned a study by Black and Veatch (B&V) to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The 2013 report on this study is provided as Attachment 1 to this exhibit.

As part of the 2013 study, the cost drivers used to allocate the common corporate costs in EB-2009-0096 were updated to incorporate current information. Updating the driver inputs resulted in a shift in allocated costs from Distribution to Transmission ($2.3 million or 0.5% of the total common corporate costs).

A time study was conducted within Hydro One's Planning & Operating and Customer Service groups. The time study for these groups spanned a four week period ending May 31, 2013 and represented approximately $115 million of labour costs. Incorporating the time study's results caused a shift in allocated costs from Distribution to Transmission ($10.8 million or 2.4% of the total common corporate costs).

Updating the time allocations of the functions and activities of all other groups that did not participate in the time study resulted in a shift from Telecom ($0.6 million or 0.1%), Brampton ($0.4 million or 0.1%) and Remotes ($0.3 million or 0.1%) to Distribution ($0.9 million or 0.2%) and Hydro One's shareholder ($0.3 million or 0.1%). (Percentages are based on total common corporate costs.)

Hydro One accepted the results of the 2013 B&V study as providing a reasonable and equitable approach to the assignment of common corporate costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

The following Tables 1 to 5 provide the annual allocation of 2015-2019 CCF&S costs, respectively to all business units.

Table 1
Allocation of 2015 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.0	0.1
Finance	44.6	25.3	18.0	0.8	0.2	0.3	0.0
Human Resources	13.0	6.9	5.7	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	5.9	6.6	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.2	5.4	4.1	0.1	0.2	0.3	0.1
Regulatory Affairs	21.5	9.3	12.0	0.0	0.0	0.1	0.2
Corporate Security	4.8	2.2	2.5	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.1	0.0	0.0	0.0
Real Estate & Facilities	61.4	36.6	24.8	0.0	0.0	0.0	0.0
Total CCF&S Costs	**177.1**	**96.8**	**77.2**	**1.3**	**0.5**	**0.9**	**0.4**

Table 2
Allocation of 2016 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.0	0.1
Finance	43.8	24.9	17.6	0.7	0.2	0.3	0.0
Human Resources	12.2	6.5	5.4	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	5.9	6.6	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.2	5.4	4.1	0.1	0.2	0.3	0.1
Regulatory Affairs	22.4	9.8	12.4	0.0	0.0	0.1	0.2
Corporate Security	4.6	2.1	2.4	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.1	0.0	0.0	0.0
Real Estate & Facilities	61.3	36.6	24.7	0.0	0.0	0.0	0.0
Total CCF&S Costs	**176.1**	**96.4**	**76.7**	**1.2**	**0.5**	**0.9**	**0.4**

Table 3
Allocation of 2017 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.0	0.1
Finance	42.9	24.4	17.3	0.7	0.2	0.3	0.0
Human Resources	12.1	6.5	5.4	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	6.0	6.6	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.2	5.4	4.2	0.1	0.2	0.3	0.1
Regulatory Affairs	21.5	9.2	12.1	0.0	0.0	0.1	0.1
Corporate Security	4.6	2.1	2.4	0.0	0.0	0.0	0.0
Internal Audit	3.6	2.4	1.1	0.1	0.0	0.0	0.0
Real Estate & Facilities	62.4	37.2	25.2	0.0	0.0	0.0	0.0
Total CCF&S Costs	**175.3**	**96.0**	**76.7**	**1.2**	**0.5**	**0.9**	**0.3**

Table 4
Allocation of 2018 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.5	2.8	2.4	0.1	0.1	0.0	0.1
Finance	42.7	24.3	17.2	0.7	0.2	0.3	0.0
Human Resources	12.3	6.6	5.4	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.8	6.0	6.7	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.4	5.5	4.2	0.1	0.2	0.3	0.1
Regulatory Affairs	23.3	9.9	13.2	0.0	0.0	0.1	0.2
Corporate Security	4.7	2.2	2.4	0.0	0.0	0.0	0.0
Internal Audit	3.7	2.5	1.2	0.1	0.0	0.0	0.0
Real Estate & Facilities	63.8	38.1	25.8	0.0	0.0	0.0	0.0
Total CCF&S Costs	**179.2**	**97.9**	**78.5**	**1.2**	**0.5**	**0.9**	**0.4**

Table 5
Allocation of 2019 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.5	2.8	2.4	0.1	0.1	0.1	0.1
Finance	43.6	24.7	17.6	0.7	0.2	0.3	0.0
Human Resources	12.4	6.6	5.5	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.9	6.1	6.7	0.0	0.0	0.1	0.0
General Counsel & Secretariat	10.5	5.5	4.2	0.1	0.2	0.3	0.1
Regulatory Affairs	22.9	9.7	12.9	0.0	0.0	0.1	0.2
Corporate Security	4.8	2.2	2.5	0.0	0.0	0.0	0.0
Internal Audit	3.8	2.5	1.2	0.1	0.0	0.0	0.0
Real Estate & Facilities	66.2	39.4	26.8	0.0	0.0	0.0	0.0
Total CCF&S Costs	**182.6**	**99.5**	**79.8**	**1.2**	**0.5**	**1.0**	**0.4**

REVIEW OF ALLOCATION OF COMMON CORPORATE COSTS (DISTRIBUTION) – 2013

B&V PROJECT NO. 174074

PREPARED FOR

Hydro One Networks Inc.

19 SEPTEMBER 2013

BLACK & VEATCH
Building a world of difference.

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I. Summary

A. BACKGROUND

Black & Veatch Corporation ("B&V" or "we") is pleased to submit to Hydro One Networks Inc. ("Hydro One") this Report on our Review of Allocation of Common Corporate Costs (Distribution)-2013 ("2013 Review").

In 2004, B&V was engaged by Hydro One to recommend a best practice methodology to distribute Common Corporate Costs to Hydro One and its subsidiaries and partnership (identified in Table 1). Common Corporate Costs are the costs to provide certain functions and services (identified in Table 2), including those performed by Inergi LP, to Hydro One and its subsidiaries and partnership. B&V recommended, Hydro One adopted, and the Ontario Energy Board ("OEB") accepted a methodology to distribute those costs, as described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Common Costs Report").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with subsequent reports issued, as follows:

B&V REVIEW	BUSINESS PLAN	B&V REPORT
2006 Review	BP 2007-2011	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	BP 2009-2013	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	BP 2010-2014	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	Updated BP 2010-2014	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010
2012 Review	BP 2012-2016	*Review of Shared Services Cost Allocation (Transmission) – 2012* dated February 1, 2012

The OEB-accepted methodology to distribute the Common Corporate Costs has been applied by Hydro One to its Business Plan for 2014-19 ("BP 2014-19") data. This Report describes the "2013 Review" that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2014-19, and presents B&V's conclusions.

B. HYDRO ONE ORGANIZATION

Hydro One Inc. is wholly owned by the Province of Ontario. It operates through the wholly-owned subsidiaries and partnership listed in Table 1. The OEB regulates, separately, the business units identified as such in Table 1. Each regulated business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

Table 1 - Business Units

SUBSIDIARY	BUSINESS UNIT	REGULATED	DESCRIPTION
Hydro One Networks Inc.	Distribution	Yes	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.3 million customers.
	Transmission	Yes	Owns and operates substantially all of Ontario's electricity transmission system.
Hydro One Brampton Inc	Brampton	Yes	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Hydro One Remote Communities Inc	Remotes	Yes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
Hydro One Telecom Inc.	Telecom	No	Sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.
Hydro One Inc.		No	Represents activities performed exclusively for the benefit of the shareholder of Hydro One Inc. Most costs it incurs are for the benefit of the other businesses, and are allocated to them.
B2M Limited Partnership	B2M Transmission Line	Yes	Will own 100% of a continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching station. This business is included in the Transmission business.

C. FUNCTIONS AND SERVICES IN COMMON CORPORATE COSTS

Hydro One provides the functions and services identified in Table 2, to the businesses identified in Table 1. Exhibit A further describes the functions and services provided. The BP 2014-19 includes 2015 Common Corporate Costs totaling approximately C$410.6 million incurred to perform the relevant functions and services; and the annual total Common Corporate Costs are presented in Table 3.

Approximately 30% of the Common Corporate Costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). Common Corporate Costs includes the cost included in BP 2014-19 for sustainment activities outsourced to Inergi services pertaining to infrastructure/data centre support services, application management services, disaster recovery services, end-user services, desk-side management services and service management.

Table 2 - Functions and Services in Common Corporate Costs

Hydro One Inc. Corporate Office ▪ President/CEO Office ▪ Chair ▪ CFO's Office ▪ Treasurer's Office ▪ Board of Directors ▪ Corporate Secretariat ▪ General Counsel – VP ▪ Pension Cost ▪ Donations	**Shared Services** ▪ Treasury ▪ Corporate Controller ▪ Taxation ▪ Outsourcing Services ▪ Real Estate ▪ Regulatory Affairs ▪ Business Planning & Decision Support
Operations ▪ Business Architecture ▪ Power Systems Information Technology (PSIT) ▪ Business Information Technology (BIT) ▪ Security Operations ▪ Distribution Business Development *(Note 1)* ▪ Transmission Projects Development *(Note 1)* ▪ Asset Strategy *(Note 1)* ▪ Network Operations *(Note 1)* ▪ Transmission Asset Management *(Note 1)* ▪ SVP Planning & Operating *(Note 1)* ▪ Labour Relations ▪ EVP Office – Operations	**Customer Service** ▪ Customer Care Services *(Note 1)* ▪ Strategy and Conservation *(Note 1)* ▪ Distributed Generation *(Note 1)* ▪ Customer Business Relations *(Note 1)* ▪ TxDx Settlements *(Note 1)* ▪ Account Management Director *(Note 1)* ▪ Advanced Distribution *(Note 1)* ▪ Pricing *(Note 1)* ▪ VP Customer Service *(Note 1)* ▪ SVP Customer Operations *(Note 1)* ▪ Value Growth
Corporate Relations ▪ Corporate Communications and External Relations and Executive Office ▪ First Nations and Métis Relations	**Inergi LP (outsourced services)** ▪ Customer Support Services ▪ Settlement ▪ Finance ▪ Human Resources - Pay Services ▪ Accounts Payable
People and Culture	**ETS- Applications Support and Infrastructure Support**
Internal Audit	**Telecom Services**
General Counsel & Secretariat	
Note 1- Department participated in 2013 Time Study; see Section V.	

D. B&V'S ASSIGNMENT

For the 2013 Review, our assignment was to:

a. Evaluate whether the existing Common Corporate Cost Allocation Methodology continues to be appropriate for Hydro One, and identify changes that are necessary or desirable.

b. Review Hydro One's application of the OEB-accepted Common Corporate Cost Allocation Methodology to the BP 2014-19.

The organization presented in Table 2 reflects the creation of new departments, realignment of departments among groups, and realignment of functions among departments, that Hydro One believes will allow it to serve its customers most effectively and efficiently, based on the current business and regulatory environment.

The Common Corporate Costs Model for BP 2014-19 reflects these organizational changes. We reviewed the cost driver for each activity to determine its continued applicability, and where necessary, the development of the cost driver was updated to reflect the organizational changes.

Concurrently with this 2013 Review, B&V reviewed and issued reports on Hydro One's Overhead Capitalization Rate methodology, Common Assets allocation and Allocation of Common Corporate Costs to the B2M Limited Partnership.

E. OVERVIEW OF METHODOLOGY

The B&V methodology for allocating the costs of Hydro One's Common Corporate Costs was designed to address the following considerations:

- Compliance with OEB precedent including Docket RP-2002-0133 (*In The Matter Of The Ontario Energy Board Act, 1998)*,
- S.O. 1998, c.15
- Compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters ("Code")
- Cost incurrence- Are the costs needed to perform services required by the business units?
- Cost allocation- Are costs appropriately allocated among business units?
- Cost/benefit- Do benefits received equal or exceed the cost?

An overview of the B&V cost allocation methodology is described below:

- Identify the functions and services included in Common Corporate Costs
- Identify activities that are performed to provide those functions and services
- Based on time and/or cost studies, distribute the annual departmental costs in the BP 2014-19 among the activities performed by that department in providing the functions and services
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when direct assignment is not possible

A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The direct assignment of costs when possible, and the use of cost drivers to allocate costs when direct assignment is not possible, is consistent with OEB precedent, including Docket RP-2002-0133. The guiding principle used by the B&V methodology to assign cost drivers is cost causation.

Cost drivers are discussed in Section II-D. The different types of cost drivers are described in Exhibit B.

F. SCOPE OF WORK

Consistent with B&V's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and any actual contrary knowledge, but without our independent confirmation. All dollar amounts in this Report are stated in Canadian dollars.

G. RESULTS AND CONCLUSIONS

B&V believes that the current cost allocation methodology continues to be appropriate for Hydro One because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice) and promotes transparency and efficiency.

Table 3 presents the results of Hydro One's distribution of the Common Corporate Costs in BP 2014-19, annually for 2015-19, among its Distribution, Transmission and other businesses.

Table 3 - Distribution of Annual Common Corporate Costs for 2015-2019

BUSINESS	2015	2106	2017	2018	2019
($ Millions)	**$**	**$**	**$**	**$**	**$**
Transmission	$191.1	$188.7	$186.3	$188.2	$190.6
Distribution	208.1	205.8	205.3	208.7	212.4
Other	11.4	11.4	11.3	11.4	11.6
Total	**$410.6**	**$405.9**	**$402.9**	**$408.3**	**$414.6**
(% of Total)	**%**	**%**	**%**	**%**	**%**
Transmission	46.5%	46.5%	46.2%	46.1%	46.0%
Distribution	50.7%	50.7%	51.0%	51.1%	51.2%
Other	2.8%	2.8%	2.8%	2.8%	2.8%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Based on our review, B&V believes that the results of Hydro One's application of the B&V Common Corporate Cost Allocation Methodology to its BP 2014-19 data reflects a cost causation-based distribution of the Common Corporate Costs and conforms to the OEB-accepted methodology. The annual results for years 2015-2019 are shown in Table 3.

B&V also notes that Hydro One management believes that the existing methodology is appropriate for the company, the cost allocation process receives strong support from Hydro One management and is well integrated into the budgeting process and the Common Corporate Costs Model is updated periodically to reflect current information.

II. Statement of Approach

This section presents the approaches used by B&V to evaluate whether the existing Common Corporate Cost Allocation Methodology continues to be appropriate for Hydro One, and to review Hydro One's application of the methodology to the BP 2014-19 costs of providing the functions and services included in Common Corporate Costs.

A. EVALUATE COST ALLOCATION METHODOLOGY

The Common Corporate Cost Allocation Methodology was first applied to Hydro One's Business Plan 2006-10. Hydro One has asked B&V to evaluate whether the methodology is still appropriate, and what changes if any could be considered. B&V's approach is discussed in detail in Section III.

B. REVIEW APPLICATION OF COST ALLOCATION METHODOLOGY TO BP 2014-19

In preparing the 2013 Review, B&V performed the following tasks:

Task 1. Reviewed Hydro One's current organizational structure and identified departments that perform the functions and services included in Common Corporate Costs.

Task 2. Identified the activities performed by each department in order to provide the functions and services identified in Task 1.

Task 3. Determined the Common Corporate Costs in BP 2014-19 to perform the functions and services in Task 1.

Task 4. Identified the business units that use the functions and services included in Common Corporate Costs.

Task 5. Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2014-19 for departments identified in Task 1, among the activities identified in Task 2.

Task 6. Directly assigned activity costs to business units where a direct relationship exists.

Task 7. For activities where less than all of the BP 2014-19 costs were directly assigned to business units in Task 6, assigned a cost driver that reflects cost causation.

Task 8. Populated the cost drivers.

Task 9. Performed the 2013 Time Study

Task 10. Computed total Common Corporate Costs allocated to each business unit.

Task 11. Performed analytical review of results.

Task 12. Reviewed the Common Corporate Costs used to perform the computations.

C. PRINCIPLES OF COST DISTRIBUTION

There are two methods to distribute shared costs among business units – Direct Assignment and Allocation. *Direct Assignment* is used when it can be reasonably determined that all or a portion of an activity is performed for a particular business unit. Approximately 55% of Common Corporate Cost in the BP 2014-19 were assigned directly to one or more of Hydro One's business units.

Allocation is used when more than one business unit uses an activity, but the portions of the activity that each uses cannot be directly established. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The principles used by B&V to assign cost drivers are discussed in Section II.D below.

Direct Assignment is preferable to Allocation because it is based on a more direct relationship between activities and costs.

D. COST DRIVERS

As stated above, a cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The guiding principle that B&V uses in assigning cost drivers is cost causation. Cost causation means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair alternative treatment.

Other factors considered in assigning cost drivers include:

- Practicality – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- Stability – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.
- Materiality – When choosing between cost drivers, small differences can often be ignored in favor of Practicality and Stability (see above).

E. TYPES OF COST DRIVERS

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts.

Internal drivers are based on values computed as an integral part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities. Exhibit B further describes different types of cost drivers.

III. Evaluate Cost Allocation Methodology

The Common Corporate Cost Allocation Methodology was first applied to Hydro One's Business Plan 2006-10. B&V has also reviewed the application of the methodology to subsequent business plans, as listed in Section I.A. The purpose of this portion of the 2013 Review was to evaluate if the methodology is still appropriate, including reviewing changes recommended in the past.

Based on our discussions with Hydro One personnel and review of the Common Corporate Costs Model, B&V determined that the methodology continues to be appropriate because:

- It meets best practices because it distributes costs based on cost causation, including the use of direct assignment when possible, and then cost drivers
- It has been accepted by the OEB
- It has the support of Hydro One management, and is understood and accepted by the Hydro One business units
- It allows the business units to determine precisely what amounts they are charged by department and by activity within the department; this transparency provides a basis for understanding the nature of the charges and value of the services received
- It is well-integrated with Hydro One's annual Business Planning process and produces reasonably stable results over time
- It accommodates changes in Hydro One's organization, and the Common Corporate Costs Model can be adapted easily to reflect those changes

In addition, B&V reviewed the trade-offs discussed in the 2012 Review, and believes that Hydro One has made the appropriate choice in each of those areas, as discussed below:

- While **units-of-service billing** would seemingly be a more precise distribution of costs; in fact, there is no basis for charging time for many activities (e.g., human resources, IT infrastructure), and it would be complex and costly to administer.
- Automating the **Common Corporate Costs Model** would require an investment of Information Technology ("IT") time. We do not believe the annual savings of several hours would be worth the investment. In addition, some tasks, such as determining direct assignments or selecting allocators, cannot be automated.
- The departments in the 2013 Time Study can determine with reasonable accuracy the time they spend on programs and projects because the programs and projects are clearly defined, and the work is not seasonal. However, **using concurrent time studies for other departments** is not practical, because the programs and projects that other departments complete may not be clearly defined, and the work may be seasonal. In addition, it would add significantly to cost and complexity.

B&V believes that the current cost allocation methodology continues to be appropriate for Hydro One, because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice), and promotes transparency and efficiency.

IV. Review Application of Methodology to BP 2014-19

In this Section we will discuss each of the Tasks performed in the Scope of Work, as stated in Section II-B. This includes the purpose of the Task, the steps performed, the source of the information and the results.

Task 1. Reviewed Hydro One's current organizational structure and identified departments that perform the functions and services included in Common Corporate Costs.

The purpose of this Review was to evaluate the allocation of the Common Corporate Costs among the businesses that use the functions and services.

The organization of Hydro One Inc. is described in Section I.B. The functions and services support the Distribution business and the Transmission business, and the other businesses listed in Table 1. The departments that perform the functions and services in Common Corporate Costs are listed in Table 2. Exhibit A further describes the functions and services. This information was provided by Hydro One in discussions and documents.

Task 2. Identified the activities performed by each department in order to provide the functions and services identified in Task 1.

The purpose of this task was to identify the activities that are performed in order to provide each of the functions and services in Common Corporate Costs.

Functions and services (identified in Task 1) are performed for the benefit of the business units. Activities (discussed in this Task 2) are the tasks performed in order to provide the functions and services. Activities are measured in the amount of resources used.

To distribute the resources required to provide the functions and services included in Common Corporate Costs among the business units on the basis of cost causation, the activities performed were identified by Hydro One. The activities identified accounted for approximately 93% of the total 2015 Common Corporate Costs in BP 2014-19 (time for labour resources, costs for non-labour and Inergi resources). The remaining activities are non-labour costs of departments in the 2013 Time Study (4% of Common Corporate Costs), General Departmental Expenses (2%) and General Departmental Activities (1%).

Task 3. Determined the Common Corporate Costs in BP 2014-19 to perform the functions and services in Task 1.

In this task, we obtained the BP 2014-19 costs for the departments that provide the functions and services included in Common Corporate Costs. Hydro One provided to B&V the labour and non-labour portions of the BP 2014-19 for each of these departments, as well as descriptions of major non-labour cost items.

Task 4. Identified the business units that use the functions and services included in Common Corporate Costs.

The business units that use the functions and services included in Common Corporate Costs are listed in Table 1. The information was provided by Hydro One and confirmed by the service recipients.

Task 5. Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2014-19 for departments identified in Task 1, among the activities identified in Task 2.

The purpose of this task was to distribute the resources (time for labour and costs for non-labour and Inergi) required for each of the functions and services identified in Task 1, among the activities identified in Task 2. In subsequent tasks, the cost of each activity was either directly assigned to one or more business units or allocated using cost drivers.

Labour costs

To distribute budgeted labour costs, Hydro One department managers determined the portion of annual time spent by the personnel under their supervision on each of the activities identified in Task 2. Some managers based their estimates on concurrent time records that they maintain, some conducted interviews with their personnel, and some used their informed judgment. The information provided by the managers was reviewed by Hydro One Inc. and B&V, and was found to be reasonable and consistent with prior distributions of resources.

The departments in the study represent approximately $115 million of annual labour costs, equal to approximately 28% of annual Common Corporate Costs and 50% of annual labour costs, were directly assigned based on the 2013 Time Study, discussed in Section V.

Non-labour costs

To distribute budgeted non-labour costs, items totaling $41M, or 87% of the 2015 total of $47M, were examined and distributed based on direct assignment or allocation; this amount includes non-labour costs of departments in the 2013 Time Study. This included OEB invoices, communications programs, insurance costs and claims, human resources programs, labour relations programs, Bill 198 consultant, actuarial consultants and audit fee. The balance of non-labour costs includes items such as training and development, non-specific expenses and general expenses.

Inergi costs

The Common Corporate Costs representing functions and services provided by Inergi were distributed among the activities, based on information provided by Hydro One Inc., assignments and allocations by Hydro One and B&V, and the application of judgment by Hydro One and B&V. The approach for each of the functions and services provided by Inergi is described below. Exhibit A describes these services in greater detail.

- **Customer Support Operations–** Costs were assigned among activities based on the estimated portion of total amounts paid to Inergi to perform the function. All of the activities are related directly to the Distribution business.
- **Settlement –** Only one activity, no distribution of costs among activities required. The resources used in the activity were directly assigned between Distribution and Transmission based on estimated effort.
- **Finance –** Costs were assigned among activities based on estimated portion of total amount paid to Inergi to perform the function.
- **Human Resources –** Costs were assigned among activities based on estimated effort by Inergi. All activities were allocated among the business units based on headcount.

- **Enterprise Technology Services –** ETS includes the cost of sustainment activities for baseline infrastructure and for support of major application groups (i.e., customer service; finance; human resources; Passport / Cornerstone; Market Ready; telecom; and Smart Meter). The cost of baseline infrastructure services was based on contract amounts. The balance of costs were distributed among the applications groups based on the relative costs of Inergi support, the number of applications supported and judgment as to the complexity of the applications.

Task 6. Directly assigned activity costs to business units

The purpose of this task was to assign, among the business units listed in Task 4, the resources (time for labour resources and costs for non-labour and Inergi resources) for each activity listed in Task 2. In Task 10, these assignments were used to distribute the cost of each activity among the business units. This task was performed concurrently with Task 5 – Distributed Common Corporate Costs (time for labour resources and cost for non-labour and Inergi resources) reflected in BP 2014-19 for departments identified in Task 1, among the activities identified in Task 2.

For the activities listed in Task 2, Hydro One departmental managers distributed the resource costs among one or more business units, based on the business units that caused the costs to be incurred. When possible, all or a portion of costs were assigned directly.

Any portion of an activity that was not directly assigned was allocated among business units using cost drivers, as described in Task 7. Each activity was determined to be:

- Caused by Distribution and Transmission, and the split cannot be determined or
- Caused by Distribution and / or Transmission and at least one other business unit, and the split cannot be determined.

Task 7. Assigned cost drivers

As discussed above, the costs of activities were directly assigned to business units when possible. The purpose of this task was to select cost drivers for the portion of costs which were not directly assigned in Task 6. In Task 10, the cost drivers were used to distribute the activity costs among the business units.

The principles that B&V used to assign cost drivers are discussed in Section II.D- Cost Drivers. B&V selected cost drivers based on applying the principles discussed above, its experience in performing cost allocation studies, consultations with Hydro One as to the nature of each activity, and industry practices and regulatory requirements.

Section II.E Types of Cost Drivers describes the types of cost drivers.

Table 4 summarizes the direct assignments and types of costs drivers used to distribute the Common Corporate Costs among the business units. Amounts include the Inergi charges.

Table 4 - Direct Assignments and Cost Drivers for Common Corporate Costs in BP 2014-19

TYPE	2015	2106	2017	2018	2019
(% of Total)	%	%	%	%	%
Direct Assignment	56.3%	56.9%	57.2%	57.5%	57.4%
Physical	11.2%	11.2%	11.2%	11.1%	11.1%
Financial	11.6%	11.6%	11.6%	11.5%	11.6%
Internal	20.9%	20.3%	20.0%	19.9%	19.9%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Task 8. Populated cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to each business unit, in order to distribute the costs of each activity among the business units. The supporting information was provided by Hydro One.

Task 9. Reviewed 2013 Time Study

This Task is discussed in Section V.

Task 10. Computed total common corporate costs for each business unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6, and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the activity cost to be allocated by the cost driver value for the business unit.

Task 11. Performed analytical review

The purpose of this task was to compare the results of the distribution of the BP 2014-19 Common Corporate Costs among the business units to the results in the 2012 Review, 2010 Review, 2009 Review, 2008 Review and 2006 Review, and to understand the differences.

The proportions of the total cost distributed to each business unit have been reasonably similar over time and differences are explained by additions and removal of departments from the Common Corporate Costs (i.e., the 2012 Review included Asset Management departments and Operating group departments, and excluded Materials Surcharge, for the first time), changes in allocations of time, changes in allocator values and changes in departmental functions and activities.

Task 12. Reviewed Common Corporate Costs Model

The purpose of this task was to review the Common Corporate Costs Model that Hydro One has developed for allocating the Common Corporate Costs, to determine if it properly reflects and models the OEB-approved cost allocation methodology for those costs included in the BP 2014-19.

B&V first reviewed Common Corporate Costs Model in connection with our 2008 Review, and has reviewed the model for each of the subsequent reviews performed, including this 2013 Review. The model is updated periodically to reflect organizational changes; Business Plan costs; additions to and deletions of departmental activities; time and cost distributions among activities; assignments of allocators; and cost driver values.

The Common Corporate Costs distributes departmental costs among activities (Task 6), then distributes the cost of each activity based on direct assignment or cost drivers (Task 10).

Based on our review, the Common Corporate Costs properly implements the OEB-accepted methodology for distributing the costs of corporate functions and services in the BP 2014-19, and continues to produce a cause-based allocation of costs.

V. 2013 Time Study

Hydro One employees representing approximately $115 million of annual labour costs participated in a time study for the four-week period ending May 31, 2013 ("2013 Time Study").

The departments that participated in the 2013 Time Study are identified in Table 2 (*Note 1* is next to the department name). The responsibilities of these departments are included in Exhibit A.

The personnel in these departments are able to determine with reasonable accuracy, on a current basis, the time they spend on Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects because the programs and projects on which they work are clearly defined.

A properly performed time study measures cost causation and is widely accepted as a basis for assigning costs. B&V participated in the design, administration and supervision of the 2013 Time Study. B&V's responsibilities included reviewing and advising Hydro One personnel with respect to study design and communication materials, reviewing time study results and the consolidation of the results, and confirming the completeness of the time study and its consistency with the study design. The methodology was the same as for prior time studies conducted by B&V for Hydro One.

It was not practical to perform a full-year study, but the results for a four-week period are believed to be representative of the full-year. To support this judgment, B&V reviewed the previous Hydro One time studies, which were completed at different times during the year, and found that the results were reasonably similar to the 2013 Time Study results.

B&V found that the 2013 Time Study was appropriately designed and completed, the results were correctly compiled, and the methodology was the same as for prior Hydro One time studies performed in connection with B&V's cost allocation reviews. Therefore, B&V concluded that the 2013 Time Study results were a proper basis for directly assigning the costs of the departments included in the study between the Distribution and Transmission business units.

Exhibit A: Functions and Services in Common Corporate Costs

FUNCTIONS AND SERVICES	DESCRIPTION
Hydro One Inc. Corporate Office (HOI)	
President / CEO Office	Leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develop and update strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
CFO's Office	Provide Hydro One and subsidiaries with strategic review and approval for all financial and investment decisions. Review policies and procedures, treasury operations and tax planning, financial control and reporting.
Treasurer's Office	Debt and equity issuance, capital structure management and oversight of Finance- Treasury function.
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
Corporate Secretariat	Provide direction and analysis in areas of: Board and Committee(s); Office of Chair and Board members; Code of Business Conduct; Community Citizenship; Freedom of Information and Privacy, Corporate Archives, Corporate Records, Corporate Secretariat.
General Counsel- VP	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Pension Cost	Pension fund contributions.
Donations	Includes donations to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way and local community causes. Costs are directly assigned to Shareholder only.
Operations	
Business Architecture	Application support and training; Business systems architecture; Reporting & analytics; Manage key asset customer database; provide integrated systems support; support Cornerstone.
Power Systems Information Technology (PSIT)	Applications; Compliance security; Data services; Information services; IT operations; System architecture.
Business Information Technology (BIT)	Information technology security; Enterprise IT architecture; Service delivery; Technology services; Governance of IT architecture, Business analysis and information management, Project management; Inergi & Telecom services management.
Security Operations	Incident reporting and security awareness; Threat intelligence gathering; Physical security and asset threat and risk assessments; Investigations; Theft of electricity consultation and detection; Workplace violence prevention and response; Contract security

FUNCTIONS AND SERVICES	DESCRIPTION
	procurement assistance; Overall security and asset protection advice; Security infrastructure Capital and OM&A investment planning and project management.
Distribution Business Development	Responsible for all distribution-related activities other than operations; includes system assessment and planning; conditions of service; connection studies and connection impact assessments for distributed generation (DG); DG enablement; development project management; management of joint use process/contracts.
Transmission Projects Development	Focuses on transmission capital projects and programs that expand, enhance, upgrade, and improve our transmission system. Areas of focus include area supply, network transfer capability, transformer station upgrades, load customer connections, transmission connected generation, protection and control development, and special studies.
Asset Strategy	Align corporate strategy with asset management, to ensure that investment plans align with business plan. Areas of focus include: .10-year transmission and distribution planning; apply risk methodology in asset planning; asset analytics process improvement project (PIP); rate case filings; NERC/NPCC Reliability Standards and Compliance; develop strategic asset management policies and processes; plan response to emergency disaster and business continuity.
Network Operations	Operates the largest electricity delivery system in Ontario and one of the largest in North America for the needs of the Province of Ontario. Hydro One has a highly skilled and experienced workforce using first-class operating systems located in a state-of-the-art Control Centre. Hydro One is a team working together and safely to ensure Ontario has a safe, reliable supply of electricity.
Transmission Asset Management	Accountable for all transmission asset planning, TX asset strategies, investment prioritization, order book management, business case approvals and support of business planning and regulatory processes.
SVP- Planning and Operating	Oversees Distribution Business Development, Transmission Projects Development, Asset Strategy, Network Operation and Transmission Asset Management.
Labour Relations	Provide full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. Involves interaction with 21 unions and 24 collective agreements.
EVP Office- Operations	Oversight of Operations group.
Corporate Relations	
Corporate Communications and External Relations and Executive Office	Support all external and internal communications initiatives. Interact with most other Hydro One departments; special focus on Customer Service. Support major projects including: development of partnership activities; coordinate with external energy agencies (e.g. OPA, IESO),

FUNCTIONS AND SERVICES	DESCRIPTION
	Ministries in Ontario Public Service and internal Hydro One resources. Participate in pre-public consultations with municipalities and First Nations. Support customer strategy, rate strategy, distribution generation strategy; develop working relationships with customers, regulators, shareholder, lenders; labour relations; corporate culture.
First Nations and Métis Relations	Provide First Nations and Métis consultation advice and support; Advise re First Nations and Métis HR strategies; Provide strategic advice to Remotes with respect to First Nations and Métis issues.
People and Culture	
People and Culture	Primarily employee-related services, including administer compensation & benefits programs; decision support for business units; talent management (hiring, succession, development, coaching; high potential employee assessments); recruitment and diversity (diversity programs, grad program, student/co-op, line of business resourcing); data administration; consulting support to LOBs and corporate functions; VP Human Resources.
Inernal Audit	
Internal Audit & Risk Management	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.
General Counsel & Secretariat	
General Counsel & Secretariat	Provides legal advice to all business units, acting as an internal "law firm" for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Shared Services	
Treasury	Risk management including insurance purchasing; insurance claims settlement; financial risk management; cash & banking operations; debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders; funds management; investor relations-shareholders, creditors, equity analysts & rating agencies; support business activities; project management.
Corporate Controller	Corporate Accounting & Reporting; Revenue Management; Financial Modeling & Analysis; Accounting Policy; Internal Control; IFRS / US GAAP; Inergi Finance; Bill 198; Corporate Compliance.
Taxation	Meet internal and external tax compliance requirements and reduce overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, HST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes and government tax audits.

FUNCTIONS AND SERVICES	DESCRIPTION
Outsourcing Services	Manage overall business relationship between Hydro One and Inergi LP.
Real Estate	Manage and acquire rights of way and easements; manage property taxes; manage SLU revenue programs; manage Employee Relocation Program.
Regulatory Affairs	Coordinate applications with OEB; compliance with OEB orders; design and implement regulatory policy; manage relationship with OEB. Tasks include: cost allocation and rate design for regulated Tx and Dx, especially rate structures and rates for Tx and Dx tariffs; implement approved rates; support transmitters' representative on IESO Technical Panel; manage MV Star to support settlement. Includes: Direct billed OEB costs for Tx and Dx; Direct billed NEB costs for Tx; Costs of Rate Hearings before the OEB for Tx and Dx.
Business Planning and Decision Support	Financial modeling & analysis; corporate planning & reporting; regulatory finance; decision support to the lines of business
Customer Service	
Customer Care Services	Service the approximately 1.1 million distribution customers. Improve customer satisfaction through strategic system and process enhancements, effective services contracting, proactive communications and quality programs. Service programs include meter reading, billing, settlements, customer contact handling and collections. Project work includes regulatory compliance initiatives and service enhancements.
Strategy and Conservation	Design and deliver energy conservation and demand management incentive based programs; Leverage Smart Grid investments to provide customer enablement of new technologies for energy management; Co-ordinate Greener Choices program; Provide input to Corporate Strategic Plan and develop recommendations on emerging strategic opportunities.
Distributed Generation	Develop, manage and look for efficiencies in the process (application to connection) for generators connecting to Hydro One's distribution system. Coordinate status meetings with internal stakeholders. Manage relationship of generators through Account Executives, Customer Advisory Board, DG Consultation Forum. Perform capacity screenings. Provide operating maps. Perform pre-FIT consultations. Manage Connection Cost Agreement and Distribution Connection Agreement.
Customer Business Relations	Manage relationships with Hydro One's large customers including over 90 Transmission-connected Industrials, 79 LDCs and 33 Transmission-connected Generators, representing almost 70% of Hydro One's revenues. Includes Operating Support; Account Executives; Contract Management; and Customer Programs.
TxDx Settlements	Ensures the integrity of financial transactions between Hydro One, the Independent Electricity System Operator ("IESO"), and applicable customers, both load customers and distributed generators.
Account Management Director	Oversees Account Management departments including CBR, DG, and

FUNCTIONS AND SERVICES	DESCRIPTION
	TxDx Settlements.
Advanced Distribution	Ensure business plans and assumptions are aligned with corporate strategy; evaluate emerging and approved strategies for alignment and facilitate corrective action.
Pricing	Accountable for the price side and conditions of service side of the customer values proposition; provide load forecasts; provide strategic and analytical support to load research and CDM initiatives.
VP Customer Service	Oversees Customer Service group, which has overall accountability for relationship, affordability and value proposition for products and services provided to customers. Includes bill management, major accounts and value-added services (e.g. conservation). Customer Service also responsible for Advanced Distribution System Project and Smart Meters.
SVP Customer Operations	Oversees the departments Customer Care, strategy and Conservation, and Account Management.
Value Growth	Seeks ways to leverage Hydro One's core competencies to increase overall value and drive down average cost to serve. Costs are directly assigned to Shareholder only.
Inergi LP (outsourced services)	
Customer Support Operations	Inbound call handling; bill production; collections; data services.
Settlements	Settlement and reconciliation services for wholesale and retail markets.
Finance and Accounting Services	Accounts Payable; Accounts Receivable (non-energy); Fixed asset and project cost accounting; general accounting and planning, budgeting and reporting
Human Resources- Pay services	Payroll and related services
Accounts Payable	Invoice processing and payment
Inergi ETS	
Infrastructure Support	Support IT infrastructure including platforms, servers, printers, workstations, IT communications, Help Desk.
Applications Support	Supports IT applications: Customer Support Operations, Finance, Human Resources / Cornerstone, Passport / Cornerstone, Market Ready, Telecomm Services; Smart Meter.
Telecom Services	
Telecom Services	Provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.

Exhibit B: Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), number of workstations, invoices to vendors
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets
Driver xBusiness Unit	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for Inergi Finance Fixed Asset Accounting is Gross Utility Plant, but Brampton business unit performs its own fixed asset accounting and does not use the shared service, therefore activity cost driver is called Gross Utility PlantxB (i.e., Gross Utility Plant excluding Brampton)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

Expert Evidence Statement from Black & Veatch Corporation

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the report 'Review of Common Corporate Costs (Distribution) – 2013' ("Report") dated September 19, 2013, prepared by Black & Veatch Corporation ("Black & Veatch").

Consultant:

Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

Black & Veatch, through its Management Consulting Division, provides strategic, economic and management consulting, specializing in energy matters, in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis.

Qualifications:

The lead experts on this project were:

Howard Gorman

Howard Gorman has 25 years of diversified experience in the energy industry and over 30 years of experience covering all areas of finance. He specializes in rate and regulatory matters, including electric and gas revenue of requirements, allocated cost of service and rate design; accounting and costing; energy project financing and analysis; energy asset valuations, acquisitions and divestitures; mergers and related management and organizational matters; economic and financial planning. Mr. Gorman has extensive experience in rate and regulatory matters for electric and gas utilities, including: Developing revenue requirements; Identifying customer class cross-subsidizations; Revenue allocation and rate design; Inter-affiliate cost allocation; and Budgeting and costing. He has testified before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy

Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman received a B.S. degree in Accounting from New York University (1976) and an M.B.A. from Harvard Business School (1981). He is a New York State licensed Certified Public Accountant.

Greg Van Dusen

Greg Van Dusen has spent over 30 years in the Electric Utility industry in Ontario, Canada and has had exposure to the U.S. utility industry and regulatory environment as well. Mr. Van Dusen was employed by Ontario Hydro for 20 years, with responsibility in the areas of fuel procurement, design and development, finance and regulatory. Ontario Hydro was Canada's largest integrated electricity utility, when it was separated into a transmission and distribution company (called Hydro One) and a generation company. Mr. Van Dusen joined Hydro One in 2000 and was involved in asset management, finance and regulatory areas until 2010, when he retired. He has been an expert witness at the Ontario Energy Board in rate applications for Hydro One in both Cost of Service and Incentive Regulation proceedings. In 2008 he assisted with the development of a case study on Hydro One for the Harvard Business School on Enterprise Risk Management. Mr. Van Dusen is currently on the Board of Directors of Ontario's largest electricity distribution system utility and is the Chair of the Finance, Regulatory and Policy Committee for this utility. He has detailed experience and expertise in; Regulatory Submissions, Regulatory Strategy and Witnessing, Cost of Capital, Risk Management, Business Planning, Internal Control and Asset Management practices and processes. Mr. Van Dusen has a BA Honours from York University, Toronto, Canada specializing in Mathematics, and an MBA from York University, Toronto, Canada specializing in Finance, Accounting and Information Management.

Instructions Provided:

The instructions provided to Black & Veatch in preparing the Report were:

Expert Evidence Statement from Black & Veatch Corporation

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate costs among the business units that use the functions and services. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Prepare a Report of the recommended Common Corporate Costs Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Identify the functions and services included in the Common Corporate costs.
- Identify activities that are performed in order to provide the functions and services included in the Common Corporate costs.
- Determine which Common Corporate functions can distribute cost directly, which units can have cost distributed using time studies and which units require allocations using drivers and why.
- Propose and analyze all drivers used for allocation.
- Propose, analyze and perform all time studies required.
- Distribute the annual budgeted costs for years 2014-2019 to perform each function and service among the activities required to perform it, based on time and/or cost studies.
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Cost Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- Prepare final reports for Common Corporate Costs allocation reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be submitted in Cost of Service applications.

Expert Evidence Statement from Black & Veatch Corporation

- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Basis of Evidence:

The basis for the evidence is set forth in the Section IV of the Report, *Review Application of Current Methodology to BP 2014-19* and Section V of the Report, *2013 Time Study*.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, B&V (formerly RJ Rudden and Associates) was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing Shared Services, between its Transmission and Distribution businesses and other businesses. B&V recommended the methodology, which was adopted by Hydro One and accepted by the Board in its EB-2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by B&V and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009-0096, EB-2010-0002 and EB-2012-0031. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:

Black & Veatch Corporation

Expert Evidence Statement from Black & Veatch Corporation

By Russell A. Feingold, Vice President, Management Consulting Division

Date:

January 10, 2014

OVERHEAD CAPITALIZATION RATE

This evidence discribes the methodology used to allocate Common Corporate Costs (which includes Corporate Functions and Services, Asset Management and Operators) to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its April 9, 2010 Decision on the Company's 2010 and 2011 Distribution rates (EB-2009-0096), the Board accepted the methodology, recommendations and the allocation of costs from a study by Black & Veatch (B&V) (formerly RJ Rudden Associates). This study had been commissioned to derive an overhead capitalization rate for Hydro One Distribution's Common Corporate Costs. The accepted methodology was also used in the the previous Distribution rate application EB-2007-0681 and the most recent Transmission rate application EB-2012-0031.

In 2013, the Company commissioned B&V to review and update its capital overhead methodology. The 2015-2019 overhead capitalization rates have been calculated consistent with the previously accepted B&V study methodology. The consistency in the use of this approach for the 2015-2019 test years has been reviewed by B&V in 2013, and is provided as Attachment 1 to this Exhibit.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate as calculated in the B&V study in 2013, continues to be a reasonable method of distributing Common Corporate Costs to capital projects. Hydro One's submissions in this Application reflect the overhead capitalization rate as developed.

Table 1 summarizes the overhead capitalization rates as reviewed by B&V.

Table 1
Overhead Capitalization Rate
(%)

Overhead Cost Category	**Test Years**				
	2015	**2016**	**2017**	**2018**	**2019**
Capitalized Administrative & General Costs	11%	10%	10%	11%	11%
Capitalized Operating Costs	3%	3%	3%	2%	2%
Total	14%	13%	13%	13%	13%

Table 2
Overhead Capitalized Amount
($ millions)

Overhead Cost Category	**Test Years**				
	2015	**2016**	**2017**	**2018**	**2019**
Capitalized Administrative & General Costs	69.5	65.4	64.4	67.1	69.7
Capitalized Operating Costs	16.4	16.0	15.9	15.3	15.6
Total	85.9	81.4	80.2	82.5	85.3

In its EB-2011-0399 decision, the Board granted Hydro One Disitrbution approval to adopt United States Generally Accepted Accounting Principles (US GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for rate setting, regulatory accounting and reporting. In its decision, the Board considered it appropriate to require Hydro One Disitrbution to conduct a review similar to the overhead capitalization review done for its transmission business.

"In its EB-2011-0268 decision, the Board directed Hydro One Transmission to conduct a critical review of its current and proposed capitalization practices. The review was not intended to be a benchmarking study per se, but it was intended to provide information with respect to what other US transmitters typically capitalize and the capitalization methodology that is employed by other transmitters. This information would be compared to Hydro One's capitalization policies." A summary of the results of this review, which covered both transmission and distribution entities, was filed as part of Hydro One Transmission's last cost of service rate application. The methodologies used to allocate Shared Services and Other O&M costs to the Transmission overhead capitalization rate was determined to be appropriate by the intervenors and Board Staff who participated in the Settlement Conference, and was acceptable by the Board in its Decision.

As documented in the review report, which is provided as Attachment 2 to this exhibit, Hydro One critically reviewed its cost capitalization policy with a particular focus on the capitalization of overhead and indirect costs. In its review, Hydro One found that its treatment of overheads capitalized is generally consistent with other major US and Canadian industry participants. The Company's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities. The Company also concluded that its overhead and indirect cost captilization methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent both with legacy Canadian and existing US GAAP. In addition, and perhaps more importantly, Hydro One's methodology is consistent with regulatory principles including the key goals of achieving intergenerational equity and avoiding cross subsidization.

REVIEW OF OVERHEAD CAPITALIZATION RATES (DISTRIBUTION)– 2015-2019

PREPARED FOR

Hydro One Networks Inc.

19 SEPTEMBER 2013

BLACK & VEATCH
Building a world of difference.

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List of Appendices

I. Overview

A. INTRODUCTION

Black & Veatch ("B&V" or "we") is pleased to provide this Report to Hydro One on our *Review of Overhead Capitalization Rates (Distribution)– 2015-2019*. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Distribution and Transmission capital expenditures; the results are the amounts of Common Corporate Costs that are capitalized to those capital expenditures for the year.

The methodology was developed for Hydro One by B&V, first presented in our report *Distribution Overhead Capitalization Rate Method* report dated May 20, 2005 and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology for development of the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW / ASSET VALUES	HYDRO ONE FILING	B&V REPORT
2006 Review	2006 Distribution Rates	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review	2008 Transmission Rates	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review (Distribution)	2010/2011 Distribution Rates	*Review of Overhead Capitalization Rates* dated June 29, 2009
2009 Review (Transmission)	2011/2012 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010
2011 Review (Transmission)	2013/2014 Transmission Rates	*Review of Overhead Capitalization Rates (Transmission)– 2013-2014* dated February 1, 2012

Hydro One computed the **Distribution OH Cap Rate to be 14% for 2015 and 13% for 2016-2019** (*Appendix A, row 90*). The calculation of the rates is described in Section II and shown in Appendix A.

Based on the work we performed, B&V believes that Hydro One's implementation of the Overhead Capitalization Rate methodology and computation of the Distribution OH Cap Rates for 2015-2019 are appropriate and conform to the OEB-accepted methodology.

B. BACKGROUND

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Distribution Capital spending is budgeted to be approximately $650M annually in 2015-2019, each year representing approximately 11% of Distribution Net utility plant.

Most of Hydro One's capital program is performed by Hydro One employees, and not contracted out. Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Distribution Operations and Maintenance ("Dx OMA") and Distribution Capital Expenditures work.

C. CRITERIA FOR COST ALLOCATION METHODS

The portion of Common Corporate Costs attributed to Distribution was determined based on the OEB-accepted methodology, as described in the B&V's *Review of Allocation of Common Corporate Costs (Distribution)*- 2013 dated September 19, 2013**.** The Distribution OH Cap Rate is used to distribute the Distribution portion of Common Corporate Costs, between Distribution OMA and Distribution Capital Expenditures. Following are the criteria that B&V used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on *cost causation*. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the costs that has been incurred.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is *benefits received* (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. DESCRIPTION OF OH CAP RATE METHOD

Ideally, the amount of Common Corporate Costs to be capitalized would be based entirely on time studies for labor costs, and additional analyses for other costs, for each activity include in Common Corporate Costs.

Approximately $115 million of labour costs (for the departments in the study), representing approximately 28% of the annual total Common Corporate Costs (and approximately 50% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-weeks ending May 31, 2013 ("2013 Time Study"). The 2013 Time Study included the following departments in the Operations group: Distribution Business Development; Transmission Projects Development; Asset Strategy; Network Operations; Transmission Asset Management; and SVP Planning & Operating; and the following departments in the Customer Service group: Customer Care Services; Strategy and Conservation; Distributed Generation; Customer Business Relations; TxDx Settlements; Account Management Director; Advanced Distribution; Pricing; VP Customer Service; SVP Customer Operations.

A properly performed time study measures cost causation, and is widely accepted as a basis for allocating costs. B&V participated in the design, administration and supervision of the 2013 Time Study. The methodology was the same as for prior time studies conducted by B&V for Hydro One. B&V found that the 2013 Time Study was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized to Distribution capital expenditures.

While the remaining Common Corporate Costs departments can determine with reasonable accuracy the portions of time spent on Distribution, Transmission and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects. Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. B&V considered the following two bases for allocating Common Corporate Costs costs between OMA and capital projects:

- **Labor Content Method-** Labor Content of Distribution (Dx) OMA versus Dx capital expenditures
- **Total Spending Method-** Total Spending on Dx OMA versus Dx capital expenditures

The Common Corporate Costs to be allocated are causally related to both Labor content and Total spending. Therefore the OH Cap Rate method for Common Corporate Costs recommended by B&V uses a weighting of 50% Labor Content and 50% Total Spending, as there is no evidence that either the Labor Content method or the Total Spending method is meaningfully more appropriate.

- The formula for Distribution (Dx) Labor Content is:

Dx Labor Content = Dx Labor $ in Dx Capital Expenditures / (Labor $ in Dx Capital Expenditures + Labor $ in Dx OMA)

- The formula for Dx Total Spending is:

Dx Total Spending = Dx Capital Expenditures / (Dx Capital Expenditures + Dx OMA)

The table below shows the results of the computations for 2015-2109.

PORTION OF COMMON CORPORATE COSTS SERVICES CAPITALIZED- DISTRIBUTION	2015	2016	2017	2018	2019
Labor Content- Capital	54.1%	50.5%	50.4%	51.6%	52.9%
Total Spending- Capital	59.7%	57.6%	56.8%	57.9%	58.9%
50/50 Average	56.9%	54.1%	53.6%	54.8%	55.9%

Sensitivity Analysis

As a sensitivity analysis, B&V analyzed two sensitivity cases- the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

CASES	LABOR CONTENT / TOTAL SPENDING	DISTRIBUTION-2015		DISTRIBUTION -2016	
		% costs Capitalized	2015 OH Cap Rate	% costs Capitalized	2016 OH Cap Rate
Recommended	50%/50%	56.9%	13.8%	54.1%	12.9%
High Labor Case	75%/25%	55.5%	13.6%	52.3%	12.6%
Low Labor Case	25%/75%	58.3%	14.1%	55.8%	13.3%

Note- In all cases Dx Labor Content-Capital and Dx Total Spending-Capital were the ratios in the table above.

B&V also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of Common Corporate Costs services. For example, a transformer that is purchased for use in a capital project from a pre-approved vendor requires very little of these services, but receives the same rate of overhead capitalization as a project requiring substantial support. In applying the OH Cap Rates, there will be differences compared to performing a specific analysis for each project. However, the B&V method is appropriate because:

- B&V's recommended Labor / Total Content method correctly computes the total Common Corporate Costs dollars to be capitalized, and the amount charged to specific expenditures has virtually no effect on the financial statements or on ratepayers.
- Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to them. Other assets (i.e., non- Minor Fixed Assets) are usually parts of larger projects, therefore the use of average OH Cap Rates is appropriate, because larger expenditures are more likely to have an average usage of Shared Services.
- It is impractical to perform an analysis for each project.

2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. B&V recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content.

B&V believes that allocating Common Corporate Costs to capital expenditures based on 50% Labor Content / 50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the costs being capitalized.

E. USE OF BUDGETED NUMBERS

The OH Cap Rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the OH Cap Rates quarterly to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustment is needed in subsequent years.

II. Computation of Distribution OH Cap Rate

This Section presents, as an example, the computation of the Distribution OH Cap Rate for 2015. The calculation of the rate uses the same method for all years in BP 2015-2019.

A. FORMULA

The following formula is used to compute the 2015-2019 Distribution OH Cap Rates:

a. *Distribution OH Cap Rate*= (Capitalized Distribution CCC-A&G Costs + Capitalized Distribution CCC-Operating Costs) / Distribution Capital Expenditures

Note: A&G = Administrative & General

Where

b. *Capitalized Distribution CCC-A&G Costs* = Distribution CCC-A&G Costs capitalized = (Distribution Labor Content Ratio X 50% + Distribution Total Spending Ratio X 50%) X Distribution CCC-A&G Costs

c. *Distribution CCC-A&G Costs* = Total Distribution CCC Costs less Distribution CCC-Operating Costs departments

d. *Capitalized Distribution CCC-Operating Costs* = Distribution CCC-Operating Costs capitalized, based on the results of the 2013 Time Study

e. *Distribution CCC-Operating Costs* = The budgets for the following departments, included in the 2013 Time Study:

- Asset Development and Management, comprising the following departments in the Operations group: Distribution Business Development; Transmission Projects Development; Asset Strategy; Transmission Asset Management; and SVP Planning & Operating, plus
- Network Operating department (part of the Operations group), plus
- Customer Care, comprising the following departments in the Customer Care group: Care Services; Strategy and Conservation; Distributed Generation; Customer Business Relations; TxDx Settlements; Account Management Director; Advanced Distribution; Pricing; VP Customer Service; SVP Customer Operations).

f. *Distribution Capital* = Cost of Distribution capital expenditures supported by Common Corporate Costs (i.e., CCC-A&G Costs plus CCC-Operating Costs); also, total cost of Distribution capital expenditures to which the Distribution OH Cap Rate is applied

g. *Distribution Labor Content Ratio* = Distribution Labor $ in Distribution Capital Expenditures / (Labor $ in Distribution Capital Expenditures + Labor $ in Distribution OMA)

h. *Distribution Total Spending Ratio* = Distribution Capital Expenditures / (Distribution Capital Expenditures + Distribution OMA)

These terms are further discussed below.

B. RECOMMENDED METHOD

This section discusses the method recommended by B&V to compute the Distribution OH Cap Rate. References below are to Appendix A, and the amounts and percentages cited are for 2015. The calculations use projected data. Because the methodology includes a true-up at the end of the year (Section I.E), the amounts recorded by Hydro One reflect actual data.

1. DISTRIBUTION CAPITAL

(Appendix A, rows 1-8)

Distribution Capital (Formula f in Section II.A) represents the cost of Distribution business Capital Expenditures that are supported by Distribution business CCC activities (CCC-A&G activities and CCC-Operating activities), and is the total cost of Distribution business Capital Expenditures to which the Distribution OH Cap Rate is applied. Distribution Capital equals total spending for Distribution Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCC-A&G or CCC-Operating support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the CCC-A&G and CCC-Operating effort required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires support from CCC-A&G and CCC-Operating.

2. DISTRIBUTION SPENDING FOR OMA

(Appendix A, rows 10-16)

Distribution Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 42-46). The amounts are based on the BP 2015-2019, with adjustments to remove those costs which are included in Applicable CCC-A&G costs (row 34).

3. APPLICABLE DISTRIBUTION CCC-A&G COSTS

(Appendix A, rows 18-34)

Applicable Distribution CCC-A&G Costs (Formula c) (row 34) represents the Distribution CCC-A&G Costs subject to capitalization, and equals total Common Corporate Costs distributed to the Distribution Business in the Common Corporate Costs Model, adjusted as follows:

- Distribution CCC-Operating Costs (Formula e) are removed because the capitalization ratios for those departments were determined in the 2013 Time Study.
- Distribution Facilities costs that are removed from the CCC-A&G Costs, relating to Operations facilities, are added back, because they are used to support activities that support Capital Expenditures.
- Distribution CCC-A&G Costs for the following departments that do not support capital expenditures are removed: Inergi- Customer Support Operations (CSO), Inergi-ETS to support CSO Applications, Inergi-ETS to support market transition costs and Inergi- Settlements.

4. DISTRIBUTION LABOR CONTENT- CAPITAL RATIO

(Appendix A, rows 36-40)

Distribution Labor Content-Capital Ratio is the portion of total Distribution labor costs included in Distribution Capital Expenditures (Formula g). The Labor $ on Rows 37-38 were developed by Hydro One. The Labor $ are fully burdened labor costs (salary plus benefits).

5. DISTRIBUTION TOTAL SPENDING- CAPITAL RATIO

(Appendix A, rows 37-41)

Distribution Total Spending-Capital Ratio is the portion of Distribution total spending included in Distribution Capital Expenditures (Formula h). In the formula, Distribution spending for OMA (row 43) is from row 16 and Distribution spending for capital expenditures (row 44) is from row 8.

6. CAPITALIZED DISTRIBUTION CCC-A&G

Capitalized CCC-A&G Costs (Formula b) is the portion of Distribution CCC-A&G Costs to be capitalized. The portion of Distribution CCC-A&G Costs to be capitalized (row 52) is the average of Distribution Labor Content-Capital Ratio (from row 40) and Total Spending Capital Ratio (from row 46), using the appropriate weights (rows 49-50),. This portion is multiplied by the Applicable CCC-A&G Costs (row 34) to compute Capitalized CCC-A&G Costs (row 54).

7. CAPITALIZED DISTRIBUTION CCC-OPERATING

(Appendix A, rows 56-83)

Capitalized Distribution CCC-Operating Costs (Formula d) represents the amount of Distribution CCC- Operating Costs capitalized to Distribution Capital Expenditures. The 2013 Time Study showed that 20.8% of Asset Development and Management time, 8.1% of Network Operations time and 2.9% of Customer Care time, are related to Distribution Capital Expenditures. These percentages are applied to the BP 2015-2019 annual budgeted amounts for those groups, and the results are the amounts of CCC-Operating Costs to be capitalized (rows 73-77).

8. DISTRIBUTION OH CAP RATE

(Appendix A, rows 85-90)

The Distribution OH Cap Rate (Formula a) equals A) the sum of items 6and 7 above, divided by B) Capital spending. The Distribution OH Cap Rate for 2015-2019 (row 90) are in the table below.

DISTRIBUTION OVERHEAD CAPITALIZATION RATE	2015	2016	2017	2018	2019
Rate	14.0%	13.0%	13.0%	13.0%	13.0%

Review of Overhead Capitalization Rates (Distributoin)- 2015-2019

		DISTRIBUTION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2015**	**2016**	**2017**	**2018**	**2019**
1	**Capital Expenditures**					
2	Total capital expenditures	648.9	654.7	639.4	655.1	669.1
3	Less: Minor fixed assets	(54.2)	(58.6)	(53.6)	(56.2)	(53.2)
4	Less: Capitalized overhead	(85.9)	(81.4)	(80.2)	(82.5)	(85.3)
5	Less: Capitalized interest	(16.8)	(19.6)	(22.6)	(21.5)	(21.5)
6	Add: Capital contributions	73.8	77.8	69.0	67.2	68.6
7	Add: Removal costs	54.5	57.0	60.4	63.3	65.8
8		620.4	629.9	612.4	625.5	643.5
9						
10	**OM&A**					
11	Total OM&A	564.3	610.2	614.0	603.9	600.0
12	Less: CCC-A&G Costs	(149.4)	(148.2)	(147.7)	(151.2)	(154.0)
13	Less: Facility costs	(22.5)	(22.4)	(22.9)	(23.4)	(24.4)
14	Less: CCC-Operating Costs	(58.7)	(57.6)	(57.5)	(57.5)	(58.4)
15	Add: Capitalized overheads	85.9	81.4	80.2	82.5	85.3
16		419.5	463.4	466.0	454.2	448.5
17						
18	**Capitalized CCC-A&G Costs**					
19	Total CCC per Model	208.1	205.8	205.3	208.7	212.4
20	Less: ADM	(18.4)	(17.8)	(17.6)	(17.5)	(17.8)
21	Less: Network Operator	(16.3)	(16.5)	(16.6)	(16.8)	(17.1)
22	Less: Customer Care	(23.2)	(22.5)	(22.6)	(22.3)	(22.6)
23	Less: CBR	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
24	CCC-A&G Costs	149.4	148.2	147.7	151.2	154.0
25	Add: Facility costs	22.5	22.4	22.9	23.4	24.4
26						
27	Less operating-type costs in CCC-A&G Costs					
28	Inergi - CSO	(34.1)	(34.1)	(35.1)	(36.1)	(37.2)
29	Inergi - ETS CSO Apps	(7.6)	(7.4)	(7.2)	(7.4)	(7.6)
30	Inergi - ETS Market Ready	(4.1)	(4.0)	(3.9)	(4.0)	(4.1)
31	Inergi - Settlements	(3.9)	(4.2)	(4.4)	(4.6)	(4.8)
32		(49.8)	(49.6)	(50.6)	(52.1)	(53.8)
33						
34	Applicable CCC-A&G Costs	122.2	120.9	120.1	122.6	124.7
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	298.3	340.6	343.3	333.5	328.3
38	Labour in capital expenditures	352.0	347.8	349.0	355.7	369.4
39		650.3	688.4	692.4	689.2	697.7
40	Labor Content- Capital Ratio	54.1%	50.5%	50.4%	51.6%	52.9%
41						
42	Portion capitalized based on total spending:					
43	OM&A	419.5	463.4	466.0	454.2	448.5
44	Capital expenditures	620.4	629.9	612.4	625.5	643.5
45		1,039.9	1,093.3	1,078.4	1,079.6	1,092.0
46	Total Spending- Capital Ratio	59.7%	57.6%	56.8%	57.9%	58.9%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	56.9%	54.1%	53.6%	54.8%	55.9%
53						
54	Capitalized CCC-A&G costs	69.5	65.4	64.4	67.1	69.7

	($ millions)	DISTRIBUTION OVERHEAD CAPITALIZATION RATES 2015	2016	2017	2018	2019
55						
56	**Capitalized CCC-Operating Costs**					
57	Total CCC-Operating Costs					
58	Asset Develop & Management	55.5	53.5	52.7	52.2	53.1
59	Network Operating	48.5	49.0	49.2	50.0	50.7
60	Customer Care	29.7	29.0	29.1	28.9	29.4
61		133.7	131.5	130.9	131.1	133.2
62						
63	Portion capitalized (per time study):					
64	Asset Develop & Management	20.8%	20.8%	20.9%	21.0%	21.1%
65	Network Operating	8.1%	8.1%	8.1%	8.1%	8.1%
66	Customer Care	2.9%	3.0%	3.0%	1.0%	1.0%
67						
68	Portion to OMA (per time study):					
69	Asset Develop & Management	12.3%	12.4%	12.5%	12.5%	12.6%
70	Network Operating	25.6%	25.6%	25.6%	25.6%	25.6%
71	Customer Care	78.0%	77.5%	77.5%	79.0%	79.0%
72						
73	Capitalized CCC-Operating Costs					
74	Asset Develop & Management	11.5	11.1	11.0	11.0	11.2
75	Network Operating	3.9	4.0	4.0	4.1	4.1
76	Customer Care	0.9	0.9	0.9	0.3	0.3
77		16.4	16.0	15.9	15.3	15.6
78						
79	Non-capitalized CCC-Operating Costs					
80	Asset Develop & Management	6.8	6.6	6.6	6.6	6.7
81	Network Operating	12.4	12.5	12.6	12.8	13.0
82	Customer Care	23.2	22.4	22.5	22.9	23.2
83		42.4	41.6	41.7	42.2	42.8
84						
85	**Overhead Capitalization Rate**					
86	Capitalized CCC-A&G Costs	69.5	65.4	64.4	67.1	69.7
87	Capitalized CCC-Operating Costs	16.4	16.0	15.9	15.3	15.6
88	**TOTAL COMMON CORPORATE COSTS CAPITALIZED**	85.9	81.4	80.2	82.5	85.3
89						
90	**Overhead capitalization rate**	**14.0%**	**13.0%**	**13.0%**	**13.0%**	**13.0%**

Expert Evidence Statement from Black & Veatch Corporation

This Statement is provided in compliance with Ontario Energy Board ("Board) Rule 13A, regarding the report 'Review of Overhead Capitalization Rates (Distribution) – 2015-2019' ("Report") dated September 19, 2013, prepared by Black & Veatch Corporation ("Black & Veatch").

Consultant:

Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

Black & Veatch, through its Management Consulting Division, provides strategic, economic and management consulting, specializing in energy matters, in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis.

Qualifications:

The lead expert on this project was:

Howard Gorman

Howard Gorman has 25 years of diversified experience in the energy industry and over 30 years of experience covering all areas of finance. He specializes in rate and regulatory matters, including electric and gas revenue of requirements, allocated cost of service and rate design; accounting and costing; energy project financing and analysis; energy asset valuations, acquisitions and divestitures; mergers and related management and organizational matters; economic and financial planning. Mr. Gorman has extensive experience in rate and regulatory matters for electric and gas utilities, including: Developing revenue requirements; Identifying customer class cross-subsidizations; Revenue allocation and rate design; Inter-affiliate cost allocation; and Budgeting and costing. He has testified before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy

Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman received a B.S. degree in Accounting from New York University (1976) and an M.B.A. from Harvard Business School (1981). He is a New York State licensed Certified Public Accountant.

Instructions Provided:

The instructions provided to Black & Veatch in preparing the Report were:

- Recommend a best practice methodology to distribute an appropriate amount of Hydro One Inc.'s Common Corporate costs to Capital Expenditures through the overhead capitalization rate. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology or elimination entirely of an overhead capitalization methodology.
- Prepare a Report of the recommended Overhead Capitalization Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Identify the functions and services included in the Common Corporate costs.
- Identify activities that are performed in order to provide the functions and services included in the Common Corporate costs.
- Propose, analyze and perform all time studies required. Prepare a report documenting the overhead capitalization methodology that has been developed which will attribute Common Corporate costs to capital expenditures for both the Distribution and Transmission businesses for each year 2015-2019.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Overhead Capitalization Methodology.
- Be available to testify to the proposed methodology during a future rate application.

Expert Evidence Statement from Black & Veatch Corporation

- Final reports for Overhead Capitalization Methodology reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be submitted in Cost of Service applications.
- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Basis of Evidence:

The basis for the evidence is set forth in the Section ID of the Report, *Description of OH Cap Rate Method*, and Section IIB of the Report, *Recommended Method*.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, B&V (formerly RJ Rudden and Associates) was engaged by Hydro One to develop a methodology for Hydro One to allocate a portion of its Shared Services costs through the overhead capitalization rate. B&V recommended a methodology which was adopted by Hydro One and accepted by the Board in its EB-2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by B&V and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009-0096, EB-2010-0002 and EB-2012-0031. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:

Expert Evidence Statement from Black & Veatch Corporation

Black & Veatch Corporation

By Russell A. Feingold, Vice President, Management Consulting Division

Date:

January 10, 2014

Hydro One Networks Inc.

Distribution Business –
Review of Overhead Capitalization Policy

April 14, 2012

Executive Summary

In its EB-2011-0268 and EB-2011-0399 decisions, the Ontario Energy Board (OEB or Board) granted Hydro One Networks Inc. (Hydro One, Networks or the Company) approval to adopt United States (US) generally accepted accounting principles (GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for regulatory accounting and reporting.

In its decisions, the Board considered it appropriate to require Networks "to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

The following report has been developed to document the results of Hydro One's review of the appropriateness of its capitalization accounting policy for overhead and indirect costs. The Company's review incorporated a study of accounting theory under the various GAAP frameworks, a review of regulatory guidance in North America and a comparison between Hydro One's practices and those of other North American utilities.

The study approach incorporated the following steps:

1. A review of Hydro One's legacy accounting policy and the rationale for it;
2. A review of the GAAP environment governing overhead/indirect cost capitalization;
3. A review of North American regulatory principles and related guidance;
4. An assessment of the of Hydro One's approach in light of steps 2 and 3 above;
5. Conducting industry research; and
6. Conclusion

Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in the Company's industry research of other Canadian and US utilities.

This information is summarized in the following table.

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) - 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

In addition to the rate findings, industry research clearly shows that the capitalization of general and administrative overhead costs is accepted practice.

The key findings of the Company's policy review were:

1. In prior years, Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied, rational and systematic model based on causality. No changes in Hydro One's methodology are proposed with the adoption of US GAAP.

2. Legacy Canadian and US GAAP both allow for the capitalization of attributable indirect costs and overheads, while IFRS specifically prohibits the capitalization of several categories of such expenditures.

3. Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable overheads based on a cost causality model.

4. Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures, consistent with GAAP and regulatory guidance.

5. Hydro One's practice, both in terms of the types and proportion of overhead and indirect expenditures capitalized, is generally consistent with the practices of many other large North American transmitters and other rate regulated utilities.

6. Hydro One's cost capitalization policy with respect to overheads and indirect costs is an appropriate one for use in a US GAAP regulatory environment.

Introduction - Overview of the Study

In its EB-2011-0268 and EB-2011-0399 decisions, the Board granted Networks approval to adopt US GAAP instead of modified IFRS for regulatory accounting and reporting purposes. The OEB generally accepted Hydro One's position that adopting US GAAP would result in benefits both to its customers and to its shareholder. In addition, in response to intervenor assertions that Hydro One's capitalization practices had been "aggressive" under legacy Canadian GAAP, the OEB also considered "it appropriate to require Hydro One to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

In its decision with reasons on EB-2011-0268, the OEB noted that the reduction in revenue requirement, and intervenor support for it, was a significant argument in favour of retaining the Company's legacy cost capitalization policy for Networks' Transmission Business. Hydro One's cost capitalization policy was developed under legacy Canadian GAAP, where it has been subjected to external audit since inception of the company. The Company believes that It continues to be an appropriate policy under US GAAP. Such a policy was not allowable under the constraining cost capitalization rules found within IFRS, most particularly in IAS 16 "Property, Plant and Equipment."

Specifically, significant differences in accounting exist between US and legacy Canadian GAAP on one side, and IFRS on the other, with respect to the indirect and general and administrative overhead expenditures that qualify for capitalization. A measure of the magnitude of the revenue requirement impact of the different accounting frameworks can be seen in the $200 million adjustment required to reflect the Board's EB-2011-0268 Transmission decision that authorized the Company's use of US GAAP for regulatory purposes.

In response to the Board's direction, Hydro One has performed a critical review of the theoretical appropriateness of its accounting policies governing the capitalization of overhead and indirect costs. This review focused on: a review of the conformance of its legacy Canadian and continuing US GAAP capitalization policy with GAAP; consistency with regulatory principles and guidance; and a comparison with the practices of other major US and Canadian utilities. These comparable utilities include both transmitters and large distributors, including some within Ontario. The latter were included as it was determined early on in the study that the Board would likely require an extension of the scope of the transmission analysis to distributors given that Networks had also requested an exception to adopt US GAAP for its Distribution Business as well. On March 23, 2012, the Board approved Networks' request in respect of its Distribution Business (EB-2011-0399) as well. A similar request was made in that decision to conduct a Distribution Business cost capitalization study. However, given the requirement to compare to other Ontario local distribution companies that are using modified IFRS as a basis for their external reporting and rate setting, the scope of that report is likely to be somewhat different than this one.

The Company determined that it was appropriate to extend of the scope of its research to include large Canadian distributors as finding detailed information on US practice was quite difficult. Inclusion of other Canadian entities expands the pool of comparable utilities. In addition, a recent surge in the numbers of Canadian utilities seeking approval to adopt US GAAP in place of IFRS has led to increased informal information sharing and greater availability of information in Canada.

The critical review requested by the Board has been conducted in two main parts. The first part was a review of the origin and continued appropriateness of Hydro One's cost capitalization accounting policies under GAAP and under regulatory principles and guidance. The second element of the study was a comparison to the practices of other major North American rate regulated utilities. As noted in the Board's request, this was not intended to be a comprehensive benchmarking study. Instead, it was treated as an intelligence gathering activity aimed at gathering useful information on what types and amounts of indirect and overhead costs other utilities capitalize.

The general approach adopted to fulfill the Board's request is described below:

1. Review Hydro One's Legacy Accounting

Hydro One's existing cost capitalization policies and the underlying rationale for them were evaluated and are summarized herein.

2. Summarize GAAP

The indirect and overhead cost capitalization requirements of competing GAAP frameworks were evaluated and are summarized herein.

3. Summarize Regulatory Guidance

Specific regulatory guidance was gathered and summarized and underlying regulatory principles governing cost capitalization were identified and are discussed herein.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Hydro One assessed the degree of conformity between its cost capitalization practices and the requirements of GAAP and objectives of regulatory principles.

5. Conduct Industry Research

Hydro One gathered information on the overhead capitalization practices of selected major North American utilities. The objective of this research was to determine to what extent Hydro One's indirect cost and overhead capitalization approach conforms to generally accepted utilities practice and to what extent it can be deemed "aggressive" compared to its peers.

6. Conclusion

Hydro One reviewed the conclusions from step 4 above and the comparable information from step 5 to conclude on the reasonableness of continuing to apply its legacy Canadian GAAP approach to its US GAAP rate setting.

1. Review Hydro One's Legacy Accounting

Key findings: Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied rational and systematic cost causality model.

Hydro One has two primary accounting policies that govern the capitalization of expenditures for each of its legal subsidiaries and regulated businesses. The policy that governs the classification of expenditures between capital and operation, maintenance and administration (OM&A) is SP 0775 R0 "Classification of Expenditures." This policy has not been significantly adjusted since demerger from Ontario Hydro in 1999 and the guidance included within it has been applied consistently in determining the rate base and revenue requirement for each of Hydro One's regulated subsidiaries and businesses. The policy has also been consistently reflected in developing Hydro One Transmission's audited financial statements.

The second applicable policy is SP 0804 R0 "Shared Corporate Services Cost Allocation and Transfer Pricing Policy," which outlines the principles to be used in allocating shared corporate functions and services costs. This policy provides guidance on the allocation of shared services costs, requiring that they be assigned to affiliates based on the principle of cost-causation.

General capitalization approach

Hydro One provides detailed policy guidance on whether expenditures incurred in a given accounting period should be recorded in the Statement of Operations as an expense of that period, or included as an asset on the Balance Sheet. For regulatory purposes, the consequence of this decision is either inclusion in current period revenue requirement or in the rate base. The overriding criteria applied in determining the appropriate accounting treatment of an expenditure is whether or not it meets the definition of an asset under GAAP. In almost all cases, the regulatory treatment parallels the GAAP classification.

To determine whether an expenditure represents and an expense of the period or an asset with future economic benefit, the GAAP principle of "matching" is applied. The definition of an asset under US GAAP is found in Financial Accounting Standards Board (FASB) Statement of Financial Accounting Concepts (SFAS) No. 6 "Elements of Financial Statements." Under this concepts standard, an asset consists of "probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events." In addition, "an asset has three essential characteristics: (a) it embodies a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows, (b) a particular entity can obtain the benefit and control others' access to it, and (c) the transaction or other event giving rise to the entity's right to or control of the benefit has already occurred." This definition is virtually identical to that found in the parallel accounting standard in legacy Canadian GAAP. This is found in section 1000 "Financial Statement Concepts" in Part V of the Handbook of the Canadian Institute of Chartered Accountants.

Asset recognition of those expenditures that will probably result in future economic benefits is a foundational concept in accrual accounting. Accrual accounting requires that the relationship between an expense and a revenue item be evaluated and, where there is a direct relationship, that the timing of expense recognition be matched to the recognition of that future related revenue. This assessment requires that the strength and nature of the relationship between expenditures and resultant future benefits be evaluated. This is accomplished by using professional judgment to determine whether a causality and/or beneficial relationship exists between them. In a rate regulated environment, any assessment of future benefits resulting from expenditures will also include in an assessment of whether the expenditure provides operational or service benefits to future customers. This also requires some assessment of whether the expenditure is caused by, or benefits future customer generations.

Hydro One's Classification of Expenditures Policy

Hydro One's Classification of Expenditures Policy is one of the company's most important and often referenced accounting policies. In general, it provides general and specific guidance on the types of expenditures that qualify as assets, defines capitalization terms, provides dollar capitalization thresholds for projects and provides specific decision rules for certain types of transactions.

Under the policy, expenditures incurred for the following general purposes are eligible for capitalization, when above established materiality limits:

- purchase, construction and commissioning of specific assets;
- design and development of specific assets;
- additions of new or replacement components for existing assets; and
- betterments that result in increases in: productive capacity or output; efficiency; useful life span over original specification; or economy of operation.

The Classification of Expenditures Policy requires that the following types of expenditures qualify for capitalization: direct labour; direct materials and supplies; transportation costs; directly attributable external costs; fees; permits; indirect expenditures (including financing costs and attributable shared functions and services costs including general engineering, administrative salaries and expenses), and attributable indirect depreciation of equipment, tools and transport and work equipment.

While the policy does not specifically determine which overhead and indirect costs may be capitalized, it does provide the overall framework for the definition of an asset.

Hydro One's Shared Corporate Services Cost Allocation and Transfer Pricing Policy

This policy governs the allocation of shared asset and corporate functions and services costs between Hydro One's various subsidiaries and regulated businesses. For Networks, the policy also governs the allocation of shared asset management costs between the Transmission and Distribution businesses. The policy is important to ensure that the risk of cross subsidization between regulated and unregulated entities, and between different regulated businesses, is minimized. The policy also provides guidance on the acceptable basis of transfer pricing between entities, essentially reflecting the guidance found within the Board's Affiliate Relationships Code.

Shared corporate services include the provision of shared strategic management, policy and functional support to the subsidiaries and businesses of the parent entity. The rationale for sharing such costs is that it is economically more efficient to locate them centrally and share them based on causality and benefit than to replicate them within each affiliate. Shared costs relate to the provision of such shared services as: legal;

regulatory; procurement; building and real estate support; information management and technology; corporate administration, finance, tax, treasury, pension, risk management, audit, planning, human resources, health and safety, communications, investor relations, trustee, and public affairs.

The same causality and benefit principles that are used to drive the allocation of shared corporate support expenditures and shared asset costs are also used to determine the appropriate classification of indirect and overhead expenditures between capital and OM&A.

The corporate cost allocation methodology requires that expenditures that can reasonably be specifically identified with a specific affiliate (i.e. subsidiary or regulated business) be allocated to that affiliate on a direct cost basis. However, most shared corporate functions and services costs cannot be directly associated with a specific affiliate and are therefore not treated as a direct charge. Shared corporate services costs that are not directly attributed must be allocated to the receiving affiliate using a rational and systematic mechanism. In general, cost drivers are used to achieve this goal. The driver to be used in allocating each shared cost should be the most appropriate based on the principle of cost causality. Causality exists when the incurrence of the shared cost is due to the business requirements of the affiliate. The Company must evaluate whether the cost would have been incurred had the affiliate’s requirements not caused it? In cases where a causal relationship cannot be identified, but where the affiliate benefits from the shared service, a cost driver is selected that instead reflects the principle of cost benefit. In this case, the objective is to determine the proportion of total benefits provided by the shared service is enjoyed by the affiliate. Where a shared staff time study is deemed to be the most appropriate cost driver, such a time study is periodically updated to provide relevant information and evidence of causality and benefit.

Hydro One’s methodology is reviewed internally on an annual basis and is independently reviewed periodically by an expert consultant for continued appropriateness of assumptions such as drivers. A full description of the cost allocation methodology as reviewed by Black and Veatch can be found in their report. Specific cost drivers and allocation rates are updated by Hydro One on an annual basis. All changes in direct and indirect costs, the allocation methodology, or cost drivers/allocators are appropriately documented.

Accurate allocation is necessary to ensure that, to the extent possible, customers of specific regulated utilities are paying for the cost of providing that utility’s service. In addition, accurate and principle-based allocation ensures that the risk of cross subsidization between regulated and unregulated affiliates is minimized. Use of fully-allocated cost-based pricing ensures that inter-affiliate transfers comply with both the letter and the spirit of the Board’s Affiliate Relationships Code. This code requires that affiliate transfers generally occur at fair value or, where such a value cannot reasonably be ascertained, at fully allocated cost taken as a proxy for fair value. Under Hydro One’s accounting policy for cost allocation and transfer pricing, the inter-affiliate transfer of shared corporate services occurs at a fully allocated transfer price that retains the fair value proxy concept. This is because it incorporates the same general cost components that would be charged by an external service provider or vendor.

Summary of Hydro One’s Overhead Capitalization Methodology

Hydro One uses the same general methodology and principles that it uses to allocate shared costs to affiliate entities when it classifies expenditures between current period expense and capital. The rationale for this is that the principles of causality and benefit are equally relevant for developing a robust and defensible assignment of cost responsibility between current and future customer generation. The objective of avoiding cross subsidization is the same as faced in allocating costs between entities. However, in the case of accounting classification the issue is avoiding having different generations (i.e. years) of customers cross subsidize each other. Customers should generally pay the costs that they cause or receive benefits from. Hydro One's accounting policies and practices have aimed at maintaining this objective to the extent possible while still adhering to the requirements of GAAP.

Hydro One's overhead capitalization methodology, similar to its allocation methodology, is subject to periodic external review by an independent consultant (currently Black and Veatch). The overhead capitalization methodology currently proposed for use by Hydro One Transmission develops separate capitalization rates within each affiliate, after shared costs have been fully allocated. To ensure that only those costs that benefit future customer generations get capitalized as part of the acquisition cost of fixed and intangible assets, Hydro One's methodology first screens allocated costs for whether or not they contribute to such assets. Certain expenditure types that are clearly not causally or beneficially linked to the acquisition of assets are removed from the overhead capitalization pool and disqualified from potential capitalization. This occurs as a first step in developing the capitalization rate. Secondly, if allocated shared costs can be associated with capital programs or projects, such costs are directly assigned to the pool of capitalizable expenditures even if they are not directly charged. Thirdly, a causality and benefit-based model is used to develop the capitalization rate. This rate is revisited through the year and adjusted as required to ensure that in-year variances are trued-up appropriately as underlying factors change.

Hydro One's methodology is based on the following principles:

- Regulatory Precedent – The shared service allocation methodology was initially developed with the assistance of Black and Veatch (then Rudden Associates) and was first documented in their 2005 "Report on Common Corporate Costs Methodology Review," which was accepted by the Board. Prior to the introduction of this independent review, Hydro One had carried out its own causality-based overhead allocation for its transitional rate orders for 1999 and 2000 rate years. The Black and Veatch report explicitly shows that the allocation and capitalization methodologies in use are based on cost causality and benefit principles. The current cost allocation methodology is consistent with that sued in prior years under legacy Canadian GAAP and is appropriate for use in a US GAAP environment. The use of direct assignments and cost drivers conforms to best practice.

- Cost Causation - The allocation methodology is reflective of the cost required to provide the shared services to affiliates. Shared service costs are allocated to each affiliate based on direct assignment where possible or based on activity cost drivers or time studies when not. The use of cost drivers conforms with the principle of direct attribution found in GAAP, as well as the regulatory principle of intergenerational equity.

- Supportive Methodology - The approach is supported by a defined and documented methodology that is subject to constant update. In addition, the approach is reviewed by, and reported on by an independent external consultant (Black and Veatch) on a recurring basis. In general, Black and Veatch reviews and reports on Hydro One's methodology in advance of major cost of service rate applications. Cost allocations and capitalization rates are updated annually by Hydro One as part of the business planning process. The current methodology is well understood by the subsidiaries and business units to which costs are distributed as well as estimators and project managers who are accountable for determining the cost of capital projects and programs. In addition, the current methodology is integrated with Hydro One's annual business planning process, thus producing reasonable and stable results over time.

2. Summarize GAAP

Key findings: Legacy Canadian and US GAAP both allow for the capitalization of attributable overheads while IFRS provide specific prohibitions that restrict the capitalization of several categories of such expenditures.

To evaluate the appropriateness of Hydro One's cost capitalization policy for indirect and overhead costs, it is useful to review the specific guidance found in the applicable accounting standards under each of the three relevant accounting frameworks: legacy Canadian GAAP; US GAAP and IFRS. More specifically, these are:

1. Legacy Canadian GAAP as defined by Part V of the Handbook of the Canadian Institute of Chartered Accountants;
2. US GAAP as defined by the Accounting Standards Codification (ASC) of the FASB; and
3. Current Canadian GAAP or IFRS as defined by Part I of the Handbook of the Canadian Institute of Chartered Accountants (CICA).

With respect to overhead accounting, it is necessary to understand that the concept of developing and applying overhead rates is a management accounting tool rather than a financial accounting activity. As a result, there is very limited explicit guidance in the financial accounting pronouncements of the three major accounting bodies.

1. Legacy Canadian GAAP

<u>Financial Accounting</u>

Guidance on the capitalization of expenditures under legacy Canadian GAAP is primarily found in section 3061 "Property, Plant and Equipment." Section 3061.16 indicates that property plant and equipment assets should be recorded at cost and provides guidance on the types of costs that qualify for capitalization. Section 3061.05 states that the cost of asset is " the amount of consideration given up to acquire, construct, develop or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset."

A major difference between section 3061 and the comparable IFRS standard (discussed in further detail below), is that the Canadian standard does not specifically bar the capitalization of indirect cost categories such as "general and administrative overheads" or "training costs."

Per paragraph 20 of the CICA standard, "the cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity." No definition of the term "directly attributable" is provided in the standard, resulting in the need for management to exercise its professional judgement in assessing the degree of direct attribution that exists.

For rate regulated entities, paragraph 10 of the section provides criteria for assessing whether or not an entity's assets qualify as rate-regulated property, plant and equipment. Each of Hydro One's rate regulated subsidiaries, including Hydro One Networks' Transmission Business, meets these criteria. Meeting the rate regulated definition is important as it allows for a different method of capitalizing financing costs than that that would be used by an unregulated entity. Specifically, a qualifying enterprise may capitalize the rate regulator's allowance for funds used during construction, even if it includes a cost of equity component. In addition, assets that meet these criteria may be costed in accordance with regulatory guidance from a qualifying rate regulator, which may differ from the generally accepted basis of costing in use by non-rate regulated enterprises.

<u>Management Accounting</u>

Certified Management Accountants of Canada has developed and released guidance on certain general management accounting practices (MAPs), including overhead accounting. The applicable document is MAP-2400 "Indirect Costs." The relevant overhead accounting document discusses the issues related to designing costing systems for indirect costs. However, it is important to note that this MAP does not represent a primary source of financial accounting guidance within the formal legacy Canadian GAAP hierarchy. The purpose of this MAP is to discuss the issues related to designing management costing systems for indirect costs. Indirect costs are of all functional types, including administrative, manufacturing, logistical, and marketing. The issues related to handling indirect costs are general and independent of the functional nature of the cost. Hydro One's capitalization model complies with the indirect cost pool design recommended by MAP-2400. Since cost allocation forms an integral part of Hydro One's financial accounting capitalization model, it is appropriate that it is consistent with the approach for indirect cost allocation described below.

The MAP notes that when costs are used in contractual settings, such as in cost reimbursement contracts, insurance settlements, or transfer pricing where the price is based on cost, the criterion used to judge the adequacy of the costing system is whether its design could be reasonably expected to avoid material cost distortions in handling indirect costs. When various cost centers provide a significant level of services to themselves and to each other, the design of the costing system should reflect these interactions.

In general, the approach for designing the system of indirect cost pools should have the following steps:

- Classify the cost as direct or indirect;
- Determine if the cost is directly attributable to the cost object and assign it to the object to which it belongs if it is;
- Assign the cost to an appropriate indirect cost pool if it is indirect; and

- Choose an appropriate allocation basis for each indirect cost pool to assign the indirect costs in that pool to the final cost object.

MAP 2800 “Cost Allocation Rates” describes issues in the development and application of cost allocation bases or objects. The allocation of indirect costs to cost objects represents one of the most challenging tasks facing management accountants. This MAP identifies circumstances where care in allocating indirect costs is particularly important and it notes that ultimately the appropriate cost allocation should reflect the nature and purpose of the exercise.

An indirect cost that is allocated to a cost object should reflect that cost object’s use of the capacity resource to which the cost relates (effectively cost causality). As all cost allocations are by their nature subject to some degree of arbitrariness, the key is to develop a cost allocation which reasonably reflects the cause and effect relationship between resource use and resource cost.

MAP 6120 “Transfer Pricing in Regulated Environments” focuses on the pricing of transfers of goods or services in a regulated environment where goods or services are transferred between affiliates. Consistent with the requirements of the Board’s Affiliate Relationships Code and Hydro One’s relevant transfer pricing accounting policy described above, this MAP refers to full cost as an appropriate pricing method for such affiliate transactions in absence of market based pricing.

In general, the MAPs provide technical guidance to ensure some theoretical consistency between entities and consistent professional standards in management accounting and pricing. In general, management accounting concepts are common to various jurisdictions irrespective of which financial accounting framework applies. While management accounting is an internally focused activity, management accounting decisions and practices have real impacts on an entity’s financial accounting and financial statements.

2. US GAAP

As approved by the Board in its EB-2011-0268 decision, Hydro One Transmission has adopted US GAAP for rate-setting purposes effective January 1, 2012. Also, as noted by Hydro One in its application to adopt US GAAP as its basis for regulatory accounting and reporting, there are very few differences between legacy Canadian GAAP and existing US GAAP. Most of these differences relate to Balance sheet disclosure and presentation.

There is no formal standard within the body of documentation that represents US GAAP that provides comprehensive accounting guidance on the topic of property, plant and equipment. FASB’s ASC 360 “Property, Plant and Equipment” would appear to provide this but on closer inspection it is an aggregation of pre-codification standards dealing with specific capital accounting issues such as the capitalization of financing costs, business combinations, leases and industry-specific issues. It does not provide a complete accounting framework for fixed assets.

ASC 360 does define the cost of acquiring an asset. The historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. The term “activities” necessary to bring an asset to the condition and location necessary for its intended use is to be construed broadly, encompassing physical construction of the asset, as well as all the steps required to prepare the asset for its intended use. For example, cost includes administrative and technical activities during the preconstruction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation. The standard does not provide specific guidance that limits the types of expenditures or costs that qualify for capitalization.

In 2003, the American Institute of Certified Professional Accountants (AICPA) exposed a draft Statement of Position (SOP) on “Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment.” This was a proposed comprehensive standard intended to be issued before all standard setting accountability was later assigned to the FASB. The objective of the draft SOP was to replace the set of traditions and conventions that then made up US GAAP for property, plant, and equipment. The SOP proposed one consistent set of rules covering which costs that could be capitalized, either as part of the initial acquisition or construction of an asset, or during the asset’s useful life. This resulted in a draft standard that was very close in content to the current IFRS accounting standard for property, plant and equipment.

The draft proposed to limit the categories of costs that could be capitalized to those that were “directly related.” However, for the purposes of the proposed standard, “directly related” costs were interpreted as incremental direct costs, thus excluding indirect costs such as general and administrative overheads from capitalization. It specifically listed costs like executive management, corporate accounting, corporate legal, office management, human resource and marketing as indirect costs that would be ineligible for capitalization acquisition costs of capital assets. Respondents from capital intensive industries, including rate regulated utilities, were strongly opposed to the incremental cost capitalization principle include in the proposed SOP. Respondents found that a more appropriate method of costing capital assets was a full cost basis that includes direct costs and a reasonable attribution of indirect costs including general and administrative overheads. The incremental costing proposal was the primary reason why the exposure draft did not receive wide enough support to be adopted. As a result, the project was abandoned by the AICPA and not picked up as part of the FASB’s go-forward work agenda. The abandonment of this project, based on a rejection of the incremental costing model, provides solid evidence that US users were not willing to accept the loss of their ability to capitalize general and administrative overheads. The practice of capitalizing such expenditures remains GAAP in the US to this day.

ASC 980 “Regulated Operations” provides the detailed guidance on accounting for rate regulated operations and the recognition of regulatory assets and liabilities that previously resided in SFAS 71 “Accounting for the Effects of Certain Types of regulation.” SFAS 71 was the primary source of guidance under both US and legacy Canadian GAAP for guidance on rate regulated accounting matters. The effect is identical to that described above under Canadian GAAP, which is not surprising given that Canadian entities that were applying legacy Canadian GAAP looked to SFAS 71 in their application of regulatory accounting.

3. IFRS

Unlike US GAAP, IFRS provides very detailed and directive accounting guidance for property, plant and equipment in statement IAS 16. In addition, the IFRS framework has certain differences from those that underlay legacy CGAAP and US GAAP. For example, IFRS does not include a matching principle. Moreover, IFRS does not include any accounting recognition of the effects of rate regulation.

IAS 16 generally restricts capitalization of expenditures to those that are directly attributable to the construction or development of an asset. However, similar to the abandoned AICPA proposal in US GAAP, IAS 16 specifically prohibits the capitalization of certain expenditure categories like general and administrative overheads and training costs, even if a directly attributable argument can be made. A strong causal relationship is not sufficient to support capitalization given these prohibitions.

IFRS does not just have the effect of prohibiting the capitalization of general and administrative overheads. It also restricts the capitalization of other indirect expenditures where a “directly attributable” relationship cannot be demonstrated sufficiently to conform to international practice. For example, many indirect management and supervisory expenditures are not eligible for capitalization because they cannot be associated with a specific asset, not because they are unrelated to a capital work program. In Hydro One’s EB-2010-0002 application, the adoption of IFRS had the impact of reclassifying, from capital to OM&A, about $200 million per annum of various categories of overhead and indirect expenditures.

It is well known that IFRS does not deal with the generic issue of rate regulated accounting. The IASB has struggled to finalize its rate regulated accounting project over the last few years and has yet to produce a useful accounting standard to deal with the rate regulated accounting issue. This topic is still on its work plan. In addition, it is clear that the specific IFRS standards that have been issued were not designed to achieve regulatory objectives.

3. Summarize Regulatory Guidance

Key findings: Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable corporate support costs based on a cost causality model.

Canadian Regulatory Guidance

The Board has very recently revised its Accounting Procedures Handbook (APH) for Electricity Distribution Utilities to provide guidance to Ontario local distribution companies using modified IFRS as their approved basis for rate setting. The previous version of the APH provided guidance to utilities that had their rates set under legacy Canadian GAAP. In general, that APH required that regulatory accounting and reporting was based on legacy Canadian GAAP as is currently found in Part V of the CICA Handbook.

Article 410 provided that “property, plant and equipment should be recorded at cost, which includes the purchase price and other acquisition costs such as: option costs when an option is exercised, brokers’ commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.”

Article 230 defined the components of construction cost. Specifically, “the cost of construction properly included in the electric plant accounts shall include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other similar items as may be properly included in construction costs.”

The previous legacy Canadian GAAP APH provided recognition that many of the categories of expenditures included in Hydro One’s capital overhead rate do potentially qualify for capitalization, consistent with the general guidance found in legacy Canadian GAAP.

US Regulatory Guidance

The US Federal Energy Regulatory Commission (FERC) provides guidance that ensures consistency in accounting and reporting among US utilities. The FERC Uniform System of Accounts (USoA) is a key part of this accounting and reporting structure. The FERC provides guidelines for use by utilities in the US, including guidance on “overhead construction costs.” The FERC’s USoA guidance is provided under the overall framework of US GAAP.

- All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

- As far as practicable, the determination of payroll charges included in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

- For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

In addition, per FERC guidelines, allowable components of construction costs also include:

- Engineering and supervision - This includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

- General administration - This includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

- Engineering services – This includes the amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

While these cost elements are generally consistent with cost components included as capital by Hydro One under both legacy CGAAP and US GAAP, it is useful to note that many of these types of costs do not qualify for capitalization under IFRS IAS 16.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Key findings: Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures consistent with GAAP and formal regulatory guidance.

Overheads and indirect expenditures that relate to capital projects are those that are not directly charged to a capital program or project. While the expenditures may be causally or beneficially attributable to the capital project in aggregate, they may not be so easily assignable to a specific asset or capital project without the incurrence of significant additional expenditures that would have very limited benefit to either the shareholder or the rate payer.

Many regulated entities concentrate their corporate services within holding companies for efficiency in servicing the needs of regulated and unregulated subsidiaries. Hydro One Networks owns and operates two separately regulated transmission and distribution businesses. As such, it is able to provide many of their services on a shared basis rather than replicating them within each business. This results in lower costs and a more efficient delivery of electrical service to end customers. This model also results in a need for comparatively more cost allocation than seen in entities that do not share services. Under Hydro One's model, the costs of shared services are allocated to the serviced affiliates using the Black and Veatch reviewed methodology. Within each regulated business or subsidiary, allocated shared service costs are then classified as either current expense (i.e. OM&A) or capital. As previously stated, both cost allocation and cost classification are based on the same high level criteria – causality or benefit.

For companies that do not share common corporate support expenditures, such amounts are directly charged to capital, or more likely included in capital through the application of standard labour and non-labour rates. The organizational location of departments offering supporting services may influence whether the amount is charged to capital as an indirect cost (e.g. embedded in standard rates) or as an overhead through application of an overhead rate. Thus, a lower overhead capitalization rate compared to another utility may not necessarily be indicative of lower absolute capitalization of indirect support costs. Nor does a lower overhead rate indicate greater productivity or efficiency.

The absence of publicly available information on the organization structure, types and amounts of supporting functions' costs, standard cost structures and overhead allocation methodologies and rates make it very difficult to compare data between entities without conducting very extensive benchmarking studies, likely with the full cooperation of the other entity. However, while a precise peer-to-peer comparison on rates may not be achievable because of general lack of detailed comparative data, Hydro One Transmission's comparison work does indicate the use of a generally consistent practice of using cost causation principles to capitalize corporate support costs and other genera and administrative overheads.

Both legacy Canadian GAAP and US GAAP allow for the capitalization of directly attributable overheads costs under the general accounting principle of matching. This practice is supported by FERC guidance that incorporates the concept of intergenerational equity. Neither GAAP nor FERC provide explicit guidance on specific expenditures that may be capitalized or on cost allocation methods. The GAAP concept of matching and the regulatory principle of intergenerational equity both require the application of causality and benefit assessment to determine which expenditures should be capitalized. As documented in Black and Veatch's independent report, these are the same criteria used to allocate Hydro One's shared service costs to target subsidiaries and regulated businesses. These same criteria are used to determine the proportion of allocated expenditure that should be capitalized.

In its EB-2008-0408 Report, "Transition to International Financial Reporting Standards," under Issue 3.3, the Board commented on intervenor concerns that the adoption of IFRS, entailing a significant reduction in the types of expenditures that qualify for capitalization, could result in significant intergenerational inequities. Interestingly, in its report, the Board expressed an opinion that "the capitalization principles as they now appear in IFRS recognize the nature of indirect costs and whether they are truly attributable to capital projects. The ability of the Board to set just and reasonable rates is enhanced by clarity in capitalization principles that emphasize cost causality." Hydro One agrees with the view expressed in the last sentence and recognizes that the strict application of IFRS rules could result in significant shifts from rate base to revenue requirement for certain utilities. In section 3.3 of its report, the Board also noted that "It will be important for the Board to have a clear understanding of utility capitalization practices, and the effects, if any, of a shift to IFRS capitalization principles. The Board therefore supports the requirement for utilities to file their capitalization policies in their first cost of service filing after the transition to IFRS, and will also require that the revenue requirement impacts of any change in capitalization be specifically and separately quantified." The $200 million quantification of the impact of an IFRS capitalization policy was made clear in EB-2010-0002.

Hydro One Transmission undertakes large capital investments for network upgrades, local supply development projects and replacement and refurbishment of aging infrastructure. These capital projects are constructed and managed internally by the Transmission Business. Significant shared corporate support costs are directly caused by this capital construction program. If the internal construction program did not exist, many of these expenditures would not be required or could be reduced.

In addition, if such projects were outsourced to a turnkey engineering firm, many of these indirect costs and general and administrative overheads would be embedded in the construction costs charged by the turnkey contractor and would be capitalized without question, even under the constraints of IFRS. To comply with the regulatory principle of intergenerational equity, it is logical that the same classification as OM&A or capital should occur irrespective of whether the capital work is self-constructed or turn-keyed.

5. Conduct Industry Research

Key findings: Hydro One's practice, both in terms of the type and proportion of overhead and indirect expenditures capitalized, is consistent with the practices of other North American rate regulated utilities.

Methodology

As requested, Hydro One included a review of the practice of other rate regulated entities in other North American jurisdictions as part of the critical review of its cost capitalization policy. Hydro One notes that the Board asked the Company to gather comparative data but that this exercise was explicitly not intended to constitute a formal benchmarking exercise. This industry research included an examination of the financial statements and regulatory filings of some of the largest utilities in Canada and the US to obtain information on the nature of their overhead and indirect cost capitalization practices and rates. A summary of the research findings can be found in Appendix A.

During the course of its research, Hydro One found that publicly available information on the types of expenditures capitalized as overhead was very difficult to gather from available sources such as financial statements, securities filings and regulatory applications costs and the capitalization percentages. In addition, it was also very difficult to access comparable information on overhead percentages and rates. The Company expects this difficulty results from the fact that detailed disclosure of an entity's indirect cost and overhead accounting practices is not required disclosure under either US or legacy Canadian GAAP. In addition, there is no requirement for entities to disclose detailed information on which overheads or indirect costs are capitalized in their summary of significant accounting policies disclosed within their financial statements. Finally, risk and liability issues applicable to public securities filers have the effect of discouraging voluntary disclosure of information and make approaching another company for information difficult. As there is no offsetting incentive for companies to publicly disclose such information, virtually none do so.

In its review of the practices of other major transmission utilities, Hydro One started its review with major US transmission utilities. In recognition of the difficulty encountered in accessing detailed information on the overhead capitalization practices of these entities, the scope of the comparison was expanded to capture other major Canadian utilities and even large Ontario local distributors. Given the similarities between US and legacy Canadian GAAP, as well as similarities in the cost of service regulatory model in the Canadian and US jurisdictions, this was deemed to be appropriate.

Observation Summary

A detailed summary of Hydro One's findings from reviewing nine Canadian and nine US companies is included as Appendix A. Several other major US companies were also investigated but no useable information was derived from their publicly available financial or regulatory information.

The following table provides a high level summary of the findings with respect to overhead capitalization rate:

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) – 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

The comparative analysis performed for this report resulted in the identification of a range of acceptable accounting practices and capitalization rates prevalent in the industry. For example, an organization with a shared services structure where broad corporate management and administrative functions are centralized could be characterized by larger overhead allocations from the central indirect costs pool to business units. A more decentralized operation would have the majority of management and administrative costs directly attributed to the target activities, capital and operations.

The key observations made for the Canadian and US utilities researched were as follows:

- The majority of utilities capitalized general and administrative expenditures by including these costs in their overhead capitalization methodology. Some of the more common types of support expenditures within this category include finance, corporate communications, human resources, law, treasury, strategy, information technology, regulatory affairs and other corporate support costs.

- The most common capitalization methods in use appear to be a mix of direct allocation, cost drivers and time studies. In addition, there is evidence that external capitalization studies, such as the one Black and Veatch does for Hydro One, are performed from time to time by some entities.

- The majority of utilities capitalized corporate services expenditures under their capitalization approach. There are variations in the proportions that service expenditures are charged and capitalized as indirect costs (for example those included in the standard labour rates) or charged as overhead costs through the application of an overhead rate. Hydro One's comparison shows that most of corporate services costs appear to be charged to capital through overhead rates rather than being included in standard labour rates.

- All of the US utilities referenced compliance with FERC guidelines as the basis for their overhead capitalization practice.

6. Conclusion

Key findings: Hydro One's cost capitalization policy with respect to overhead and indirects expenditures is consistent with GAAP, regulatory guidance and regulatory practice. Hydro One's cost capitalization policy is appropriate.

As directed by the OEB, Hydro One critically reviewed its cost capitalization policy with a particular focus on overhead and indirect costs. Hydro One found that its treatment is not inconsistent with other major US and Canadian industry participants. In addition, Hydro One concluded that its methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with legacy Canadian and existing US GAAP. In addition, and more importantly, Hydro One's methodology is consistent with regulatory principles including the key goals of achieving intergenerational equity and avoiding cross subsidization.

Summary of Findings - Canadian Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates CGAAP *(as a % of gross operating costs)*	Reference
1.	BC Hydro, British Columbia Utilities Commission.	• Capitalized Overhead of $278M for 2011 is approximately 21% of operating costs. • Capitalized Overhead would be reduced to a $100 million under IFRS (9%). BC Hydro proposing to use a regulatory account to phase in the resulting increase over a 10 year period. • More recently they have proposed to use US GAAP.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 21% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• Amended F2012 to F2014 Revenue Requirements Application.
2.	Toronto Hydro Electric System (THES), Ontario Energy Board(OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Proposing to use US GAAP from 2012 with no material impact on overhead rates.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board) • Fleet indirects and procurement indirects are recovered through standard labour rates.	• *~ 22%* *(percentage is derived)*	• Exhibit C1, Tab 3, schedule 4(EB-2011-0144).

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
3.	Hydro Ottawa, Ontario Energy Board (OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Overhead rates will reduce to 10.3% on adopting IFRS based capitalization approach. Allocation to capital reduced by $10.5 million.	• Corporate Costs – Chief Regulatory officer, General Council, Hold Co Corporate Costs, COOs office, Finance, Supply Chain, Human Resource, IT, Supervision, Operations Engineering.	• 15.4% *(Percentage extracted from referenced document)*	• 2012 EDR Application.
4.	Fortis BC, British Columbia Utilities Commission.	• Fortis BC (Electricity) requested approval of US GAAP for rate setting. As part of its 2012-2013 application Fortis BC updated its methodology for calculating Capitalized Overhead resulting in a 23.9% capitalization rate. Fortis BC proposes to continue using the 20% for 2012-2013. • Fortis BC (Electricity) derives their corporate overhead rate through a 3 step process. First a driver is identified for each corporate department. Next the department costs are allocated to the operating business units (Generation, Network Services, Customer Service) using the drivers. Finally the relative proportion of capital related work in the operating business units are determined based on relative labour hours charge to O&M versus capital in 2010. : Generation 75%, Networks Service Customer Service 13 %.	• Fortis BC (electricity) Corporate Costs – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Health and Safety, Environmental. • No detailed component information available for Fortis BC (Gas)	• Electricity-20% (increased to 23.9% beyond 2012-2013) • Gas - 14% *(Percentage extracted from referenced document)*	• 2012-2013 Revenue Requirement Application.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
5.	Enmax Power Corporation, Alberta Utilities Commission.	• The Alberta Utilities Corporation (AUC) approved a 7 year Formula Based Ratemaking for the period 2007 to 2014 for Transmission and Distribution. Included was approval for a 19% overhead capitalization rate for the term of the plan with a 3% escalation per year. • A mix of time study, cost-drivers and direct attribution is used for allocation of overhead costs.	• **Corporate Costs** – (Finance, Information Technology, Human Resources, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 19% *(Percentage extracted from referenced document)*	• 2007-2016 Formula Based Ratemaking Decision issued in March 25, 2009.
6.	Union Gas, Ontario Energy Board.	• Union Gas forecasts capital overhead as 14.9% of total utility operating and maintenance costs in 2013. This is consistent with the 2007 Board-approved levels of 15%. • A mix of direct attribution, time studies and cost drivers is used for allocation of overhead costs.	• **Corporate Costs** – (Executive, Asset Operations, Regulatory and Business Services, Finance, Human Resources, Corporate Services, Legal, Strategic Development, Information Technology.	• 14.9% *(Percentage extracted from referenced document)*	• EB-2011-0210, Exhibit D1, Tab 2.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
7.	Enbridge Gas Distribution.	• Administrative and general overheads are capitalized based on cost drivers/time study and approved by Enbridge's Board.	• Detailed information on cost components not available.	• 6.8% *(Percentage extracted from referenced document)*	• EB-2011-0008, Exhibit B, Tab 4, Schedule 2.
8.	Newfoundland Power, Board of Commissioners of Public Utilities.	• Certain general expenses related, either directly or indirectly, to the Company's capital program are capitalized based on approval from the regulator. • For 2012 General Expenses Capitalized is $2.8 million Compared to Operating Costs of $52.7 million.	• Detailed information on cost components not available.	• 5% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• 2012 Capital Budget Application and 2010 General Rate Application.
9.	Powerstream, Ontario Energy Board (OEB).	• Overheads allocated based on payroll burden study and include management, engineering, stores and vehicle burdens loaded to standard labour rates.	• Detailed information on cost components not available.	• Management Burden - 6% • Engineering Burden - 60% *(Percentage extracted from referenced document)*	• EB-2008-0244, Exhibit B1, Tab 3, Schedule 1.

Summary of Findings - U.S. Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
1.	Southern California Edison, California Public Utilities Commission (CPUC).	• Administrative and General ("A&G") overhead costs are based on study approved by the regulator. • Overheads allocated based on cost drivers/time study and include cost of corporate functions and services like human resource, IT, corporate finance and risk assessment and strategy. Pensions and benefits are capitalized at 37.7%.	• Corporate Cost – Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, Treasurer. • Strategy – General Functions and Information Technology. • Operations Support – Training, Environmental, Health and Safety.	• 19.4% *(Percentage extracted from referenced document)*	• 2012 General Rate Case Exhibit No. SCE-07, Vol.01 Chapter I, X and XI and work papers • 2009- General Rate Case proceedings with CPUC.
2.	San Diego Gas & Electric Company (SDG&E), California Public Utilities Commission (CPUC).	• A percentage of certain A&G direct costs, including A&G Salaries, shared service costs, outside services employed, are reassigned to construction each year. The transfer rate to construction projects is determined by an A&G effort study last conducted in 2009 and approved by CPUC. Other costs capitalized include fleet, purchasing, warehousing and pension benefits.	• A&G costs represent corporate services and include A&G salaries, shared services, office supplies and expenses and outside services employed.	• Labour overheads to capital-33.9%. • A&G costs to capital - 18.1% *(Percentage extracted from referenced document)*	• 2012 Gen. Rate Case Exhibit SDG&E-43 Segmentation & Re-Assignment Rates and work papers

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
3.	Pacific Gas & Electric Company (PG&E), California Public Utilities Commission (CPUC).	• Overhead allocation is based on detailed review by Corporate Service departments to calculate the appropriate administrative and general (A&G) capital allocation. Pensions and benefits are also capitalized. • No information available on non-labour related overhead allocation rates.	• Detailed component information on corporate services was not available. • A significant portion comprised of A&G labour costs.	• 7.33% of A&G labour costs allocated to capital. *(Percentage extracted from referenced document)*	• Decision on Test Year 2011 A.09-12-020, I.10-07-027 • Ex PGE-006: 2011 GRC Prepared Testimony: Exhibit 6 – Admin & General Expenses.
4.	Kansas City Power and Light Company, Missouri Public Service Commission	• Indirect A&G costs include corporate services costs, executive salaries and indirect labour. • The Uniform System of Accounts addresses the indirect allocation of A&G payroll to construction activity.	• A&G costs include corporate services - (Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, and Treasurer).	• The labour allocation to construction at 19.33% was based on a study filed with the regulator in 2006. *(Percentage extracted from referenced document)*	• Missouri PSC, Utility Services Division, Direct Testimony of Kimberly K. Bolin, Staff, Case No. ER-2006-0314.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
5.	Commonwealth Edison Illinois Public Utilities Commission	• An Administrative and General Overheads ("A&G") study was done by Commonwealth Edison, (ComED) to justify its overhead allocation between capital and OM&A to the regulator for the year 2001 to 2004. • The study was done by an external consultant Alliance Consulting Group ("ACG"). • The study showed that since about 1999 ComEd began incurring increased levels of capital expenditures compared to prior years primarily reflecting ComEd's increased investment programs to improve the reliability of its distribution system. In addition, during the period, ComEd implemented accounting changes and made operational decisions that reflect a systematic plan to shift costs from O&M expense to capital.	• Indirect cost components include – Labour, Employee Benefits, Supervision, General and Administrative, Contracting, Affiliate Services, Indirect Materials, Vehicle Fleet and Corporate and Other Support.	• A&G distributed to capital- ▪ 2001-57.2% ▪ 2002-60% ▪ 2003-70.9% ▪ 2004-71.4% • Capitalization rate information is not available. *(Percentage extracted from referenced document)*	• A&G Effort Study, Chapter VI Analytical and Other Review, Page A-305.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
6.	Bonneville Power Administration (BPA).	• Capitalized costs include direct labour and materials, payments to contractors, indirect charges for engineering supervision and similar overhead items.	• Detailed information not available. • Includes indirect costs for engineering and supervision**.**	• Capitalization rate information is not available.	• Bonneville Power, 2011 Annual Report, Audited FS
7.	UNS Electric (Arizona), Arizona Corporation Commission	• It appears that they capitalize A&G expenses according to Decision of Arizona Corporation Commission on rates for 2008. Expenses are related to shared service group and administrative costs associated with installation of equipment to serve customers, even though such costs can not be traced directly to individualized capital projects	• Capitalized A&G includes shared services cost which represent general and administrative overheads and corporate services**.**	• Capitalization rate information is not available	• Decision 70360, Docket No. E-04204A-06-0783, Appln. of UNS Electric Inc. before Arizona Corporat-ion Comm.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
8.	Seattle City Light (Seattle City Council)	• A&G capitalized is assumed in financial forecast but no rates given.	• Detailed information not available.	• Capitalization rate information is not available	• Revenue Require-ments Presentation, RAC Meeting 2, Sept 22, 2009.
9.	Illinois Public Utilities Commission	The Uniform System of Accounts for Electric Utilities Operating in Illinois talks about overhead allocation: • Overhead construction costs to be charged on the basis of the amounts of such overheads reasonably applicable. • Determination of payroll charges included in const. overheads to be based on time cards. Where impractical, special studies shall be made periodically.		• Capitalization rate information is not available but the Illinois utilities USofA support capitalization of indirect costs and general and administrative overheads.	• Working Copy of the USoA for Electric Utilities Operating in Illinois, Illinois Commerce Comm. Accounting Department August 1, 2007.

COMMON ASSET ALLOCATION

1.0 INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Distribution and Transmission business units.

Similar to the corporate common costs discussed in Exhibit C1, Tab 5, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment (“T&WE”).

2.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (4% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1 summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1
Summary of Gross Fixed Assets
as at December 31, 2012 ($ Million)

	Transmission	Distribution	Total
Total Fixed Assets	13,540.7	8,363.0	21,903.7
Shared Assets (in Total)	511.7	698.7	1,210.4
Shared Asset %	42.3%	57.7%	100%

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2 shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2012.

Table 2
Details of Shared Net Fixed Assets
as at December 31, 2012 ($ Million)

Asset	Gross Asset Value	Accumulated Depreciation	Net Book Value
Shared Major Assets	539.2	292.2	247.0
Shared Minor Assets	671.2	386.2	285.0
Total Shared Assets	**1,210.4**	**678.4**	**532.0**

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying transmission and distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, the Company commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

The Company has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently endorsed by the Board in the previous Distribution rate Decision RP-2005-0020/EB-2005-0378/EB-2007-0681 and in the subsequent Transmission rate Decision EB-2006-0501/EB2008-0272/EB-2010-0002/EB-2012-0031, and was also used in the Company's latest application for Distribution Rates for 2010 and 2011 (EB-2009-0096).

The appropriate use of the common asset allocation methodology for the 2014 to 2019 test years has been reviewed and confirmed by B&V in 2013, and is provided as Attachment 1 to this Exhibit.

Due to the significance of Cornerstone as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2012.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2012 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $21,903.7 million			
Transmission (Total)	$13,540.7	Distribution (Total)	$8,363.0
Transmission (Direct)	$13,029.0	Distribution (Direct)	$7,664.3
Transmission (Common)	$511.7	Distribution (Common)	$698.7

REVIEW OF SHARED ASSETS ALLOCATION (DISTRIBUTION) – 2013

PREPARED FOR

Hydro One Networks Inc.

19 SEPTEMBER 2013

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I. Summary

A. BACKGROUND AND PURPOSE

Black & Veatch ("B&V" or "we") is pleased to submit this Report on our Review of Shared Assets Allocation (Distribution) – 2013 to Hydro One Networks Inc. ("HONI") This Report describes the review that B&V performed, at the request of Hydro One, of Hydro One's allocation of the costs of Shared Assets in its 2015-2019 Distribution Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is original cost (i.e., gross book value) as derived of December 31, 2012.

In 2005, B&V recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Shared Assets between its Distribution business and Transmission business, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). B&V's objective in allocating the Shared Assets was to ensure that the allocation was reasonable, reflected best practices and was consistent with the allocation of common corporate costs, as discussed in our *Review of Allocation of Common Corporate Costs (Distribution)-* dated September 19, 2013 ("2013 Common Corporate Costs Report- Distribution").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW / ASSET VALUES	HYDRO ONE FILING	B&V REPORT
2006 Review 12/31/2005	2006 Distribution Rates	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review 12/31/2007	2008 Transmission Rates	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review (Distribution) 12/31/2008	2010/2011 Distribution Rates	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2009 Review (Transmission) 12/31/2008	2011/2012 Transmission Rates	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010
2011 Review (Transmission) 12/31/2010	2013/2014 Transmission Rates	*Report on Shared Assets Allocation (Transmission) 2012* dated February 1, 2012

The OEB-accepted methodology has been applied by Hydro One to its Business Plan for 2014-19 ("BP 2014-19") data for its 2015-2019 Distribution Rates filing. This Report describes the "Review of Shared Assets Allocation (Distribution)" that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2014-19, and presents B&V's conclusions.

In its 2015-2019 Distribution Rates filing, Hydro One has allocated 57.7% of the cost of the Shared Assets to its Distribution business, and 42.3% to its Transmission business. These ratios are approximately the same as in its 2011/2012 Transmission Rates filing which allocated 59.9% to the Distribution business and 40.1% to the Transmission business.

In addition, Hydro One has developed transfer price charge rates for the Telecom and Remotes businesses, to be used in allocating to those businesses a portion of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return). In the past, before Cornerstone assets had been placed in service, no Shared Assets were assigned to Telecom or Remotes because the amounts would have been very small.

No Shared Assets are allocated to Brampton, because it does not use these assets.

B. TYPES OF SHARED ASSETS

Hydro One provided B&V with a list of the Shared Assets, by Asset Group and Asset Subgroup, as shown in Table 1.

Table 1 - Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	■ Software ■ Buildings and Telecommunications equipment
Minor Fixed Assets ("MFA")	■ Aircraft ■ Computer Hardware ■ Office equipment ■ Service equipment- Miscellaneous ■ Service equipment- Measurement and Testing ■ Service equipment- Storage ■ Tools ■ Transportation Work Equipment ■ Transportation Work Equipment- Power equipment

If an asset was estimated to be used at least 95% in either Transmission or Distribution, the cost of that asset was removed from Shared Assets and directly assigned to that business.

C. SUMMARY OF APPROACH

Allocation of Asset Costs to Transmission and Distribution

A cost driver was assigned to each asset (i.e., a building within Major Assets), asset type (i.e, Pickup Trucks within TWE) or Asset Subgroup, based on discussions with Hydro One personnel to ascertain what cost driver was most closely related to the usage of the asset or the Asset Subgroup. The cost drivers used to allocate the Shared Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services. The specific steps used for each Asset Group and Subgroup are discussed below. The amounts allocated to Transmission and Distribution are summarized in Table 2.

Development of Transfer Price Charge Rates for Telecom and Remotes

The transfer price charge rates represent the usage of the Shared Assets by the Telecom and Remotes businesses. Our approach to developing the transfer price charge rates was as follows:

- The portion of each asset that should be allocated to Telecom and Remotes based on the appropriate cost driver was determined.
- The total dollar amount allocated to Telecom, representing Shared Asset cost, was computed for each asset by multiplying the Telecom share of usage by the asset cost; these dollar amounts were summed and divided by the category total cost to determine the Telecom share for the category. The same was done for Remotes. Table 3 presents the Telecom and remotes shares.
- The percentages should be applied to each component of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return), to compute the dollar amount charged to Telecom and Remotes. The amounts charged to Telecom and Remotes should be applied to reduce the revenue requirement recovered from rate payers of the Transmission and Distribution businesses.

  For example, the study determined that Telecom uses 0.42% (Table 3) of the shared Major Assets owned by HONI. As such, 0.42% of the revenue requirement associated with major assets is charged to Telecom. The revenue requirement calculated for HONI will include 100% of the assets, however, the other revenues received from the Hydro One Inc. subsidiaries will reduce the revenue requirement which is used to derive the tariff rates.

II. Descriptions of Asset Groups

A. MAJOR ASSETS

Software

Most of the software included in Shared Assets was for Hydro One's Cornerstone project, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. These costs were allocated using a cost driver that reflects the activities supported. Infrastructure costs related to each phase were allocated based on the activities those phases support.

Buildings and Telecommunications Equipment

Each asset included in Buildings and Telecommunications Shared Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- **Specific estimation for a building.** For example, Sudbury Service Centre has estimated usage of Transmission-20% / Distribution-80%.
- **Direct assignment based on type of usage**. For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012 and determined that Fleet usage is Transmission- 27.26% and Distribution- 72.74%; therefore the costs for buildings used for Fleet were allocated using these percentages.

  Buildings used for Training were allocated using the cost driver Headcount.
- **Cost drivers based on usage.** For example, Buildings used to manage both Distribution and Transmission projects are allocated using the cost driver *ProgramProjectCosts*, developed as part of the 2013 Common Corporate Costs Report- Distribution study.

B. MINOR FIXED ASSETS

Each component of Minor Fixed Assets includes many individual items. B&V reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using a cost driver based on the number of *Workstations* (50% weight) and the cost driver *Headcount* (50% weight).
- **Office equipment –** Includes office furniture and other office equipment. Allocated using the cost driver *Headcount*.
- **Service equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using *Total Common Costs* cost driver, developed as part of the 2013 Common Corporate Costs Report-Distribution study.
- **Service equipment- Measurement and Testing** – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.

- **Service equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on spending for *Operating and Maintenance costs and Capital spending*.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.
- **Transportation & Work Equipment** – Includes primarily Vehicles. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009-2012. Except for items representing less than 1.0% of cost, the usage for all of the Transportation & Work Equipment Shared Assets were recorded on time sheets and included in the computation of the Fleet cost driver.

The results are summarized in Table 2.

III. Summary of Results

Table 2 presents the allocation of Shared Assets to Distribution and Transmission.

Table 2 - Summary of Shared Assets Allocation

YEAR - END 2012 $ MILLIONS COST	TOTAL	DISTRIBU-TION	TRANS-MISSION	DISTRIBU-TION %	TRANS-MISSION %
Major Assets					
Software	$444.1	$205.9	$238.2	46.4%	53.6%
Building / Telecom	95.1	43.7	51.4	46.0%	54.0%
Total	**539.2**	**249.6**	**289.6**	**46.3%**	**53.7%**
Minor Fixed Assets					
Aircraft	19.1	5.2	13.9	27.2%	72.8%
Computer Hardware	89.2	40.4	48.8	45.3%	54.7%
Office Equipment	10.0	4.5	5.5	45.0%	55.0%
Service- Misc.	5.2	2.8	2.4	53.8%	46.2%
Service- Measure/Test	11.8	11.8	--	100.0%	0.0%
Service- Storage	3.6	1.5	2.1	41.7%	58.3%
Tools	8.3	1.7	6.6	20.5%	79.5%
Transportation & Work Equipment	524.0	381.1	142.9	72.7%	27.3%
Total	**671.2**	**449.0**	**222.2**	**66.9%**	**33.1%**
Total - All Shared Assets	**$1,210.4**	**$698.6**	**$511.8**	**57.7%**	**42.3%**

Table 3 presents the Shared Assets transfer price charges for Telecom and Remotes.

Table 3 - Transfer Price Charges for Other Businesses

ASSET GROUP	TELECOM	REMOTES
Major Assets	0.42%	0.24%
Minor Fixed Assets	0.25%	0.12%
Total - All Shared Assets	**0.30%**	**0.16%**

Expert Evidence Statement from Black & Veatch Corporation

This Statement is provided in compliance with Ontario Energy Board ("Board") Rule 13A, regarding the report 'Review of Shared Assets Allocation (Distribution) – 2013' ("Report") dated September 19, 2013, prepared by Black & Veatch Corporation ("Black & Veatch").

Consultant:

Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

Black & Veatch, through its Management Consulting Division, provides strategic, economic and management consulting, specializing in energy matters, in areas such as economic analysis, strategy development, operational assessment, industry restructuring support, litigation and regulatory support and technical analysis.

Qualifications:

The lead expert on this project was:

> *Howard Gorman*
>
> Howard Gorman has 25 years of diversified experience in the energy industry and over 30 years of experience covering all areas of finance. He specializes in rate and regulatory matters, including electric and gas revenue of requirements, allocated cost of service and rate design; accounting and costing; energy project financing and analysis; energy asset valuations, acquisitions and divestitures; mergers and related management and organizational matters; economic and financial planning. Mr. Gorman has extensive experience in rate and regulatory matters for electric and gas utilities, including: Developing revenue requirements; Identifying customer class cross-subsidizations; Revenue allocation and rate design; Inter-affiliate cost allocation; and Budgeting and costing. He has testified before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy

Board, Pennsylvania Public Utility Commission and Rhode Island Public Utilities Commission. Mr. Gorman received a B.S. degree in Accounting from New York University (1976) and an M.B.A. from Harvard Business School (1981). He is a New York State licensed Certified Public Accountant.

Instructions Provided:

The instructions provided to Black & Veatch in preparing the Report were:

- Recommend a best practice methodology to distribute Hydro One Inc.'s Common Corporate assets among the business units that use them. This recommendation could include the continuation of the existing methodology, the continuation of the existing methodology with modifications or the proposal of a new methodology.
- Prepare a Report of the recommended Common Corporate Assets Methodology to be used in future rate applications. This report will include a conclusion, definitions, a summary of every factor used in the methodology and the proposed methodology.
- Propose and analyze all drivers used for allocation.
- Prepare responses to Interrogatories from Interveners during a rate application relating to the proposed Asset Allocation methodology.
- Be available to testify to the proposed methodology during a future rate application.
- Prepare final Common Corporate Assets allocation report, reflecting the current Business Plan and including both the Distribution and Transmission businesses, to be used in Cost of Service applications.
- In support of the successful Proponent's work, Hydro One's management will respond to all requests for basic information and/or supporting documentation.

Basis of Evidence:

The basis for the evidence is set forth in the Section IB of the Report, *Types of Shared Assets,* and Section IC of the Report, *Summary of Approach* and Section II of the Report, *Descriptions of Asset Groups*.

Context of Evidence:

This evidence is not provided in response to another expert's evidence. In 2004, B&V (formerly RJ Rudden and Associates) was engaged by Hydro One to recommend a best practice methodology to distribute the costs of Shared Assets, between its Transmission and Distribution businesses and other businesses. B&V recommended a methodology which was adopted by Hydro One and accepted by the Board in its EB-2006-0501 Decision with Reasons, dated August 16, 2007. The accepted methodology has been reviewed and updated by B&V and accepted by the Board as part of subsequent Transmission and Distribution rate filings EB-2007-0681, EB-2008-0272, EB-2009-0096, EB-2010-0002 and EB-2012-0031. To remain consistent with the Board's approved methodology, a similar review and update process has been done as part of this filing.

Confirmation:

The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert:

Black & Veatch Corporation

By Russell A. Feingold, Vice President, Management Consulting Division

Date:

January 10, 2014

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and amount of Hydro One Distribution's depreciation and amortization expense for the 2015 to 2019 test years.

The depreciation and amortization expense accepted by the Board for Hydro One's 2010 and 2011 Electricity Distribution revenue requirement, followed the methodology originally accepted by the Board for 2006 rates. The depreciation rates in the RP-2005-0020/EB-2005-0378 proceeding were supported by an independent depreciation study completed in June 2005 by Foster Associates Inc. (Foster Associates). The Board accepted the costs flowing from this depreciation study for the purpose of supporting Hydro One Distribution's rates in 2006 and similarly accepted the methodology again in the 2007-0681 proceeding for 2008 rates.

Foster Associates have completed a new full depreciation study covering Hydro One Networks' distribution and common assets for purposes of determining depreciation and amortization expense for the 2015 – 2019 test years. The Foster Associates' study is attached as Attachment 1 to this exhibit.

Consistent with the findings and recommendations of the Foster study combined depreciation and amortization expense levels for the test years are: 2015 - $353.6 million; 2016 - $373.2 million; 2017 - $390.5 million; 2018 - $404.6 million; and 2019 - $416.6 million.

2.0 DEPRECIATION EXPENSE

Based on the recommendations found in Foster Associates' new study, the depreciation expense amounts for each of the five test years can be found in the detailed depreciation schedules filed at Exhibit C2, Tab 4, Schedule 1.

Table 1
Distribution Depreciation Expense
$ Million

Description	Historic			Bridge		Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Depreciation On Fixed Assets	232.7	250.4	269.3	286.9	253.6	298.2	308.0	321.8	333.7	343.9
Less Capitalized Depreciation	(15.4)	(16.7)	(17.1)	(13.8)	(12.7)	(13.2)	(13.7)	(14.0)	(14.4)	(14.8)
Asset Removal Costs	43.2	45.5	46.5	43.5	50.7	54.5	57.0	60.4	63.3	65.8
Losses/(Gains) On Asset Disposition	(0.2)	(0.1)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	260.4	279.2	298.9	316.5	291.7	339.5	351.3	368.1	382.6	395.0

The increase in 2015 depreciation on fixed assets amount relative to the 2014 amount is due to the higher level of fixed assets placed in service in 2015, by including assets related to Distributed Generation, Smart Meter, and Smart Grid into the core rate base, previously recorded as regulatory assets.

Capitalized depreciation refers to depreciation on transport & work equipment and other minor fixed assets (e.g. tools) that is charged to capital work projects. For purposes of calculating the revenue requirement, capitalized depreciation is deducted from annual depreciation expense, as it is treated as a capital expenditure.

Fixed asset removal costs are presented as part of depreciation expense for financial reporting purposes and are recorded on an "as incurred" basis unless an asset retirement obligation has been recorded.

Losses/gains on asset disposition may result from the sale of assets. Losses/gains on asset disposition are based on historic actual experience and trends and are not separately forecast for the bridge or test years.

3.0 AMORTIZATION EXPENSE

Amortization expense pertains to certain regulatory amounts the Board has allowed Hydro One Distribution to defer for recovery at a future date. The Board has, in past decisions, approved the deferred balance and prescribed the method and time period over which the balance in each regulatory deferral or variance account may be disposed.

Historical, bridge and test year amortization schedules are filed at Exhibit C2, Tab 4, Schedule 1.

Table 2
Distribution Amortization Expense
$ Million

Description	Historic			Bridge		Test				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Environmental	9.4	7.7	9.2	7.5	11.2	14.2	22.0	22.4	22.0	21.6
Other Amortization	7.7	0	0	0	0	0	0	0	0	0
Total	17.2	7.7	9.2	7.5	11.2	14.2	22.0	22.4	22.0	21.6

3.1 Environmental

Hydro One Distribution records an obligation for the net present value of estimated future expenditures required to remediate legacy environmental contamination inherited from Ontario Hydro upon demerger in 1999. Since these expenditures are expected to be recovered in future rates, Hydro One Distribution also records these amounts as a regulatory asset for financial reporting purposes. This regulatory asset is amortized on a basis consistent with the pattern of actual expenditures incurred. The combined work program to manage polychlorinated biphenyls (PCBs) and to carry out Hydro One's land assessment and remediation (LAR) program are currently estimated to continue until the year 2025. When OM&A work program costs are incurred, there is a corresponding credit to OM&A for the environmental expenditures to reflect the fact that the cost is reflected in revenue requirement as amortization expense and not as OM&A. The work programs are discussed further in Exhibit C1, Tab 2, Schedule 2.

3.2 Other Amortization

The other amortization in 2010 related to the final year of asset amortization for a subset of the total net regulatory assets included in the Regulatory Asset Recovery Account (RARA) II rate rider. For elements of the RARA II account that represented deferred costs that had not yet been recorded in the Statement of Operations, an amortization entry was required to record that cost. The remainder for the RARA recovery was reflected as a balance sheet entry (i.e. regulatory receivable) for which no amortization expense recognition was required.

2013 Depreciation Rate Review

— Distribution Operations
— Common Operations

foster associates

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DISTRIBUTION

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SECTION I

Executive Summary

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for Distribution and Common plant owned and operated by Hydro One Networks Inc. (Company or Hydro One Networks). Work on this review, conducted by Foster Associates, Inc. (Foster Associates), commenced in April 2013 and progressed through mid–August, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Rockville, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

PLANT ACCOUNT STRUCTURE

The hierarchical structure of the plant accounting records maintained by Hydro One Networks for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Category ID); and c) vintage identification (Asset ID).

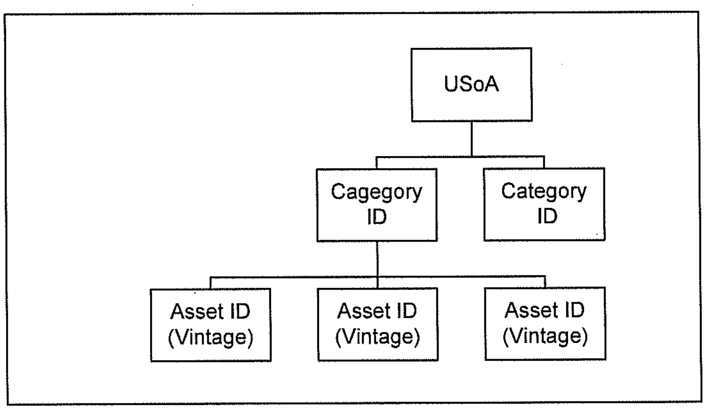

Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Category ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Category ID is an aggregation of vintage costs sharing common physical or functional attributes. All vintages of power transformers larger than 230 kV, for example, or all vintages of underground cable are classified in unique Category IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

CURRENT DEPRECIATION RATES

Depreciation rates currently used by Hydro One Networks for Distribution and Common operations were developed in a 2005 depreciation review conducted by Foster Associates. In RP–2005–0020/EB–2005–0378 (Decision dated April 12, 2006), the Ontario Energy Board (OEB) accepted the depreciation expense flowing from the depreciation review for purposes of setting rates in the test year. The OEB noted, however, "that such approval should not be construed as Board acceptance of each specific recommendation contained in the study or that the study should form the definitive basis for depreciation studies for other electricity distributors."

Life tables were constructed in the 2005 review for each USoA plant account for which retirements were recorded over the period 2000–2004. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2005 review were derived from a composite of parameters *(i.e.*, projection lives and projection curves) recommended by the former Ontario Hydro internal Depreciation Review Committee (DRC) for asset categories within a USoA category. The dominant projection curve and dollar–weighted average projection life (rounded to the nearest integer) of the constituent asset categories were selected to describe the forces of retirement acting upon a USoA plant account.[1]

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[1]In 1954, by joint agreement of the Engineering, Operations and Comptroller's Division of Ontario Hydro, average service lives were estimated for each of the Company's various plant accounts. The estimated lives were based on engineering/financial judgment and information gathered regarding service lives used by other utilities. Statistical studies based on survivor curves were introduced in 1959 to further improve the estimation of life expectancies. The DRC was established in 1973 to provide formal engineering review for various classes of assets. The role of the committee was expanded in 1975 to include responsibility for recommending service lives and service costs (*i.e.*, provisions for fixed asset removal costs) of all assets. The DRC annually reviewed the service lives of all major facilities and a selection of plant components, with the objective of reviewing all plant components at least once every five years. DRC recommendations were based on factors such as operating experience, retirement history, engineering judgment, expected regular maintenance and system requirements. The DRC review process was discontinued by Hydro One Networks in 1998.

2013 Depreciation Rate Review

The principal findings and recommendations of the Hydro One Networks 2013 Depreciation Rate Review are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each USoA rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, and average remaining life. Statement E provides the computation of proposed USoA projection lives derived from an analysis of component category lives. A set of statements is included in this report for both Distribution (BU 220) and Common (BU 300) Operations.

Scope of Review

Principal activities undertaken in the 2013 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One Networks plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

Depreciation System

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that produces acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for a group plant account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, Hydro One Networks is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the general plant amortization categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1610	Computer Software	10 yrs.
1915	Office Furniture and Equipment	7 yrs.
1920	Computer Hardware - Minor	5 yrs.
1925	Computer Software - Major	6 yrs.
1935	Stores Equipment	8 yrs.
1940	Tools, Shop and Garage Equipment	6 yrs.
1945	Measuring and Testing Equipment	5 yrs.
1960	Miscellaneous Equipment	5 yrs.

Table 1. Amortization Accounts

With the exception of USoA Accounts 1610 and 1925, general plant amortization categories are only recorded in BU 300. Accounts 1610 and 1925 (recorded in both BU 220 and 300) are currently depreciable categories in BU 220. Amortization accounting is proposed in the 2013 review for BU 220 to achieve consistency with the treatment adopted in BU 300. Additionally, with the exception of Account 1925, currently approved amortization periods are retained for all amortization categories. The proposed amortization period for Account 1925 (Computer Software – Major) has been adjusted from ten to six years to more nearly align the amortization period with the Company's hardware/software refresh policy.

Recommended Depreciation Rates

Table 2 provides a summary of the changes in annual rates and accruals resulting from the 2013 review of Hydro One Networks' Distribution Operations.

Function	Accrual Rate			2013 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	9.36%	1.14%	-8.22%	$6,315,745	$770,815	($5,544,930)
Generation	1.16%	-11.69%	-12.85%	8,224	(82,565)	(90,789)
Distribution	2.44%	2.27%	-0.17%	181,363,396	169,126,904	(12,236,492)
General Plant	6.53%	8.10%	1.57%	21,962,228	27,246,910	5,284,682
Total	2.67%	2.51%	-0.16%	$209,649,593	$197,062,064	($12,587,529)

Table 2. Distribution Operations

The composite accrual rate recommended for Distribution Operations is 2.51 percent. The current equivalent rate is 2.67 percent. The recommended change in the composite rate is a reduction of 0.16 percentage points.

A continued application of current rates would provide annualized depreciation expense of $209,649,593 compared with an annualized expense of $197,062,064 using the proposed rates. The resulting 2013 expense reduction is $12,587,529.

Table 3 provides a summary of the changes in annual depreciation rates and accruals derived for the Company's Common Operations.

Function	Accrual Rate			2013 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	9.28%	9.28%	0.00%	$33,865,737	$33,865,737	$0
General	6.28%	8.41%	2.13%	19,064,453	25,542,054	6,477,601
Total	7.91%	8.88%	0.97%	$52,930,190	$59,407,791	$6,477,601

Table 3. Common Operations

Adjustments developed in the 2013 review produce a composite depreciation rate of 8.88 percent. Depreciation expense is currently accrued at an equivalent composite rate of 7.91 percent. The proposed change in the composite depreciation rate is, therefore, an increase of 0.97 percentage points.

A continued application of current rates would provide annualized depreciation expense of $52,930,190 compared with an annualized expense of $59,407,791 using the rates developed in the review. The increase for Common Operations proposed in the 2013 review is $6,477,601.

Study Procedure

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. The 2013 review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for Distribution and Common Operations. The proposed rates are subject to approval by the Ontario Energy Board.

SCOPE

The steps involved in conducting the 2013 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2013 review included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by Hydro One Networks provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset categories maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.[2] The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2013 depreciation review was assembled by Hydro One Networks personnel and coded by Foster Associates. Plant accounting transactions recorded between January 1, 2005 and July 31, 2009 were extracted from the PeopleSoft system, coded and appended to the database used in conducting the 2005 review. Transactions recorded between August 1, 2009 and December 31, 2012 were extracted from the SAP system. An additional dataset of category plant balances at December 31, 2012 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2012 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One Networks. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One Networks. The integrity of the assembled database, however, was confirmed by the Company.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

[2]In 2003, Hydro One undertook a two–phase project to a) map asset categories maintained in PeopleSoft to USoA plant classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re–mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset categories maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre–2000 plant accounting activity in the 2005 and 2013 depreciation reviews.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered predictive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each retirement unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted above, the database for Hydro One Networks contains plant accounting transactions for activity years 2000–2012. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[3] A similar limitation applies to the database of Hydro One Networks which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2012. With the exception of Account

[3]Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

1985 – Sentinel Lighting Rental Units, life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to an insufficient distribution of retirements over the available band of activity years.

As was noted in the 2005 review, limitations in conducting life analyses were also imposed by vintage years "banded" by the Company in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre–1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre–1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset categories recorded in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

CLASS/CATEGORY SERVICE LIVES

Class categories used in the 2013 review are those established in 2008 in preparation for implementation of International Financial Reporting Standards (IFRS). While Hydro One Networks has received an exemption from an otherwise mandatory adoption of IFRS for rate regulated entities, the Company intends to continue maintaining category classifications for engineering operations and business planning purposes.

The review of category lives undertaken in the current study included onsite meetings with Company engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates. Discussions were held with representatives from planning, operations, maintenance, information technology and facilities to assess the reasonableness of proposed category lives within their respective areas of expertise. Consideration was also given to the range of service lives recommended in the Asset Amortization Study prepared for the Ontario Energy Board by Kinectrics Inc.

USOA SERVICE LIVES

Proposed projection lives for USoA categories were derived from harmonic weighting of the constituent category lives recommended by the project team. Iowa survivor curves considered descriptive of the forces of retirement acting upon each USoA category were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Projection lives and projection curves recommended for all depreciable USoA categories are summarized in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has not been considered in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Networks at this time. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current review) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Distribution Operations (BU 220) on December 31, 2012. The recorded reserve was $2,851,239,959 or 36.4 percent of the depreciable plant investment. The corresponding computed reserve is $2,457,339,692 or 31.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $393,900,266 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

Statement C also provides a comparison of recorded, computed and rebalanced reserves for Common Operations (BU 300) on December 31, 2012. The recorded reserve was $339,476,788, or 50.8 percent of the depreciable plant investment. The corresponding computed reserve is $308,958,980 or 46.2 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $30,517,808 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2013 review were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Networks, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts and proposed for BU 220 is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves Hydro One Networks of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

Statements

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for Hydro One Networks Inc. Distribution and Common Operations. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2013 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2012.
- Statement D provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.
- Statement E displays the computation of proposed USoA projection lives derived from recommended Category ID lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Networks for the mix of investments recorded on December 31, 2012. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}.$$

Statements A through E

HYDRO ONE NETWORKS INC. (BU 220) Statement A

Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	2.16		9.36%	← 10 Year Amortization →			1.14%
Total Intangible Plant			9.36%	7.28		91.68%	1.14%
GENERATION PLANT							
1620 Buildings and Fixtures	19.18			8.21		89.97%	1.22%
1665 Fuel Holders, Producers and Accessories	28.79		1.36%	15.79		64.13%	2.27%
1675 Generators	16.69		1.18%	1.00		116.03%	-16.03%
1680 Accessory Electric Equpment	14.35			15.50		71.56%	1.83%
Total Generation Plant			1.16%	8.77		104.51%	-11.69%
DISTRIBUTION PLANT							
1805D Land - Depreciable			1.33%	6.92		101.23%	-0.18%
1806 Land Rights	60.09		1.22%	75.16		29.02%	0.94%
1808 Buildings and Fixtures	38.45		1.73%	33.17		39.61%	1.82%
1815 Transformer Station Equipment > 50 kV	30.02		1.98%	26.88		39.96%	2.23%
1820 Distribution Station Equipment < 50 kV	28.83		1.97%	17.79		51.88%	2.70%
1830 Poles, Towers and Fixtures	36.17		1.83%	40.14		31.89%	1.70%
1835 Overhead Conductors and Devices	27.08		2.14%	39.47		33.48%	1.69%
1840 Underground Conduit	29.49		1.97%	27.61		52.73%	1.71%
1845 Underground Conductors and Devices	10.79		3.53%	17.04		51.78%	2.83%
1850 Line Transformers	34.86		2.06%	29.42		32.17%	2.31%
1860 Meters	2.81		20.00%	17.68		13.55%	4.89%
1860S Meters (Sustainment)			6.67%	14.50		3.89%	6.63%
1555 Smart Meters			6.67%	11.77		25.16%	6.36%
1565 Smart Meters - Pilot			6.67%	9.01		41.64%	6.48%
Total Distribution Plant			2.44%	28.24		35.39%	2.27%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	28.59		2.08%	34.00		37.55%	1.84%
1910 Leasehold Improvements	4.28		7.94%	7.51		58.73%	5.50%
1922 Computer Hardware - Major	2.43		6.49%	2.79		110.65%	-3.82%
1955 Communication Equipment	4.04		9.01%	1.21		112.09%	-9.99%
1980 System Supervisory Equipment	9.57		8.01%	4.95		26.05%	14.94%
1985 Sentinel Lighting Rental Units	21.05		3.01%	18.81		44.69%	2.94%
Total Depreciable			5.27%	8.44		42.50%	5.73%
Amortizable							
1925 Computer Software - Major	2.16		9.36%	← 6 Year Amortization →			13.43%
Total Amortizable			9.36%	3.34		54.43%	13.43%
Total General Plant			6.53%	5.91		46.17%	8.10%
TOTAL DISTRIBUTION OPERATIONS			2.67%	24.16		36.35%	2.51%

HYDRO ONE NETWORKS INC. (BU 220) Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/12 Plant Investment	2013 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 67,475,909	$ 6,315,745	$ 770,815	$ (5,544,930)
Total Intangible Plant	$ 67,475,909	$ 6,315,745	$ 770,815	$ (5,544,930)
GENERATION PLANT				
1620 Buildings and Fixtures	$ 21,724	$ -	$ 265	$ 265
1665 Fuel Holders, Producers and Accessories	138,554	1,884	3,145	1,261
1675 Generators	537,296	6,340	(86,129)	(92,469)
1680 Accessory Electric Equipment	8,422		154	154
Total Generation Plant	$ 705,996	$ 8,224	$ (82,565)	$ (90,789)
DISTRIBUTION PLANT				
1805D Land - Depreciable	$ 41,368,892	$ 550,206	$ (74,464)	$ (624,670)
1806 Land Rights	231,262,773	2,821,406	2,173,870	(647,536)
1808 Buildings and Fixtures	6,908,747	119,521	125,739	6,218
1815 Transformer Station Equipment > 50 kV	145,807,990	2,886,998	3,251,518	364,520
1820 Distribution Station Equipment < 50 kV	432,624,382	8,522,700	11,680,858	3,158,158
1830 Poles, Towers and Fixtures	2,293,995,799	41,980,123	38,997,929	(2,982,194)
1835 Overhead Conductors and Devices	1,539,952,418	32,954,982	26,025,196	(6,929,786)
1840 Underground Conduit	22,741,027	447,998	388,872	(59,126)
1845 Underground Conductors and Devices	711,705,632	25,123,209	20,141,269	(4,981,940)
1850 Line Transformers	1,518,367,455	31,278,370	35,074,288	3,795,918
1860 Meters	12,239,718	2,447,944	598,522	(1,849,422)
1860S Meters (Sustainment)	3,433,912	229,042	227,668	(1,374)
1555 Smart Meters	478,072,877	31,887,461	30,405,435	(1,482,026)
1565 Smart Meters - Pilot	1,700,685	113,436	110,204	(3,232)
Total Distribution Plant	$ 7,440,182,307	$ 181,363,396	$ 169,126,904	$ (12,236,492)
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 99,299,073	$ 2,065,421	$ 1,827,103	$ (238,318)
1910 Leasehold Improvements	4,483,195	355,966	246,576	(109,390)
1922 Computer Hardware - Major	3,808,180	247,151	(145,472)	(392,623)
1955 Communication Equipment	22,963,244	2,068,988	(2,294,028)	(4,363,016)
1980 System Supervisory Equipment	89,188,567	7,144,004	13,324,772	6,180,768
1985 Sentinel Lighting Rental Units	13,085,670	393,879	384,719	(9,160)
Total Depreciable	$ 232,827,929	$ 12,275,409	$ 13,343,670	$ 1,068,261
Amortizable				
1925 Computer Software - Major	$ 103,491,657	$ 9,686,819	$ 13,903,240	$ 4,216,421
Total Amortizable	$ 103,491,657	$ 9,686,819	$ 13,903,240	$ 4,216,421
Total General Plant	$ 336,319,586	$ 21,962,228	$ 27,246,910	$ 5,284,682
TOTAL DISTRIBUTION OPERATIONS	$ 7,844,683,798	$ 209,649,593	$ 197,062,064	$ (12,587,529)

HYDRO ONE NETWORKS INC. (BU 220)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2012

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 67,475,909	$ 79,824,145	118.30%	$ 61,860,581	91.68%	$ 61,860,581	91.68%
Total Intangible Plant	$ 67,475,909	$ 79,824,145	118.30%	$ 61,860,581	91.68%	$ 61,860,581	91.68%
GENERATION PLANT							
1620 Buildings and Fixtures	$ 21,724	$ 21,724	100.00%	$ 16,728	77.00%	$ 19,545	89.97%
1665 Fuel Holders, Producers and Accessories	138,554	104,444	75.38%	76,046	54.89%	88,852	64.13%
1675 Generators	537,296	464,868	86.52%	533,582	99.31%	623,435	116.03%
1680 Accessory Electric Equpment	8,422	8,422	100.00%	5,158	61.25%	6,027	71.56%
Total Generation Plant	$ 705,996	$ 599,458	84.91%	$ 631,515	89.45%	$ 737,859	104.51%
DISTRIBUTION PLANT							
1805D Land - Depreciable	$ 41,368,892	$ 32,462,997	78.47%	$ 35,843,458	86.64%	$ 41,879,298	101.23%
1806 Land Rights	231,262,773	83,741,948	36.21%	57,445,673	24.84%	67,119,206	29.02%
1808 Buildings and Fixtures	6,908,747	2,409,656	34.88%	2,341,925	33.90%	2,736,292	39.61%
1815 Transformer Station Equipment > 50 kV	145,807,990	53,205,524	36.49%	49,863,834	34.20%	58,260,628	39.96%
1820 Distribution Station Equipment < 50 kV	432,624,382	164,678,110	38.06%	192,112,265	44.41%	224,462,906	51.88%
1830 Poles, Towers and Fixtures	2,293,995,799	769,195,636	33.53%	626,164,041	27.30%	731,606,597	31.89%
1835 Overhead Conductors and Devices	1,539,952,418	644,997,415	41.88%	441,219,194	28.65%	515,518,063	33.48%
1840 Underground Conduit	22,741,027	13,177,546	57.95%	10,263,289	45.13%	11,991,571	52.73%
1845 Underground Conductors and Devices	711,705,632	312,083,366	43.85%	315,383,280	44.31%	368,492,078	51.78%
1850 Line Transformers	1,518,367,455	437,140,946	28.79%	418,112,023	27.54%	488,519,772	32.17%
1860 Meters	12,239,718	9,030,347	73.78%	1,419,807	11.60%	1,658,895	13.55%
1860S Meters (Sustainment)	3,433,912	114,464	3.33%	114,464	3.33%	133,739	3.89%
1555 Smart Meters	478,072,877	101,033,247	21.13%	102,945,026	21.53%	120,280,398	25.16%
1565 Smart Meters - Pilot	1,700,685	(2,686,037)	-157.94%	606,173	35.64%	708,249	41.64%
Total Distribution Plant	$ 7,440,182,307	$ 2,620,585,164	35.22%	$ 2,253,834,452	30.29%	$ 2,633,367,691	35.39%

Statement C

HYDRO ONE NETWORKS INC. (BU 220)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2012

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 99,299,073	$ 39,998,189	40.28%	$ 31,910,481	32.14%	$ 37,284,029	37.55%
1910 Leasehold Improvements	4,483,195	3,355,573	74.85%	2,253,474	50.26%	2,632,946	58.73%
1922 Computer Hardware - Major	3,808,180	4,836,911	127.01%	3,606,494	94.70%	4,213,808	110.65%
1955 Communication Equipment	22,963,244	26,465,864	115.25%	22,028,963	95.93%	25,738,518	112.09%
1980 System Supervisory Equipment	89,188,567	12,739,221	14.28%	19,881,910	22.29%	23,229,913	26.05%
1985 Sentinel Lighting Rental Units	13,085,670	5,124,727	39.16%	5,004,861	38.25%	5,847,651	44.69%
Total Depreciable	$ 232,827,929	$ 92,520,483	39.74%	$ 84,686,181	36.37%	$ 98,946,865	42.50%
Amortizable							
1925 Computer Software - Major	$ 103,491,657	$ 57,710,708	55.76%	$ 56,326,963	54.43%	$ 56,326,963	54.43%
Total Amortizable	$ 103,491,657	$ 57,710,708	55.76%	$ 56,326,963	54.43%	$ 56,326,963	54.43%
Total General Plant	$ 336,319,586	$ 150,231,191	44.67%	$ 141,013,144	41.93%	$ 155,273,828	46.17%
TOTAL DISTRIBUTION OPERATIONS	$ 7,844,683,798	$ 2,851,239,959	36.35%	$ 2,457,339,692	31.32%	$ 2,851,239,959	36.35%

HYDRO ONE NETWORKS INC. (BU 220)
Current and Proposed Parameters
Vintage Group Procedure

Statement D

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	7.00	SQ	7.00	2.16			10.00	SQ	10.00	7.28		
Total Intangible Plant									10.00	7.28		
GENERATION PLANT												
1620 Buildings and Fixtures	50.00	SQ	50.00	19.18			35	S6	35.70	8.21		
1665 Fuel Holders, Producers and Accessories	40.00	SQ	40.00	28.79			35	S6	35.00	15.79		
1675 Generators	33.00	SQ	33.00	16.69			15	S6	144.68	1.00		
1680 Accessory Electric Equpment	39.00	SQ	38.73	14.35			40	S6	40.00	15.50		
Total Generation Plant									83.14	8.77		
DISTRIBUTION PLANT												
1805D Land - Depreciable	75.00	SQ	75.00				50.00	S6	51.81	6.92		
1806 Land Rights	77.00	SQ	77.00	60.09			100.00	S6	100.00	75.16		
1808 Buildings and Fixtures	53.00	S4	53.11	38.45			50.00	S4	50.18	33.17		
1815 Transformer Station Equipment > 50 kV	45.00	R4	45.21	30.02			40.00	R2.5	40.85	26.88		
1820 Distribution Station Equipment < 50 kV	44.00	R2.5	44.77	28.83			30.00	R2.5	32.00	17.79		
1830 Poles, Towers and Fixtures	50.00	S2	50.22	36.17			55.00	S2	55.21	40.14		
1835 Overhead Conductors and Devices	41.00	R3	41.51	27.08			55.00	S2	55.32	39.47		
1840 Underground Conduit	45.00	S2	45.13	29.49			50.00	S2	50.32	27.61		
1845 Underground Conductors and Devices	21.00	S3	22.08	10.79			30.00	S3	30.60	17.04		
1850 Line Transformers	45.00	R2	45.42	34.86			40.00	R2	40.60	29.42		
1860 Meters	5.00	SQ	5.00	2.81			20.00	R5	20.00	17.68		
1860S Meters (Sustainment)	15.00	SQ	15.00				15.00	R5	15.00	14.50		
1555 Smart Meters	15.00	SQ	15.00				15.00	R5	15.00	11.77		
1565 Smart Meters - Pilot	15.00	SQ	15.00				15.00	R5	14.00	9.01		
Total Distribution Plant									40.51	28.24		

HYDRO ONE NETWORKS INC. (BU 220)
Current and Proposed Parameters
Vintage Group Procedure

Statement D

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	44.00	S4	44.10	28.59			50.00	S4	50.10	34.00		
1910 Leasehold Improvements	10.00	SQ	10.00	4.28			10.00	S6	15.10	7.51		
1922 Computer Hardware - Major	9.00	SQ	9.00	2.43			10.00	S6	52.68	2.79		
1955 Communication Equipment	9.00	SQ	9.00	4.04			7.00	S6	29.74	1.21		
1980 System Supervisory Equipment	12.00	SQ	12.00	9.57			6.00	L2	6.37	4.95		
1985 Sentinel Lighting Rental Units	30.00	R1.5	30.82	21.05			30.00	R1.5	30.46	18.81		
Total Depreciable									13.26	8.44		
Amortizable												
1925 Computer Software - Major	7.00	SQ	7.00	2.16			6.00	SQ	6.00	3.34		
Total Amortizable									6.00	3.34		
Total General Plant									9.66	5.91		
TOTAL DISTRIBUTION OPERATIONS									34.83	24.16		

HYDRO ONE NETWORKS INC. (BU 220) Statement E
Asset Category Summary
December 31, 2012
Harmonic Weighting

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
INTANGIBLE PLANT						
1610 Computer Software						
1657 Genrl - Adm & Serv-Sys Software		7		10 a)		$ 67,475,909
Total USoA 1610	7 SQ	7	10 SQ	10	$ 67,475,909	$ 67,475,909
GENERATION PLANT						
1620 Buildings and Fixtures						
1712 Genx - Fsl-Yd Facilities		35		35		$ 15,914
1720 Genx - Fsl Rem-Bldg & Str		35		35		5,810
Total USoA 1620	50 SQ	35	35 S6	35	$ 21,724	$ 21,724
1665 Fuel Holders, Producers and Accessories						
1731 Genx - Fsl Rem-Fuel Handlng		35		35		$ 138,554
Total USoA 1665	40 SQ	35	35 S6	35	$ 138,554	$ 138,554
1675 Generators						
1756 Genx - Fsl-Ac Stndby Pwr		15		15		$ 468,592
1758 Genx - Fsl Rem Alt & Aux Gen		15		15		68,704
Total USoA 1675	33 SQ	15	15 S6	15	$ 537,296	$ 537,296
1680 Accessory Electric Eqpment						
1754 Genx - Fsl-Ele Aux Syst/Cab		40		40		$ 8,422
Total USoA 1680	39 SQ	40	40 S6	40	$ 8,422	$ 8,422
DISTRIBUTION PLANT						
1805D Land - Depreciable						
1113 Site Imprv - Excl Fence, Rd,Easmt		50		50		$ 68,598
1210 Land Purch & Acqui (Old Cap)		50		50		6,216,479
1310 Rural Lands < 1975		50		50		35,083,815
Total USoA 1805D	75 SQ	50	50 S6	50	$ 41,368,892	$ 41,368,892
1806 Land Rights						
1111 Rights & Easmnts <Landscaping>		100		100		$ 418,575
1212 Easmnts & Rights, Purch & Acqui		100		100		6,447,629
1215 Clrng & Overbldng		100		100		45,004,178
1311 Rural Intl Clring & Ovrbldg		100		100		177,842,134
1313 Rural Easements-Land Rights		100		100		1,536,161
1314 Rural Perm Rd & Surf Areas		25		25		14,095
Total USoA 1806	77 SQ	100	100 S6	100	$ 231,262,773	$ 231,262,773
1808 Buildings and Fixtures						
1112 Landscaping		50		50		$ 702,729
1120 Stn Buildings Components		50		50		3,781,547
1270 Serv Structures		100		50		2,250,042
1312 Rural Landscaping		50		50		174,429
Total USoA 1808	53 S4	60	50 S4	50	$ 6,908,747	$ 6,908,747
1815 Transformer Station Equipment > 50 kV						
1113 Site Imprv - Excl Fence, Rd,Easmt		50		50		$ 9,565,530
1122 Perm Rds & Surfc Area		25		25		1,558,780
1123 Cost Equip Foundations, Excav		60		50 e)		7,704,724
1127 Steel/Pipe Struc For Switch Eq		60		50		10,034,288
1128 Fences, Gates, Bldg		30		30		5,178,297
1150 Rot Elec Eqp (No Wind'G)		65		65		129,369
1152 Capacitors		35		35		17,456
1155 Regulators Incl Instal Cost		40		40		2,019,328
1160 Misc Stn Eqp -Trsf/Volt Trsf		40		40		12,196,052
1161 Serv Swg - Ac/Dc-Light Trsf		50		50		1,102,590
1162 Control Cable & Conduit		50		50		2,705,674
1163 Grounding Systems		50		50		5,265,967
1164 Metering Units		12		15 b)		5,680,263
1166 Switchboards		60		25 c)		1,056,887

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
1167 Sup Cntrl - Prim H/Ware & Sys		15		20 d)		1,085,306
1168 Sup Cntrl - Prim Appl S/Ware		15		20 d)		79,038
1170 Service Systems		50		50		80,312
1175 Transf <=50Kv or <5Mva		50		50		5,516,487
1176 Transf <=115Kv or >5Mva		50		50		35,703,801
1177 Transf <=230Kv		50		50		7,350,657
1179 Transf Instal Cost		50		50		5,956,570
1181 Switching >=34.5Kv		40		40		6,333,402
1182 Switching >=115Kv		40		50 b)		1,183,042
1184 Sf6 Switchgear		40		40		284,934
1185 Reclosers		40		40		8,937,961
1186 Misc Switching		40		50 b)		3,024,508
1187 Bus (Rigid & Strain)		40		50 e)		2,676,437
1188 Cable		40		40		2,113,876
1190 Cct Breakers >=230Kv		40		40		2,997
1191 Cct Breakers >=115Kv		40		40		604,788
1192 Cct Breakers <115Kv		40		40		540,039
1193 Cct Breakers Install		40		40		116,091
1194 Encld Swgr (All Compnt)		40		40		2,538
Total USoA 1815	45 R4	41	40 R2.5	42	$ 145,807,990	$ 145,807,990
1820 Distribution Station Equipment < 50 kV						
1113 Site Imprv - Excl Fence, Rd,Easmt		50		50		$ 18,219,025
1122 Perm Rds & Surfc Area		60		60		1,026,537
1123 Cost Equip Foundations, Excav		60		60		18,521,274
1127 Steel/Pipe Struc for Switch Eq		60		50 b)		21,884,466
1128 Fences, Gates, Bldg		30		50 b)		20,968,451
1150 Rot Elec Eqp (No Wind'G)		65		65		131,760
1152 Capacitors		35		35		79,520
1155 Regulators Incl Instal Cost		35		40 b)		12,551,154
1159 Mobile Sub-Stations		30		30		18,081,334
1160 Misc Stn Eqp - Trsf/Volt Trsf		35		40		39,554,417
1161 Serv Swg - Ac/Dc-Light Trsf		50		50		1,803,872
1162 Control Cable & Conduit		50		50		2,023,436
1163 Grounding Systems		50		50		12,238,925
1164 Metering Units		12		12		90,707,450
1166 Switchboards		60		25 c)		1,627,223
1167 Sup Cntrl - Prim H/Ware & Sys		15		15		2,175,165
1170 Service Systems		50		50		297,726
1173 Transf <=50Kv & >5Mva		35		50		63,242,974
1175 Transf <=50Kv or <5Mva		35		50		32,222,149
1179 Transf Instal Cost		50		50		21,030,164
1181 Switching >=34.5Kv		35		50 b)		13,931,998
1184 Sf6 Switchgear		35		35		1,768,586
1185 Reclosers		35		40		27,194,800
1186 Misc Switching		35		50 b)		3,320,110
1187 Bus (Rigid & Strain)		35		50 e)		1,058,992
1188 Cable		35		50		4,052,985
1192 Cct Breakers <115Kv		35		40		714,079
1193 Cct Breakers Install		35		40		117,683
1194 Encld Swgr (All Compnt)		35		40		2,078,128
Total USoA 1820	44 R2.5	26	30 R2.5	29	$ 432,624,382	$ 432,624,382
1830 Poles, Towers and Fixtures						
1230 Steel Twr, Sup & Ftng		95		75		$ 861,442
1240 Poles Incl Xarm, Guy, Anchr		55		55		529,707,051
1245 Steel Poles		75		75		3,731,015
1249 Composite Poles		95		80 d)		1,383,941
1340 Rural supports-Wood,Concret		55		55		1,752,488,127
1349 Steel Poles Support		75		75		5,824,223
Total USoA 1830	50 S2	55	55 S2	55	$ 2,293,995,799	$ 2,293,995,799

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
1835 Overhead Conductors and Devices						
1220 Insulators		45		45		$ 39,787,597
1232 Grounding System		45		45		1,006,619
1235 Opt Grnd Wire		50		50		2,906
1250 Overhd Conductor All		50		60 b)		325,813,756
1252 Switches & Devce		40		40		63,793,851
1320 Rural Switches/Load Interptr		40		40		114,163,656
1321 Rural Oil Sectnlzer & Reclsr Sw		40		40		26,714,919
1322 Rural Instalsectnlzr & Rclsr Sw		45		45		17,948,455
1330 Rural Conductor Prim & Sec Overh		50		60 b)		906,332,945
1376 Rural Voltage Regulators		40		40		24,122,917
1377 Rural Instl Vltge Regulators		40		40		8,813,810
1378 Rural Capacitors		40		40		8,035,619
1379 Rural Install Capacitors		40		40		3,415,370
Total USoA 1835	41 R3	48	55 S2	55	$ 1,539,952,418	$ 1,539,952,418
1840 Underground Conduit						
1261 Ugrd Conduit		50		50		$ 22,741,027
Total USoA 1840	45 S2	50	50 S2	50	$ 22,741,027	$ 22,741,027
1845 Underground Conductors and Devices						
1231 Condctr Submarine Cbl		30		30		$ 516,485
1262 Ugrd Conductor		30		30		14,071,923
1293 Ugrd Conductor Primary		30		30		7,546
1331 Rural Condctr Submarine Cbl		30		30		123,198,496
1393 Rural U/Grd Conductor-Prime		30		30		134,621,560
1394 Rural U/Grd Condr Sec Serv		30		30		406,602,557
1395 Rural U/Grd Fuse Housing		30		30		32,687,066
Total USoA 1845	21 S3	30	30 S3	30	$ 711,705,632	$ 711,705,632
1850 Line Transformers						
1255 Dx - Subtx Transformers		40		40		$ 735,282
1256 Dx - Subtx Trnsfmrs Install		40		40		1,982,149
1330 Rural Conductor Prim&Sec Overh		40		40		31,349
1341 Rural OH Trfrmrs <=25 Kva		40		40		333,166,444
1342 Rural OH Trfmrs >25 & <=50 Kva		40		40		114,856,997
1343 Rural OH Trfmrs >50 & <=75 Kva		40		40		38,953,826
1344 Rural OH Trfmr >75 & <=100 Kva		40		40		31,438,131
1345 Pole Top Trfs >100 & <=200 Kva		40		40		16,697,894
1346 Pole Top Trfs >200 & <=300 Kva		40		40		8,713,977
1347 Dx - Ptop Trfmrs >300 & <=500 Kva		40		40		1,059,089
1348 Dx - Pole Top Trfmrs >500 Kva		40		40		931,265
1351 Rural Trsf Instal		40		40		563,657,107
1385 Rural U/Grd Trsf 0-50Kva		40		40		97,624,444
1386 Rural U/Grd Trsf 51-75 Kva		40		40		26,359,271
1387 Rural U/Grd Trsf 76-100 Kva		40		40		40,854,320
1388 Rural U/Grd Trsf 101-200Kva		40		40		17,161,327
1389 Rural U/Grd Trsf 201-300Kva		40		40		21,291,047
1390 Rural U/Grd Trsf 301-500Kva		40		40		33,260,592
1391 Rural U/Grd Trsf 501-750Kva		40		40		5,914,649
1392 Rural U/Grd Trsf >750Kva		40		40		10,231,925
1396 Rural U/Grd Trfrmrs Instal		40		40		153,446,372
Total USoA 1850	45 R2	40	40 R2	40	$ 1,518,367,455	$ 1,518,367,455
1860 Meters						
1356 Meters - Watthour, Single Ph		5		20 f)		$ 2,833,486
1357 Meters - Demand, Single Ph		5		20 f)		1,694,397
1358 Metering Polyphase		5		20 f)		628,847
1361 Install - W/Hr & Dmd M S Ph		5		20 f)		6,633,142
1362 Install - Meters Polyphase		5		20 f)		449,845
Total USoA 1860	5 SQ	5	20 R5	20	$ 12,239,718	$ 12,239,718

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
1860S Meters (Sustainment)						
1365 Smart Mtr - Incl Cost & Inst		15		15		$ 3,433,912
Total USoA 1860S	15 SQ	15	15 R5	15	$ 3,433,912	$ 3,433,912
1555 Smart Meters						
1365 Smart Mtr - Incl Cost & Inst		15		15		$ 478,072,877
Total USoA 1555	15 SQ	15	15 R5	15	$ 478,072,877	$ 478,072,877
1565 Smart Meters - Pilot						
1365 Smart Mtr - Incl Cost & Inst		15		15		$ 1,700,685
Total USoA 1565	15 SQ	15	15 R5	15	$ 1,700,685	$ 1,700,685
GENERAL PLANT						
Depreciable						
1908 Buildings and Fixtures						
1612 Genrl - Adm & Serv-Landscaping		50		50		$ 38,335
1621 Genrl - Adm & Serv Bld Frame & Mtl		50		50		50,377,914
1622 Genrl - Adm & Serv-Rds & Surfaces		50		50		6,287,096
1623 Genrl - Adm & Serv-Bld Frame		50		50		29,016,576
1628 Genrl - Adm & Serv-Fence,Gate		30		30		1,521,769
1650 Genrl - Adm & Serv-Distn Sys		50		50		1,878,814
1663 Genrl - Adm & Serv Aux Eq Bld		50		50		10,178,569
Total USoA 1908	44 S4	49	50 S4	49	$ 99,299,073	$ 99,299,073
1910 Leasehold Improvements						
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10		$ 4,483,195
Total USoA 1910	10 SQ	10	10 S6	10	$ 4,483,195	$ 4,483,195
1922 Computer Hardware - Major						
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10		$ 1,110,059
1655 Genrl - Adm & Serv-Lan Cable		10		10		2,290,724
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10		161,333
1657 Genrl - Adm & Serv-Sys Software		10		10		246,063
Total USoA 1922	9 SQ	10	10 S6	10	$ 3,808,180	$ 3,808,180
1955 Communication Equipment						
1654 Genrl - Adm & Serv-Telcm Wire		7		7		$ 7,108,308
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10		117,949
1658 Genrl - Adm & Serv-Telcm Equip		7		7		11,215,773
1659 Genrl - Adm & Serv-Telcom Sw		7		7		186,059
1850 Genrl - Comm Radio Equipment		10		10		3,695,214
1854 Genrl - Comm Admin Telcom Equp		7		7		596,112
1863 Genrl - Comm Optical Wire		25		25		40,856
1870 Genrl - Comm Power Supply Equp		15		15		2,972
Total USoA 1955	9 SQ	7	7 S6	7	$ 22,963,244	$ 22,963,244
1980 System Supervisory Equipment						
1840 Genrl - Comm Pwr Line Equip		15		15		$ 138,912
1844 Genrl - Comm Sys Cntrl Comp Eq		7		6 g)		3,642,616
1847 Genrl - Comm Dacs Sys S/Ware		15		6 g)		85,406,762
1860 Genrl - Comm Pole Comm Cab Bths		25		25		277
Total USoA 1980	12 SQ	14	6 L2	6	$ 89,188,567	$ 89,188,567
1985 Sentinel Lighting Rental Units						
1374 Genrl - Dist Sentnal Lite Units		30		30		$ 13,085,670
Total USoA 1985	30 R1.5	30	30 R1.5	30	$ 13,085,670	$ 13,085,670
Amortizable						
1925 Computer Software - Major						
1657 Genrl - Adm & Serv-Sys Software		7		6 g)		$ 103,491,657
Total USoA 1925	7 SQ	7	6 SQ	6	$ 103,491,657	$ 103,491,657
TOTAL BU 220					$ 7,844,683,798	$ 7,844,683,798

a) To align with BU 210 (Tx) and BU 300 (Common).
b) To align with Kinectrics.
c) Based on life span of newer equipment.
d) To be consistent with BU 210 (Tx).
e) To align with transformers. Cost effective to replace both.
f) Analog meters, continuing investments.
g) To align with hardware/software refresh policy.

Statements A through E

HYDRO ONE NETWORKS INC. - (BU 300)
Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	3.63		9.28%	← 10 Year Amortization →			9.28%
Total Intangible Plant			9.28%	6.18		41.96%	9.28%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	33.76		1.00%	32.73		58.88%	1.26%
1910 Leasehold Improvements	1.98		-33.36%	2.79		128.50%	-10.22%
1922 Computer Equipment - Hardware	1.55		-64.94%	9.35		30.50%	7.43%
1955 Communication Equipment	2.39		-30.02%	1.41		156.05%	-39.75%
1980 System Supervisory Equipment	1.00		-86.35%	1.00		157.57%	-57.57%
Total Depreciable			-11.33%	15.56		76.59%	-5.29%
Amortizable							
1915 Office Furniture and Equipment	← 7 Year Amortization →		13.80%	← 7 Year Amortization →			13.80%
1920 Computer Hardware - Minor	← 5 Year Amortization →		18.32%	← 5 Year Amortization →			18.32%
1925 Computer Software - Major	6.92		9.40%	← 6 Year Amortization →			10.22%
1935 Stores Equipment	← 8 Year Amortization →		11.30%	← 8 Year Amortization →			11.30%
1940 Tools, Shop and Garage Equipment	← 6 Year Amortization →		15.29%	← 6 Year Amortization →			15.29%
1945 Measurement and Testing Equipment	← 5 Year Amortization →		18.70%	← 5 Year Amortization →			18.70%
1960 Miscellaneous Equipment	← 5 Year Amortization →		17.63%	← 5 Year Amortization →			17.63%
Total Amortizable			14.48%	2.89		54.23%	14.79%
Total General Plant			6.28%	3.94		61.34%	8.41%
TOTAL COMMON OPERATIONS			7.91%	4.99		50.76%	8.88%

HYDRO ONE NETWORKS INC. - (BU 300) Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/12 Plant Investment	2013 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 365,119,221	$ 33,865,737	$ 33,865,737	$ -
Total Intangible Plant	$ 365,119,221	$ 33,865,737	$ 33,865,737	$ -
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 70,409,754	$ 704,098	$ 887,163	$ 183,065
1910 Leasehold Improvements	9,682,409	(3,230,052)	(989,542)	2,240,510
1922 Computer Equipment - Hardware	4,516,374	(2,932,933)	335,567	3,268,500
1955 Communication Equipment	8,554,760	(2,568,139)	(3,400,517)	(832,378)
1980 System Supervisory Equipment	3,366,771	(2,907,207)	(1,938,250)	968,957
Total Depreciable	$ 96,530,068	$ (10,934,233)	$ (5,105,579)	$ 5,828,654
Amortizable				
1915 Office Furniture and Equipment	$ 8,744,606	$ 1,206,469	$ 1,206,469	$ -
1920 Computer Hardware - Minor	89,152,467	16,329,365	16,329,365	
1925 Computer Software - Major	79,072,023	7,434,939	8,083,886	648,947
1935 Stores Equipment	3,585,824	405,212	405,212	
1940 Tools, Shop and Garage Equipment	8,304,364	1,270,059	1,270,059	
1945 Measurement and Testing Equipment	11,792,701	2,205,421	2,205,421	
1960 Miscellaneous Equipment	6,508,693	1,147,221	1,147,221	
Total Amortizable	$ 207,160,678	$ 29,998,686	$ 30,647,633	$ 648,947
Total General Plant	$ 303,690,746	$ 19,064,453	$ 25,542,054	$ 6,477,601
TOTAL COMMON OPERATIONS	$ 668,809,967	$ 52,930,190	$ 59,407,791	$ 6,477,601

Statement C

HYDRO ONE NETWORKS INC. - (BU 300)
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2012

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 365,119,221	$ 170,469,173	46.69%	$ 153,190,721	41.96%	$ 153,190,721	41.96%
Total Intangible Plant	$ 365,119,221	$ 170,469,173	46.69%	$ 153,190,721	41.96%	$ 153,190,721	41.96%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 70,409,754	$ 29,573,987	42.00%	$ 24,347,167	34.58%	$ 41,460,694	58.88%
1910 Leasehold Improvements	9,682,409	8,538,767	88.19%	7,306,514	75.46%	12,442,235	128.50%
1922 Computer Equipment - Hardware	4,516,374	826,663	18.30%	808,903	17.91%	1,377,477	30.50%
1955 Communication Equipment	8,554,760	8,230,558	96.21%	7,839,326	91.64%	13,349,558	156.05%
1980 System Supervisory Equipment	3,366,771	5,116,173	151.96%	3,115,332	92.53%	5,305,086	157.57%
Total Depreciable	$ 96,530,068	$ 52,286,149	54.17%	$ 43,417,242	44.98%	$ 73,935,050	76.59%
Amortizable							
1915 Office Furniture and Equipment	$ 8,744,606	$ 4,520,083	51.69%	$ 4,525,746	51.75%	$ 4,525,746	51.75%
1920 Computer Hardware - Minor	89,152,467	38,738,817	43.45%	39,782,809	44.62%	39,782,809	44.62%
1925 Computer Software - Major	79,072,023	58,375,800	73.83%	52,907,562	66.91%	52,907,562	66.91%
1935 Stores Equipment	3,585,824	2,520,667	70.30%	2,500,200	69.72%	2,500,200	69.72%
1940 Tools, Shop and Garage Equipment	8,304,364	3,676,673	44.27%	3,645,527	43.90%	3,645,527	43.90%
1945 Measurement and Testing Equipment	11,792,701	5,088,118	43.15%	5,172,517	43.86%	5,172,517	43.86%
1960 Miscellaneous Equipment	6,508,693	3,801,308	58.40%	3,816,656	58.64%	3,816,656	58.64%
Total Amortizable	$ 207,160,678	$ 116,721,466	56.34%	$ 112,351,017	54.23%	$ 112,351,017	54.23%
Total General Plant	$ 303,690,746	$ 169,007,615	55.65%	$ 155,768,259	51.29%	$ 186,286,067	61.34%
TOTAL COMMON OPERATIONS	$ 668,809,967	$ 339,476,788	50.76%	$ 308,958,980	46.20%	$ 339,476,788	50.76%

HYDRO ONE NETWORKS INC. - (BU 300)
Current and Proposed Parameters
Vintage Group Procedure

Statement D

Account Description	Current Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	10.00	SQ	10.00	3.63			10.00	SQ	10.00	6.18		
Total Intangible Plant									10.00	6.18		
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	50.00	S4	50.01	33.76			50.00	S4	50.03	32.73		
1910 Leasehold Improvements	10.00	S6	10.58	1.98			10.00	S6	11.37	2.79		
1922 Computer Equipment - Hardware	10.00	S6	87.20	1.55			10.00	S6	11.39	9.35		
1955 Communication Equipment	7.00	S6	15.00	2.39			7.00	S6	16.86	1.41		
1980 System Supervisory Equipment	7.00	S6	11.39	1.00			7.00	S6	13.39	1.00		
Total Depreciable									28.27	15.56		
Amortizable												
1915 Office Furniture and Equipment	7.00	SQ	7.00	4.01			7.00	SQ	7.00	3.38		
1920 Computer Hardware - Minor	5.00	SQ	5.00	2.44			5.00	SQ	5.00	2.77		
1925 Computer Software - Major	10.00	SQ	7.00	6.92			6.00	SQ	6.00	3.06		
1935 Stores Equipment	8.00	SQ	8.00	2.86			8.00	SQ	8.00	2.42		
1940 Tools, Shop and Garage Equipment	6.00	SQ	6.00	2.80			6.00	SQ	6.00	3.37		
1945 Measurement and Testing Equipment	5.00	SQ	5.00	2.64			5.00	SQ	5.00	2.81		
1960 Miscellaneous Equipment	5.00	SQ	5.00	2.55			5.00	SQ	5.00	2.07		
Total Amortizable									5.49	2.89		
Total General Plant									7.38	3.94		
TOTAL COMMON OPERATIONS									8.61	4.99		

HYDRO ONE NETWORKS INC. - (BU 300) Statement E

Asset Category Summary
December 31, 2012
Harmonic Weighting

Description	Current P-Life USoA	Current P-Life Category	Proposed P-Life USoA	Proposed P-Life Category	Plant USoA	Plant Category
A	B	C	D	E	F	G
INTANGIBLE PLANT						
1610 Computer Software						
1657 Genrl - Adm & Serv-Sys Software		10		10		$ 365,119,221
Total USoA 1610	10 SQ	10	10 SQ	10	$ 365,119,221	$ 365,119,221
GENERAL PLANT						
Depreciable						
1908 Buildings and Fixtures						
1621 Genrl - Adm & Serv-Bld Frame&Mtl		50		50		$ 41,070,808
1622 Genrl - Adm & Serv-Rds&Surfaces		25		25		1,485,662
1623 Genrl - Adm & Serv-Bld Frame		50		50		9,414,683
1628 Genrl - Adm & Serv-Fence,Gate		30		30		960,151
1650 Genrl - Adm & Serv-Distn Sys		50		50		565,380
1663 Genrl - Adm & Serv-Aux Eq Bld		50		50		10,146,899
1820 Genrl - Comm-Buildings		50		50		6,766,170
Total USoA 1908	50 S4	49	50 S4	49	$ 70,409,754	$ 70,409,754
1910 Leasehold Improvements						
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10		$ 9,682,409
Total USoA 1910	10 S6	10	10 S6	10	$ 9,682,409	$ 9,682,409
1922 Computer Equipment - Hardware						
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10		$ 4,011,018
1655 Genrl - Adm & Serv-Lan Cable		10		10		505,356
Total USoA 1922	10 S6	10	10 S6	10	$ 4,516,374	$ 4,516,374
1955 Communication Equipment						
1654 Genrl - Adm & Serv-Telcm Wire		7		7		$ 2,272,521
1658 Genrl - Adm & Serv-Telcm Equip		7		7		1,837,766
1850 Genrl - Comm-Radio Equipment		10		10		11,318
1854 Genrl - Comm-Admin Telcom Equp		7		7		4,433,155
Total USoA 1955	7 S6	7	7 S6	7	$ 8,554,760	$ 8,554,760
1980 System Supervisory Equipment						
1840 Genrl - Comm-Pwr Line Equip		15		15		$ 389,017
1844 Genrl - Comm-Sys Cntrl Comp Eq		7		6 a)		2,977,754
Total USoA 1980	7 S6	7	7 S6	6	$ 3,366,771	$ 3,366,771
Amortizable						
1915 Office Furniture and Equipment						
S007 Mfa - 7 Yr Sl		7		7		$ 8,744,606
Total USoA 1915	7 SQ	7	7 SQ	7	$ 8,744,606	$ 8,744,606
1920 Computer Hardware - Minor						
S005 Computers - 40% Db (Default)		5		5		$ 89,152,467
Total USoA 1920	5 SQ	5	5 SQ	5	$ 89,152,467	$ 89,152,467
1925 Computer Software - Major						
1657 Genrl - Adm & Serv-Sys Software		10		6 a)		$ 79,072,023
Total USoA 1925	10 SQ	10	6 SQ	6	$ 79,072,023	$ 79,072,023
1935 Stores Equipment						
S008 Mfa - 8Yr Sl(Def)		8		8		$ 3,585,824
Total USoA 1935	8 SQ	8	8 SQ	8	$ 3,585,824	$ 3,585,824
1940 Tools, Shop and Garage Equipment						
S006 Mfa - 6Yr Sl(Def)		6		6		$ 8,304,364
Total USoA 1940	6 SQ	6	6 SQ	6	$ 8,304,364	$ 8,304,364
1945 Measurement and Testing Equipment						
S005 Mfa - 5Yr Sl(Def)		5		5		$ 11,792,701
Total USoA 1945	5 SQ	5	5 SQ	5	$ 11,792,701	$ 11,792,701
1960 Miscellaneous Equipment						
S005 Mfa - 5Yr Sl(Def)		5		5		$ 6,508,693
Total USoA 1960	5 SQ	5	5 SQ	5	$ 6,508,693	$ 6,508,693
TOTAL BU 300					$ 668,809,967	$ 668,809,965

a) To align with hardware/software refresh policy.

Analysis

SECTION IV

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Networks distribution and common depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1850 – Line Transformers. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Networks review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis; and

Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 4. Generation Arrangement

Schedule B – Age Distribution

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

Schedule C – Plant History

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant
Account: 1850 Line Transformers

Dispersion: 40 - R2
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2012 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2012	0.5	82,690,555	40.00	39.55	0.9887	1.0000	81,754,695	2,067,239
2011	1.5	84,467,355	40.00	38.65	0.9661	1.0000	81,606,724	2,111,591
2010	2.5	91,255,439	40.00	37.75	0.9437	1.0000	86,119,886	2,281,135
2009	3.5	81,884,862	40.00	36.87	0.9216	1.0000	75,465,434	2,047,045
2008	4.5	79,226,505	39.96	35.98	0.9006	1.0000	71,348,096	1,982,724
2007	5.5	76,998,314	40.02	35.11	0.8774	1.0000	67,560,399	1,924,172
2006	6.5	82,154,915	40.00	34.25	0.8561	1.0000	70,330,714	2,053,736
2005	7.5	67,921,573	40.04	33.39	0.8339	1.0000	56,638,089	1,696,427
2004	8.5	72,183,745	40.03	32.54	0.8127	1.0000	58,662,738	1,803,025
2003	9.5	57,248,938	40.05	31.69	0.7914	1.0000	45,306,035	1,429,534
2002	10.5	54,628,618	39.96	30.86	0.7722	1.0000	42,185,951	1,367,086
2001	11.5	39,927,999	40.02	30.03	0.7504	1.0000	29,962,970	997,697
2000	12.5	37,276,529	39.92	29.21	0.7319	1.0000	27,281,987	933,844
1999	13.5	53,003,068	39.74	28.41	0.7148	1.0000	37,886,157	1,333,736
1998	14.5	31,176,723	39.99	27.61	0.6904	1.0000	21,523,752	779,665
1997	15.5	23,538,662	40.10	26.82	0.6687	1.0000	15,739,381	586,934
1996	16.5	20,916,364	40.12	26.04	0.6489	1.0000	13,572,825	521,318
1995	17.5	18,395,035	40.22	25.26	0.6281	1.0000	11,554,826	457,352
1994	18.5	16,446,146	40.33	24.50	0.6076	1.0000	9,992,338	407,786
1993	19.5	15,454,356	40.41	23.75	0.5878	1.0000	9,084,164	382,439
1992	20.5	28,534,057	40.68	23.01	0.5657	1.0000	16,141,971	701,420
1991	21.5	32,686,791	40.69	22.28	0.5477	1.0000	17,902,286	803,374
1990	22.5	45,381,825	40.87	21.57	0.5277	1.0000	23,946,905	1,110,416
1989	23.5	43,634,769	41.04	20.86	0.5083	1.0000	22,179,093	1,063,300
1988	24.5	45,688,999	41.16	20.16	0.4899	1.0000	22,383,074	1,110,084
1987	25.5	33,443,472	41.35	19.48	0.4712	1.0000	15,756,918	808,878
1986	26.5	27,950,665	41.49	18.81	0.4533	1.0000	12,671,094	673,683
1985	27.5	23,167,988	41.56	18.15	0.4367	1.0000	10,118,186	557,482
1984	28.5	14,883,759	41.85	17.50	0.4182	1.0000	6,224,674	355,623
1983	29.5	13,860,101	42.17	16.87	0.4000	1.0000	5,544,547	328,652
1982	30.5	13,262,448	42.14	16.25	0.3857	1.0000	5,114,906	314,749
1981	31.5	11,500,634	42.60	15.64	0.3673	1.0000	4,223,791	269,989
1980	32.5	8,171,880	42.57	15.05	0.3536	1.0000	2,889,260	191,952
1979	33.5	7,070,570	42.83	14.47	0.3379	1.0000	2,389,334	165,082
1978	34.5	6,661,867	43.22	13.91	0.3218	1.0000	2,144,119	154,148
1977	35.5	7,624,665	43.71	13.36	0.3057	1.0000	2,330,650	174,450
1976	36.5	7,548,364	44.02	12.83	0.2913	1.0000	2,198,955	171,457

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant
Account: 1850 Line Transformers

Dispersion: 40 - R2
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2012 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1975	37.5	9,096,435	44.27	12.30	0.2779	1.0000	2,528,320	205,472
1974	38.5	8,484,452	44.63	11.80	0.2644	1.0000	2,243,457	190,128
1973	39.5	5,189,776	45.27	11.31	0.2498	1.0000	1,296,432	114,633
1972	40.5	3,434,136	45.48	10.83	0.2382	1.0000	818,135	75,515
1971	41.5	3,834,595	46.05	10.37	0.2253	1.0000	863,889	83,277
1970	42.5	10,051,085	46.20	9.93	0.2149	1.0000	2,159,749	217,544
1965	47.5	3,829,162	49.08	7.91	0.1612	1.0000	617,216	78,020
1960	52.5	16,579,258	52.72	6.20	0.1176	1.0000	1,949,360	314,471
Total	13.3	$1,518,367,455	40.60	29.42	0.7246	1.0000	$1,100,213,484	$37,398,281

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

Age Distribution

Vintage	Age as of 12/31/2012	Derived Additions	2000 Opening Balance	Experience to 12/31/2012 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2012	0.5	82,695,658		82,690,555	0.9999	0.5000
2011	1.5	84,580,768		84,467,355	0.9987	1.4988
2010	2.5	91,708,938		91,255,439	0.9951	2.4963
2009	3.5	82,593,262		81,884,862	0.9914	3.4854
2008	4.5	81,255,653		79,226,505	0.9750	4.4313
2007	5.5	77,690,753		76,998,314	0.9911	5.4747
2006	6.5	83,580,441		82,154,915	0.9829	6.4429
2005	7.5	68,719,603		67,921,573	0.9884	7.4562
2004	8.5	73,473,306		72,183,745	0.9824	8.4267
2003	9.5	58,213,133		57,248,938	0.9834	9.4083
2002	10.5	56,593,207		54,628,618	0.9653	10.2851
2001	11.5	41,132,760		39,927,999	0.9707	11.3043
2000	12.5	39,442,872		37,276,529	0.9451	12.1546
1999	13.5		57,272,447	53,003,068	0.9255	12.9248
1998	14.5		32,863,199	31,176,723	0.9487	14.1125
1997	15.5		24,669,816	23,538,662	0.9541	15.1632
1996	16.5		22,117,521	20,916,364	0.9457	16.1071
1995	17.5		19,347,143	18,395,035	0.9508	17.1241
1994	18.5		17,294,015	16,446,146	0.9510	18.1435
1993	19.5		16,256,159	15,454,356	0.9507	19.1240
1992	20.5		29,320,674	28,534,057	0.9732	20.2855
1991	21.5		34,125,421	32,686,791	0.9578	21.1730
1990	22.5		47,194,052	45,381,825	0.9616	22.2254
1989	23.5		45,170,692	43,634,769	0.9660	23.2519
1988	24.5		47,646,128	45,688,999	0.9589	24.2193
1987	25.5		34,720,036	33,443,472	0.9632	25.2401
1986	26.5		29,077,246	27,950,665	0.9613	26.2036
1985	27.5		24,645,406	23,167,988	0.9401	27.0778
1984	28.5		15,625,603	14,883,759	0.9525	28.1622
1983	29.5		14,371,055	13,860,101	0.9644	29.2560
1982	30.5		14,333,262	13,262,448	0.9253	29.9770
1981	31.5		12,115,442	11,500,634	0.9493	31.1762
1980	32.5		8,928,755	8,171,880	0.9152	31.8724
1979	33.5		7,716,587	7,070,570	0.9163	32.8314
1978	34.5		7,263,646	6,661,867	0.9172	33.8987
1977	35.5		8,142,806	7,624,665	0.9364	35.0472
1976	36.5		8,054,793	7,548,364	0.9371	36.0020
1975	37.5		9,908,724	9,096,435	0.9180	36.8619

HYDRO ONE NETWORKS INC. - DISTRIBUTION
Distribution Plant
Account: 1850 Line Transformers

Age Distribution

Vintage	Age as of 12/31/2012	Derived Additions	2000 Opening Balance	Experience to 12/31/2012 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1974	38.5		9,331,390	8,484,452	0.9092	37.8060
1973	39.5		5,518,893	5,189,776	0.9404	39.0195
1972	40.5		3,782,786	3,434,136	0.9078	39.7630
1971	41.5		4,216,289	3,834,595	0.9095	40.8471
1970	42.5		11,496,286	10,051,085	0.8743	41.4912
1965	47.5		4,532,985	3,829,162	0.8447	46.4009
1960	52.5		19,526,173	16,579,258	0.8491	51.4104
Total	13.3	$921,680,354	$646,585,428	$1,518,367,455	0.9682	

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	833,030,256	16,511,195	2,159,339	34,271,760	881,653,873
2001	881,653,873	8,557,059	2,686,174	96,233,636	983,758,394
2002	983,758,394	6,144,671	6,564,516	127,964,395	1,111,302,944
2003	1,111,302,944	7,982,518	4,950,154	66,204,802	1,180,540,110
2004	1,180,540,110	7,658,134	4,869,058	98,451,464	1,281,780,651
2005	1,281,780,651	4,179,746	5,002,138	95,646,532	1,376,604,791
2006	1,376,604,791	3,979,215	3,497,726	103,498,367	1,480,584,647
2007	1,480,584,647	3,477,676	2,089,879	(369,341,975)	1,112,630,469
2008	1,112,630,469	627,238	2,124,214	84,447,833	1,195,581,326
2009	1,195,581,326	84,406,753	3,686,551	(3,057,850)	1,273,243,677
2010	1,273,243,677	81,167,048	4,318,539		1,350,092,186
2011	1,350,092,186	89,916,228	4,492,069	(29,401)	1,435,486,944
2012	1,435,486,944	86,408,054	3,457,971	(69,573)	1,518,367,455

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	841,991,482	42,882,092	2,159,339	1,250,760	883,964,995
2001	883,964,995	56,642,405	2,686,174	53,660,221	991,581,447
2002	991,581,447	75,154,353	6,564,516	52,728,737	1,112,900,021
2003	1,112,900,021	74,702,255	4,950,154	(36,339)	1,182,615,783
2004	1,182,615,783	100,277,260	4,869,058	(26,745)	1,277,997,241
2005	1,277,997,241	96,095,905	5,002,138	2,612,348	1,371,703,355
2006	1,371,703,355	83,718,539	3,497,726	11,790	1,451,935,958
2007	1,451,935,958	77,809,601	2,089,879	(413,803,469)	1,113,852,211
2008	1,113,852,211	81,283,690	2,124,214		1,193,011,686
2009	1,193,011,686	82,593,251	3,686,551	(267,729)	1,271,650,658
2010	1,271,650,658	91,708,928	4,318,539		1,359,041,047
2011	1,359,041,047	84,501,538	4,492,069	79,251	1,439,129,768
2012	1,439,129,768	82,695,658	3,457,971		1,518,367,455

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	70.9	84.3	L0.5	2.08	55.9	R2	0.80	100.3	O3 *	0.44
2001-2005	69.2	82.8	L0.5	2.18	55.9	R2	0.74	78.0	O3 *	0.49
2002-2006	70.2	87.8	L0.5	2.20	58.5	R2	0.77	62.8	L2 *	0.67
2003-2007	73.5	93.2	L0.5	1.65	62.5	R2	0.37	60.1	R2	0.46
2004-2008	75.8	98.6	L0.5	1.42	66.2	S1.5	0.31	61.5	R2.5	0.42
2005-2009	78.1	109.9	S-.5	1.36	70.0	S1.5	0.31	66.1	R2.5	0.34
2006-2010	79.4	120.6	S-.5	1.47	72.9	R2	0.41	71.9	R2	0.42
2007-2011	78.2	117.1	S-.5	1.35	73.6	R2	0.40	70.6	R2	0.41
2008-2012	79.1	122.9	S-.5	1.19	79.5	S1	0.49	80.8	S1	0.49

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2012	73.6	104.8	L0.5	1.88	69.2	S1	0.53	101.5	O3 *	0.51
2002-2012	73.7	104.3	L0.5	1.75	69.4	S1	0.49	84.2	L0.5 *	0.48
2004-2012	76.5	110.5	S-.5	1.41	73.3	S1	0.37	72.7	R2	0.37
2006-2012	78.9	119.4	S-.5	1.28	76.9	S1	0.38	73.5	R2	0.38
2008-2012	79.1	122.9	S-.5	1.19	79.5	S1	0.49	80.8	S1	0.49
2010-2012	82.0	124.1	SC	0.43	85.3	R1.5	0.45	76.7	R2	0.39
2012-2012	87.1	122.4	S-.5	0.82	109.7	S0	0.88	90.3	R2	0.85

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None
Placement Band: 1960-2012
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	87.7	111.0	S-.5	0.52	66.7	R2	0.94	162.6	R1 *	1.39
2000-2003	74.7	87.1	L0.5	1.21	56.0	R2	0.58	116.4	O3 *	0.63
2000-2005	70.2	85.7	L0.5	2.24	57.1	R2	0.85	86.7	O3 *	0.61
2000-2007	72.0	92.0	L0.5	1.91	60.8	R2	0.42	62.2	S1	0.39
2000-2009	73.3	97.8	L0.5	1.76	63.8	R2	0.29	72.6	L1.5 *	0.29
2000-2011	72.9	102.8	L0.5	1.97	66.9	R2	0.51	82.5	L0.5 *	0.49
2000-2012	73.6	104.8	L0.5	1.88	69.2	S1	0.53	101.5	O3 *	0.51

HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

T-Cut: None

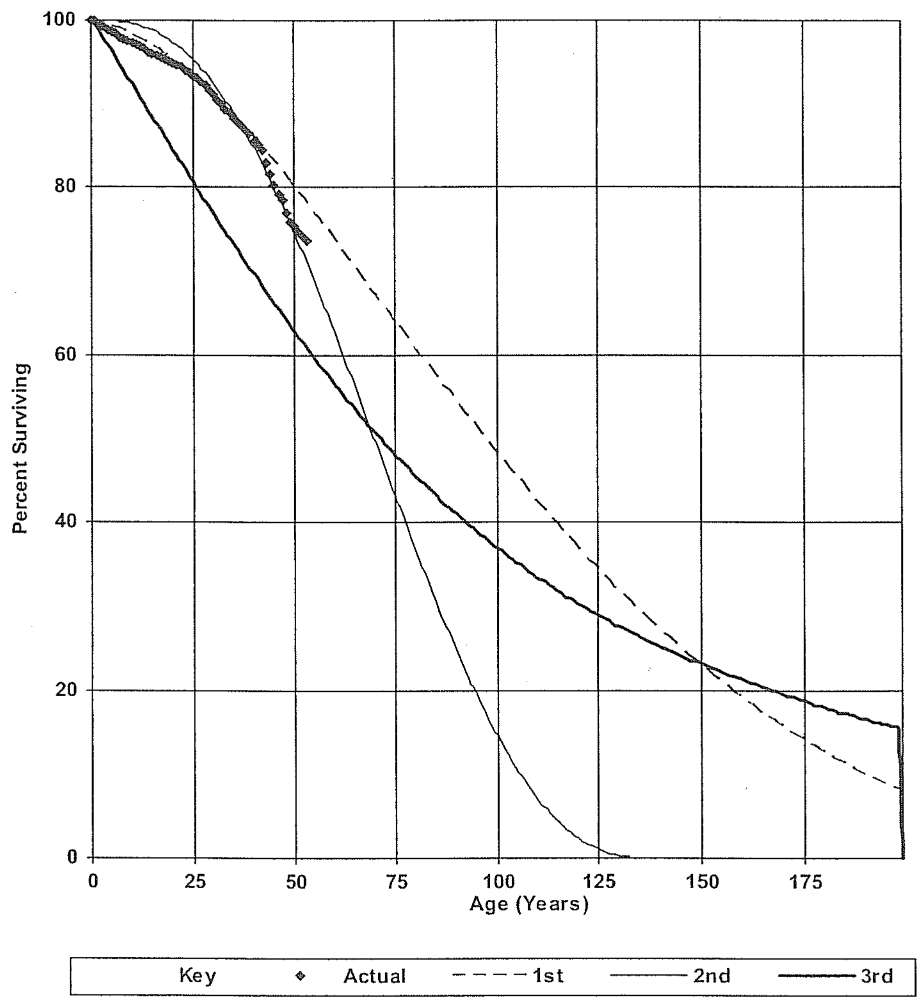
Placement Band: 1960-2012 Observation Band: 2000-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 104.8-L0.5 2nd: 69.2-S1 3rd: 101.5-O3



HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

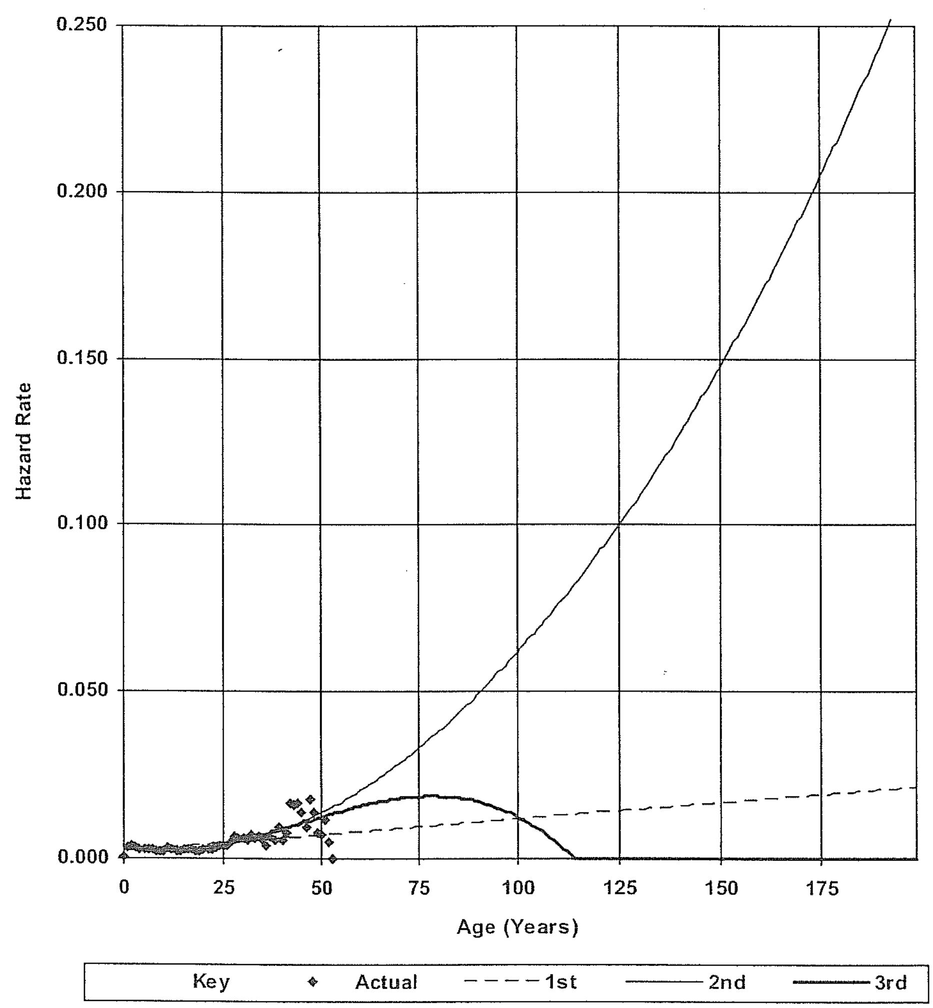
T-Cut: None

Placement Band: 1960-2012 Observation Band: 2000-2012

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function 1st: 104.8-L0.5 2nd: 69.2-S1 3rd: 101.5-O3



HYDRO ONE NETWORKS INC. - DISTRIBUTION

Distribution Plant

Account: 1850 Line Transformers

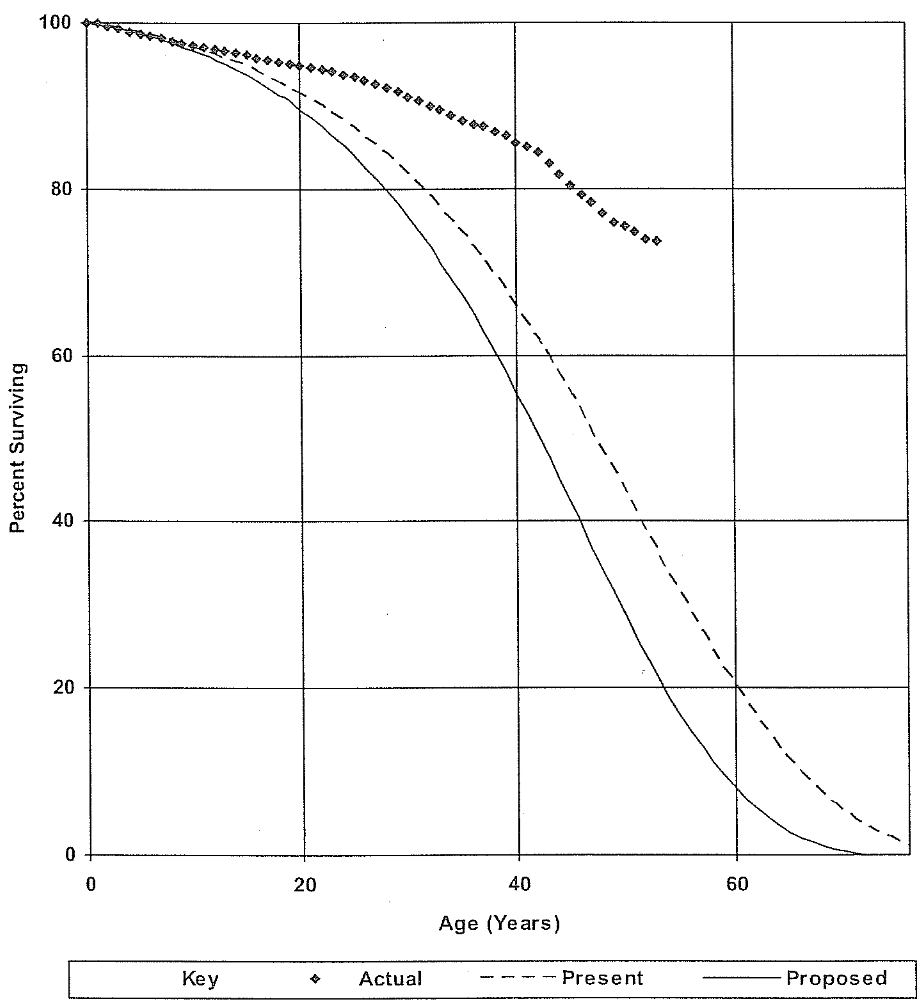
T-Cut: None

Placement Band: 1960-2012

Observation Band: 2000-2012

Current and Proposed Projection Life Curves

Present: 45.0-R2 Proposed: 40.0-R2



Expert Rule 13A

SECTION V

Expert Rule 13A

Title of Report

2013 Depreciation Rate Review
—Distribution Operations
—Common Operations

Consultant

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 260
Fort Myers, FL 33908

Qualifications

See attached Professional Qualifications.

Instructions Provided

Foster Associates was instructed to conduct a 2013 Depreciation Rate Review and provide recommended depreciation rates for USoA categories derived from service life statistics estimated for category classifications adopted by Hydro One Networks for engineering operations and planning purposes.

Basis of Evidence

Specific information and factual assumptions upon which the 2013 Depreciation Rate Review is based are contained within the titled report.

Confirmation

Dr. White has been made aware of and agrees to accept the responsibilities that are or may be imposed as set forth in Rule 13A.

Ronald E. White, Ph.D.
January 22, 2014

PROFESSIONAL QUALIFICATIONS

NAME AND ADDRESS

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 212
Fort Myers, FL 33908

EDUCATION

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

EMPLOYMENT

2007 - Present	Foster Associates, Inc. Chairman
1996 - 2007	Foster Associates, Inc. Executive Vice President
1988 - 1996	Foster Associates, Inc. Senior Vice President
1979 - 1988	Foster Associates, Inc. Vice President
1978 - 1979	Northern States Power Company Assistant Treasurer
1974 - 1978	Northern States Power Company Manager, Corporate Economics

1972 - 1974	Northern States Power Company Corporate Economist
1970 - 1972	Iowa State University Graduate Student and Instructor
1968 - 1970	Northern States Power Company Valuation Engineer
1965 - 1968	Iowa State University Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

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Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Ga Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Kansas Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. D.P.U. 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

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New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

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Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

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Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

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Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

SPEAKER

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety–Fifth Annual Arizona Tax Conference, August 2012.

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Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

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Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

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Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

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Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.Page 60

MODERATOR

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

HONORS AND AWARDS

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

Under the *Electricity Act, 1998*, Hydro One Networks Inc. ("Networks") is required to make payments in lieu of corporate income taxes ("PILS") relating to taxable income earned by its distribution business. The Ontario Energy Board ("the Board") has directed that the taxes payable method should also be used for regulatory purposes (2006 EDR Handbook section 7.1 "OEB 2006 regulatory expense methodology").

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILS income tax payable being different than the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from the customers at that time.

PILS installments are remitted by Networks to OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by February 28th of the following year.

The 2015 to 2019 Hydro One Distribution regulatory tax calculation has been prepared in accordance with the 2006 EDR Handbook and the 2006 EDR Tax Model.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO):

A combined rate of 26.5% (Federal 15% and Ontario 11.5%) has been used for 2015 through 2019. Prior to 2015, the following combined income tax rate was in effect: 31% in 2010, 28.25% in 2011 and 26.5% for 2012 through 2014.

Any variance between actual taxes payable and forecast taxes, as a result of rate changes for income tax or capital cost allowance will be captured in a deferral account for tax rate changes, described further in Exhibit F1, Tab 1, Schedules 1 and 2.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliations between the regulatory net income before tax ("NIBT") and taxable income for the test years 2015 through 2019 are provided in Exhibit C2, Tab 5, Schedule 1, Attachment A. This schedule contains the income tax component of the PILS computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation, capital cost allowance ("CCA") etc.

Reconciliations between the accounting NIBT and taxable income for the historical years 2010, 2011, 2012 and 2013 are provided in Exhibit C2, Tab 5, Schedule 1, Attachment C.

In order to make it easier to follow these reconciliations, the adjustments have been grouped into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement or for which appropriate tax adjustments are made (e.g. depreciation vs. CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and
5) Items where the impact is immaterial in total, and as such, have not been included in our business plan (applicable to test year only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Hydro One Distribution's taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as other post employment benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, transmission export revenue). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, the NIBT must be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

5.0 TREAMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities (i.e. on their balance sheet) for foregone revenue or for expenses that have been incurred for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board often through a rate rider process.

For example, as shown in Table 1, assuming that a 25% tax rate and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a 2-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 1

	Year 1	**Year 2**	**Year 3**	**CUM**
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	25	(12.5)	(12.5)	Nil
Cash Inflow (outflow)	(75)	37.5	37.5	Nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the *"2006 EDR Handbook Report of the Board"* issued May 11, 2005 (Page 61) that stated as follows:

> "A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (e.g. obsolescence provisions, lawsuits, staff reductions, etc.), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward with NIBT either decreasing or increasing respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

It is not necessary to adjust the 2015 through 2019 NIBT for contingent liabilities in computing taxable income since no changes were forecasted in the contingent liability balances for the test years. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

The combined (Federal and Ontario) enacted income tax rates are as follows:

	Historic				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Federal Tax Rate (%)	18.00	16.50	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	13.00	11.75	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**31.00**	**28.25**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Service
Historical (2010, 2011 2012, 2013), Bridge (2014) and Test (2015 to 2019) Years
Year Ending December 31
($ Millions)

Line No.	Particulars	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Reference
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Total Operation, Maintenance & Administrative Expenses	550.9	554.5	553.4	597.5	581.3	564.3	610.2	614.0	603.9	600.0	Exhibit C1, Tab 2, Schedule 1
2	Depreciation & Amortization Expenses*	269.8	286.9	308.1	324.0	302.9	353.6	373.2	390.5	404.6	416.6	Exhibit C1, Tab 6, Schedule 1
3	Income Taxes**	8.0	66.1	43.6	18.9	16.8	55.6	61.6	62.2	65.6	69.4	Exhibit C2, Tab 5, Schedule 1 for test years only
4	**Total Cost of Service**	**828.7**	**907.5**	**905.1**	**940.4**	**901.0**	**973.5**	**1045.0**	**1066.7**	**1074.1**	**1086.0**	

* The depreciation and amortization amount in 2010 does not include the $7.7 million in other regulatory amortization, more details are provided at Exhibit C1, Tab 6, Schedule 1.
** The numbers shown for historical years reflect the actual amounts in Hydro One Distribution's audited financial statements, thus including both current and deferred provision for PILs.

COMPARISON OF OM&A EXPENSE BY MAJOR CATEGORY

Distribution OM&A ($millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sustaining OM&A										
Stations	27.2	25.8	26.4	22.3	27.9	27.6	28.4	28.9	28.6	28.3
Lines	124.4	137.4	130.9	148.1	134.0	141.3	149.7	152.4	154.6	157.5
Meters, Telecom & Control	24.1	26.6	14.2	14.2	19.4	18.5	18.7	18.5	18.9	19.4
Vegetation Management	130.2	127.3	136.4	133.5	139.1	142.0	177.6	180.3	161.1	152.9
Total Sustaining OM&A	**305.9**	**317.1**	**307.9**	**318.1**	**320.4**	**329.5**	**374.4**	**380.1**	**363.2**	**358.1**
Development OM&A										
Data Collection, Engineering and Technical Studies	6.6	4.2	3.9	4.7	4.7	4.7	4.7	4.7	4.9	5.0
Distribution Generation Connections	0.0	2.8	2.9	1.3	2.0	2.2	2.0	2.0	2.0	2.1
Standards and Technology	5.4	6.1	4.2	4.4	5.6	5.6	5.8	6.0	6.1	6.3
Smart Grid Studies	0.3	2.7	3.7	1.7	6.1	2.9	5.2	4.3	4.3	4.4
Total Development OM&A	**12.3**	**15.8**	**14.7**	**12.1**	**18.4**	**15.4**	**17.7**	**17.0**	**17.4**	**17.8**
Operations OM&A										
Operations Support	4.4	4.2	4.8	5.4	5.2	5.3	5.4	5.5	5.5	5.6
Operations	12.3	13.0	14.8	15.0	16.7	16.9	17.1	17.1	17.4	17.6
Health, Safety & Environment	1.8	0.9	1.4	2.3	2.4	2.7	2.8	2.6	2.6	2.7
Smart Grid	0.0	0.0	0.0	0.0	6.1	5.3	9.1	9.6	16.8	15.1
Total Operations OM&A	**18.5**	**18.1**	**21.0**	**22.7**	**30.4**	**30.2**	**34.4**	**34.8**	**42.2**	**41.0**

Distribution OM&A ($millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer Service OM&A										
Customer Operations	105.5	101.3	105.2	118.7	109.2	96.8	96.2	96.6	98.0	99.6
Distributed Generation	5.0	9.5	9.0	7.3	7.7	7.9	8.1	8.3	8.5	8.7
Conservation & Demand Management	1.7	2.0	1.6	2.4	3.1	3.1	2.7	2.7	2.8	2.8
Customer Experience	0.0	0.0	0.0	1.9	4.2	4.3	4.3	4.3	4.2	4.3
Smart Grid Pilot	2.5	0.4	0.8	7.0	9.5	5.7	4.9	2.8	0.0	0.0
Total Customer Service OM&A	**114.7**	**113.3**	**116.7**	**137.3**	**133.7**	**117.8**	**116.3**	**114.7**	**113.5**	**115.4**
OM&A Common Corporate Costs and Other Costs										
Asset Management	30.6	34.6	25.1	20.9	18.4	18.4	17.8	17.6	17.5	17.8
Common Corporate Functions & Services	69.7	68.5	71.5	79.2	79.1	77.2	76.8	76.7	78.6	79.9
Information Technology (including Cornerstone)	71.2	72.6	80.6	103.1	86.0	85.7	86.4	86.1	86.5	87.6
Cost of Sales	5.4	5.8	18.5	2.1	2.0	2.1	2.1	2.1	2.2	2.2
Other	-82.0	-96.0	-107.1	-102.6	-111.7	-116.7	-120.6	-120.1	-122.4	-125.2
Total OM&A Common Corporate Costs and Other Costs	**94.9**	**85.5**	**88.6**	**102.8**	**73.8**	**66.7**	**62.5**	**62.4**	**62.4**	**62.3**
Property Taxes & Rights Payments	**4.6**	**4.6**	**4.5**	**4.5**	**4.6**	**4.7**	**4.9**	**5.0**	**5.2**	**5.4**
Total Distribution OM&A	**550.9**	**554.4**	**553.4**	**597.5**	**581.3**	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

COMPARISON OF WAGES AND SALARIES

1.0 REGIONAL MAINTAINER LINES – (PWU-REPRESENTED)

The following summarizes the key elements of this job classification and related compensation:

- works on transmission and distribution lines and associated apparatus using a range of mechanical and electrical skills and knowledge; and
- Grade 12 plus six-year apprenticeship.

Table 1
Average Annual Salary — Regional Maintainer Lines

Year	Total Wages	Base	Overtime	Incentive	Other*
2010	$125,425	$83,418	$38,987	$0	$3,020
2011	$121,871	$82,122	$35,028	$0	$4,720
2012	$122,844	$84,280	$33,428	$0	$5,136
2013	$125,915	$86,387	$34,264	$0	$5,264
2014	$129,063	$88,546	$35,121	$0	$5,396
2015	$131,644	$90,317	$35,823	$0	$5,504
2016	$134,277	$92,124	$36,540	$0	$5,614
2017	$136,963	$93,966	$37,270	$0	$5,726
2018	$139,702	$95,846	$38,016	$0	$5,840
2019	$142,496	$97,762	$38,776	$0	$5,957

*Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

2.0 SOCIETY REPRESENTED MP4 (Example: ENGINEER – JOURNEY PERSON LEVEL)

The following summarizes the key elements of this job classification and related compensation:

- Professional Engineer with 8-10 years' experience;
- participates in the design and development of strategies and proposes effective recommendations related to the application and design and performance of various systems, e.g., electrical power systems/telecommunication; and
- provides technical guidance and supervision to technical staff.

Table 2
Average Annual Salary (MP4)

Year	Total Wages	Base	Overtime	Incentive	Other*
2010	$107,514	$104,182	$1,359	$0	$1,973
2011	$105,311	$99,401	$3,581	$0	$2,329
2012	$106,774	$101,084	$3,101	$0	$2,590
2013	$108,910	$103,105	$3,163	$0	$2,642
2014	$111,088	$105,167	$3,226	$0	$2,695
2015	$113,588	$107,534	$3,299	$0	$2,755
2016	$115,859	$109,684	$3,365	$0	$2,810
2017	$118,177	$111,878	$3,432	$0	$2,866
2018	$120,540	$114,115	$3,501	$0	$2,924
2019	$122,951	$116,398	$3,571	$0	$2,982

*Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

3.0 MANAGER – BAND 7 (MANAGEMENT COMPENSATION PLAN)

The following summarizes the key elements of this job classification and related compensation:

- university degree with several years' experience;
- provides direction with respect to corporate strategies and policies, budget and programs, compliance and performance targets and expectations of continuous improvement;
- manages the coordination of work activities of supervisory professional staff; and
- co-ordinates the activities of others in the performance of technical projects related to program processes, technical/operational business standards and procedures.

Table 3
Average Annual Salary – MCP Band 7

Year	Total Wages	Base	Overtime	Incentive	Other*
2010	$128,129	$107,416	$0	$12,460	$8,253
2011	$123,461	$107,565	$0	$8,683	$7,210
2012	$124,347	$108,235	$0	$9,365	$6,747
2013	$126,834	$110,400	$0	$9,552	$6,881
2014	$129,371	$112,608	$0	$9,744	$7,019
2015	$131,958	$114,860	$0	$9,938	$7,160
2016	$134,597	$117,157	$0	$10,137	$7,303
2017	$137,289	$119,501	$0	$10,340	$7,449
2018	$140,035	$121,891	$0	$10,547	$7,598
2019	$142,836	$124,328	$0	$10,758	$7,750

*Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Depreciation & Amortization Expenses
Bridge Year (2014) and Test Years (2015 to 2019)
Year Ending December 31
($ Millions)

Line No.	Particulars	2014 Deprn Rate	2014 Provision ($M)	2015 Deprn Rate	2015 Provision ($M)	2016 Deprn Rate	2016 Provision ($M)	2017 Deprn Rate	2017 Provision ($M)	2018 Deprn Rate	2018 Provision ($M)	2019 Deprn Rate	2019 Provision ($M)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Depreciation Expenses												
1	Major Fixed Assets	2.79%	211.4	2.70%	253.7	2.66%	262.2	2.65%	275.6	2.60%	286.3	2.55%	294.7
2	Minor Fixed Assets	9.60%	42.2	9.28%	44.5	8.88%	45.7	8.39%	46.2	7.99%	47.4	7.73%	49.3
3	Depreciation on Fixed Assets		253.6		298.2		308.0		321.8		333.7		343.9
4	Less Capitalized Depreciation		(12.7)		(13.2)		(13.7)		(14.0)		(14.4)		(14.8)
5	Asset Removal Costs		50.7		54.5		57.0		60.4		63.3		65.8
6	Total Depreciation Expenses		291.7		339.5		351.3		368.1		382.6		395.0
	Amortization Expenses												
7	Environmental Costs		11.2		14.2		22.0		22.4		22.0		21.6
8	Other Regulatory Amortization		0.0		0.0		0.0		0.0		0.0		0.0
9	Other Amortization		0.0		0.0		0.0		0.0		0.0		0.0
10	Total Amortization Expenses		11.2		14.2		22.0		22.4		22.0		21.6
11	Total Depreciation & Amortization Expenses		302.9		353.6		373.2		390.5		404.6		416.6
12	Exclude Other Reg Amort		0.0		0.0		0.0		0.0		0.0		0.0
13	Depreciation & Amortization for recovery		302.9		353.6		373.2		390.5		404.6		416.6

CALCULATION OF UTILITY INCOME TAXES (INCLUDING TAX CREDIT EXEMPTIONS)

- Attachment 1: Calculation of Utility Income Taxes Test Years (2015, 2016, 2017, 2018, 2019)
- Attachment 2: Calculation of Capital Cost Allowance Test Years (2015, 2016, 2017, 2018, 2019)
- Attachment 3: Calculation of Utility Income Taxes Historical Years (2010, 2011, 2012)
- Attachment 4: Calculation of Capital Cost Allowance Historical Years (2010, 2011, 2012)
- Attachment 5: Calculation of Capital Cost Allowance Bridge Years (2013, 2014)
- Attachment 6: Calculation of Apprenticeship and Education Tax Credit Test Years (2015, 2016, 2017, 2018, 2019)
- Attachment 7: Calculation of Apprenticeship and Education Tax Credit Historical Years (2010, 2011, 2012)

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Test Years (2015 to 2019)
Year Ending December 31
($ Millions)

Line No.	Particulars	2015 (a)	2016 (b)	2017 (c)	2018 (d)	2019 (e)
	Determination of Taxable Income					
1	Regulatory Net Income (before tax)	$ 307.2	$ 330.9	$ 350.7	$ 372.4	$ 392.7
2	Book to Tax Adjustments:					
3	Other Post Employment Benefits expense	27.9	26.4	22.9	23.9	22.7
4	Other Post Employment Benefits payments	(31.1)	(33.7)	(35.6)	(37.4)	(39.7)
5	Inergi pension payments	0.0	0.0	0.0	0.0	0.0
6	Depreciation and amortization	353.6	373.2	390.5	404.6	416.6
7	Capital Cost Allowance	(364.1)	(375.3)	(404.9)	(426.1)	(439.2)
8	Removal costs deductible for tax	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)
9	Environmental costs	(14.2)	(22.0)	(22.4)	(22.0)	(21.6)
10	Hedge loss - amortization	0.1	0.1	0.1	0.1	0.1
11	Non-deductible meals & entertainment	2.4	2.4	2.4	2.4	2.4
12	Capital amounts expensed for accounting	6.7	6.7	6.7	6.7	6.7
13	Research & Development Tax Credit	1.2	1.2	1.2	1.2	1.2
14	Federal Apprenticeship Tax Credits	0.3	0.3	0.3	0.3	0.3
15	Capitalized overhead costs deductible for tax	(21.8)	(20.7)	(20.4)	(20.9)	(21.7)
16	Capitalized pension costs deductible for tax	(45.2)	(43.5)	(43.5)	(44.9)	(45.9)
17	Debt Issuance costs - amortization	1.1	1.2	1.3	1.4	1.4
18	Debt Issuance costs - 21(e) deduction	(1.7)	(2.0)	(2.0)	(2.1)	(2.1)
19	Premium/Discount - amortization	(0.6)	(0.7)	(0.7)	(0.4)	(0.5)
20	Bond discount deduction	(0.4)	(0.2)	0.0	0.0	0.0
		$ (91.8)	$ (92.7)	$ (110.1)	$ (119.2)	(125.2)
21	Regulatory Taxable Income	$ 215.4	$ 238.1	$ 240.6	$ 253.1	$ 267.5
22	Corporate Income Tax Rate	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %
23	Subtotal	$ 57.1	$ 63.1	$ 63.8	$ 67.1	$ 70.9
24	Less: R&D ITC / Federal Apprenticeship ITC	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
25	Regulatory Income Tax	$ 55.6	$ 61.6	$ 62.2	$ 65.6	$ 69.4
	Tax Rates					
26	Federal Tax	15.00 %	15.00 %	15.00 %	15.00 %	15.00 %
27	Provincial Tax	11.50 %	11.50 %	11.50 %	11.50 %	11.50 %
28	Total Tax Rate	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
2015 to 2019 Networks Allocation to Dx
Year Ending December 31
($ Millions)

2015 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,575.4	20.0	1,595.4	9.98	1,585.4	4%	63.4	1,532.0
2	257.1	0.0	257.1	-	257.1	6%	15.4	241.7
3	11.2	0.0	11.2	-	11.2	5%	0.6	10.6
6	9.6	0.0	9.6	-	9.6	10%	1.0	8.6
8	116.2	30.2	146.4	15.11	131.3	20%	26.3	120.1
9	0.9	0.0	0.9	-	0.9	25%	0.2	0.7
10	96.9	31.3	128.2	15.66	112.5	30%	33.8	94.4
12	12.0	11.2	23.2	5.62	17.6	100%	17.6	5.6
13	10.8	3.6	14.4	1.81	12.6	SL	1.6	12.8
17	6.5	0.0	6.5	-	6.5	8%	0.5	6.0
42	0.1	0.0	0.1	-	0.1	12%	-	0.1
45	0.1	0.0	0.1	-	0.1	45%	0.1	0.0
46	0.7	0.0	0.7	-	0.7	30%	0.2	0.5
47	2,259.7	374.5	2,634.2	187.27	2,446.9	8%	195.8	2,438.4
50	16.3	6.2	22.5	3.09	19.4	55%	10.7	11.8
Dx CCA	4,373.4	477.1	4,850.5	238.5	4,612.0		367.2	4,483.3
DX CEC Continuity	31.5	3.7	35.2	0.0	35.2	7%	2.3	32.9
					Non-Regulatory		(4.2)	
					Adjustment to CCA re goodwill		(1.2)	
					Total CCA for RR		364.1	

2016 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,532.0	19.8	1,551.7	9.9	1,541.8	4%	61.7	1,490.0
2	241.7	(0.0)	241.7	-	241.7	6%	14.5	227.2
3	10.6	0.0	10.6	-	10.6	5%	0.5	10.1
6	8.6	0.0	8.7	-	8.7	10%	0.9	7.8
8	120.1	52.9	173.1	26.4	146.6	20%	29.3	143.7
9	0.7	(0.0)	0.7		0.7	25%	0.2	0.5
10	94.4	36.7	131.1	18.3	112.8	30%	33.8	97.2
12	5.6	17.2	22.8	8.6	14.2	100%	14.2	8.6
13	12.8	2.8	15.6	1.4	14.2	SL	1.9	13.7
17	6.0	(0.0)	6.0		6.0	8%	0.5	5.5
42	0.1	(0.0)	0.1	-	0.1	12%	0.0	0.1
45	0.0	0.0	0.1	-	0.1	45%	0.0	0.0
46	0.5	(0.0)	0.5	-	0.5	30%	0.1	0.3
47	2,438.4	417.6	2,856.0	208.8	2,647.2	8%	211.8	2,644.2
50	11.8	11.8	23.6	5.9	17.7	55%	9.8	13.8
Dx CCA	4,483.3	558.9	5,042.2	279.3	4,762.8		379.3	4,662.9
DX CEC Continuity	32.9	3.8	36.9		36.9	7%	2.5	34.4
					Non-Regulatory		(5.3)	
					Adjustment to CCA re goodwill		(1.1)	
					Total CCA for RR		375.3	

2017 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,490.0	19.4	1,509.4	9.7	1,499.7	4%	60.0	1,449.4
2	227.2	0.0	227.2	-	227.2	6%	13.6	213.5
3	10.1	0.0	10.1	-	10.1	5%	0.5	9.6
6	7.8	0.0	7.8	-	7.8	10%	0.8	7.0
8	143.7	48.9	192.6	24.4	168.2	20%	33.6	159.1
9	0.5	0.0	0.5	-	0.5	25%	0.1	0.4
10	97.2	34.0	131.2	17.0	114.2	30%	34.3	96.9
12	8.6	23.5	32.1	11.8	20.4	100%	20.4	11.8
13	13.7	2.8	16.5	1.4	15.1	SL	2.1	14.3
17	5.5	0.0	5.5	-	5.5	8%	0.4	5.1
42	0.1	0.0	0.1	-	0.1	12%	0.0	0.1
45	0.0	(0.0)	-	(0.0)	0.0	45%	0.0	(0.0)
46	0.3	0.0	0.3	-	0.3	30%	0.1	0.2
47	2,644.2	496.9	3,141.2	248.5	2,892.7	8%	231.4	2,909.7
50	13.8	19.6	33.4	9.8	23.6	55%	13.1	20.3
Dx CCA	4,662.9	645.0	5,307.9	322.5	4,985.4		410.5	4,897.4
				-				
DX CEC Continuity	34.4	4.0	38.5		38.5	7%	2.6	35.9
					Non-Regulatory		(7.2)	
					Adjustment to CCA re goodwill		(1.1)	
					Total CCA for RR		404.9	

2018

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,449.4	18.0	1,467.4	9.0	1,458.4	4%	58.3	1,409.1
2	213.5	-	213.5	-	213.5	6%	12.8	200.7
3	9.6	-	9.6	-	9.6	5%	0.5	9.1
6	7.0	-	7.0	-	7.0	10%	0.7	6.3
8	159.1	25.2	184.2	12.6	171.6	20%	34.3	149.9
9	0.4	-	0.4	-	0.4	25%	0.1	0.3
10	96.9	38.3	135.2	19.1	116.1	30%	34.8	100.4
12	11.8	10.8	22.6	5.4	17.2	100%	17.2	5.4
13	14.3	3.2	17.5	1.6	15.9	SL	2.4	15.1
17	5.1	-	5.1	-	5.1	8%	0.4	4.6
42	0.1	0.0	0.1	-	0.1	12%	0.0	0.1
45	(0.0)	0.0	0.0	-	-	45%	-	0.0
46	0.2	(0.0)	0.2	-	0.2	30%	0.1	0.1
47	2,909.7	645.1	3,554.8	322.6	3,232.2	8%	258.6	3,296.2
50	20.3	5.6	25.9	2.8	23.1	55%	12.8	13.1
Dx CCA	4,897.4	746.1	5,643.5	373.0	5,270.4		433.1	5,210.5
DX CEC Continuity	35.9	4.6	40.5		40.5	7%	2.7	37.8
					Non-Regulatory		(8.7)	
					Adjustment to CCA re goodwill		(1.0)	
					Total CCA for RR		426.1	

2019

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,409.1	16.3	1,425.4	8.2	1,417.2	4%	56.7	1,368.7
2	200.7	0.0	200.7	-	200.7	6%	12.0	188.7
3	9.1	0.0	9.1	-	9.1	5%	0.5	8.6
6	6.3	0.0	6.3	-	6.3	10%	0.6	5.7
8	149.9	20.3	170.2	10.2	160.1	20%	32.0	-
9	0.3	0.0	0.3	-	0.3	25%	0.1	138.2
10	100.4	35.2	135.6	17.6	118.0	30%	35.4	0.2
12	5.4	12.8	18.2	6.4	11.8	100%	11.8	100.2
13	15.1	3.2	18.3	1.6	16.7	SL	2.6	6.4
17	4.6	0.0	4.6	-	4.6	8%	0.4	15.7
42	0.1	(0.0)	0.1	-	0.1	12%	0.0	4.3
45	0.0	(0.0)	0.0	-	0.0	45%	0.0	0.1
46	0.1	0.0	0.2	-	0.1	30%	0.0	0.0
47	3,296.2	505.8	3,802.0	252.9	3,549.1	8%	283.9	0.1
50	13.1	7.8	20.9	3.9	17.0	55%	9.3	3,518.1
Dx CCA	5,210.5	601.5	5,811.9	300.7	5,511.1		445.4	5,355.0
DX CEC Continuity	37.8	4.5	42.4		42.4	7%	3.0	39.5
					Non-Regulatory		(8.2)	
					Adjustment to CCA re goodwill		(0.9)	
					Total CCA for RR		439.2	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Historic Years
Calculation of Utility Income Taxes Historical Years (2010, 2011, 2012)
Year Ending December 31
($ Millions)

Line No.	Particulars		2010		2011		2012	
	Calculation of Federal and ON Taxable Income							
1	Net Income Before Tax (NIBT)	$	201.9	$	302.3		301.9	
2	**Required Adjustments to accounting NIBT**							
3	**Recurring items included in Revenue Requirement (RR):**							
4	Other Post Employment Benefit expense greater than payments		5.1		10.4		1.0	
5	Depreciation and amortization		277.5		286.9		308.1	
6	Capital Cost Allowance		(329.7)		(302.5)		(330.6)	
7	Cumulative Eligible Capital						(0.3)	
8	Removal costs		(5.3)		(5.5)		(6.8)	
9	Environmental costs paid		(9.4)		(7.7)		(9.2)	
10	Non-deductible items (50% Meals & entertainment / interest)		3.0		2.8		2.2	
11	R & D Fed ITC/ Apprenticeship (prior yr addback)		0.9		0.6		3.4	
12	Capitalized overhead costs deducted		(18.0)		(17.7)		(23.0)	
13	Capital additions deducted for accounting		2.6		9.0		8.6	
14	Capitalized Pension cost deductions		(35.2)		(36.5)		(43.8)	
15		$	(108.5)	$	(60.2)	$	(90.4)	
16	Deferral accounts not part of RR:							
17	RSVA/RRRP		(24.9)		32.7		3.2	
18	Restricted Depreciation		0.0		0		0.0	
19	Smart meter costs deferred		15.9		6.7		(1.2)	
20	Tx Export credit/Deferred export Rev		0.0		0		0.0	
21	Deferred Pension		(11.6)		-13.1		(16.3)	
22	Deferral a/c's etc.		(3.9)		7.8		(0.5)	
23	Tax Changes deferral a/c s		0		4.4		7.1	
24	Riders 3/6/8		28.5		1.5		2.8	
25		$	4.0		40.0		(4.9)	
26	Reversal of accounting adjustments not part of RR:							
27	Contingent liability movement		(4.0)		(2.0)		1.6	
28	Capitalized interest deductible for tax		(9.0)		(10.6)		(18.4)	
29	Capitalized SRED deducted for ta		0.0		0.0		(19.2)	
30		$	(13.0)	$	(12.6)	$	(36.0)	
31	Recurring items not part of RR:							
32	Cumulative Eligible Capital	$	(2.4)	$	(2.2)		(1.8)	
33								
34	Immaterial items not in business plan detail:							
35								
36	Reverse Insurance proceeds included in NIBT		0.0		0.0		0.0	
37	Net Underwriting/Finance costs		(1.5)		(1.4)		(1.6)	
38	WSIB		(1.0)		(1.0)		0.0	
39	Tenant Inducement		(1.0)		1.0		(1.0)	
40	Capital tax paid vs. accrued		(0.7)		0.3		0.0	
41	Other		0.2		(0.4)		0.9	
42		$	(4.0)	$	(1.5)		(1.7)	
43								
44	NET Adjustments to Accounting NIBT	$	(123.9)	$	(36.5)		(134.8)	
45								
46	Taxable Income	$	78.0	$	265.8		167.1	
47								

NOTE:
Transmission includes Five Nations data

Line No.								
51	Taxable Income	$	78.0	$	265.8	$	167.1	
52								
53	Corporate Income Tax Rate		31.00	%	28.25	%	26.50	%
54								
55	Subtotal	$	24.2	$	75.1	$	44.3	
56	Less: Tax credits		(3.3)		(6.6)		(8.5)	
57	Income Tax	$	20.9	$	68.5	$	35.7	
58								
59								
60								
61	Tax Rates							
62								
63	Federal Tax		18.00	%	17.00	%	15.00	%
64	Provincial Tax		13.00	%	11.25	%	11.50	%
65	Total Tax Rate		31.00	%	28.25	%	26.50	%

See Exhibit C1, Tab 7, Schedule 1 for additional information

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Historic Years
Calculation of Capital Cost Allowance Historical Years (2010, 2011, 2012)
Year Ending December 31
($ Millions)

2010

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,877.8	10.0	1,887.8	5.0	1,882.8	4%	75.3	1,812.5
2	350.2	0.1	350.3	0.0	350.2	6%	21.0	329.3
3	13.8	0.0	13.8	0.0	13.8	5%	0.7	13.1
6	8.4	4.3	12.7	2.1	10.5	10%	1.1	11.6
8	45.9	29.1	75.0	14.5	60.4	20%	12.1	62.9
9	4.0	0.0	4.0	0.0	4.0	25%	1.0	3.0
10	75.5	50.5	126.0	25.2	100.7	30%	30.1	95.9
12	35.7	57.8	93.5	28.9	64.6	100%	64.6	10.3
13	1.3	-	1.3	-	1.3	SL	0.3	1.0
17	2.6	0.7	3.3	0.3	2.9	8%	0.2	3.1
42	0.2	0.0	0.2	0.0	0.2	12%	0.0	0.2
45	2.4	-	2.4	-	2.4	45%	1.1	1.3
46	0.3	-	0.3	-	0.3	30%	0.1	0.2
47	1,183.8	346.0	1,529.8	173.0	1,356.8	8%	107.1	1,422.7
50	4.5	-	4.5	-	4.5	55%	2.5	2.0
52	-	12.6	12.6	12.6	12.6	100%	12.6	-
Dx CCA	3,606.4	511.1	4,117.5	261.9	3,868.3		329.7	3,769.3
Dx CEC Continuity	34.2		34.2		34.2	7%	2.4	31.8
				Plus: Adjustment to CCA re goodwill			(2.1)	
				Total CCA for RR			330.0	

2011

CCA Class	Opening UCC	Additions	UCC pre-1/2 yr	0% net additior	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,812.5	11.9	1,824.4	7.3	1,817.1	4%	72.7	1,751.7
2	329.3	-	329.3	0.0	329.3	6%	19.8	309.5
3	13.1	0.6	13.7	0.0	13.7	5%	0.7	13.0
6	11.6	1.2	12.8	0.6	12.2	10%	1.2	11.6
8	62.9	20.5	83.4	10.3	73.1	20%	14.6	68.8
9	3.0	-0.1	2.9	-	2.9	25%	0.7	2.2
10	95.9	32.5	128.4	16.6	111.8	30%	33.5	94.9
12	10.3	20.0	30.3	11.8	18.5	100%	18.5	11.8
13	1.0	3.3	4.3	1.7	2.6	SL	0.6	3.7
17	3.1	3.6	6.7	1.8	4.9	8%	0.4	6.3
42	0.2	-	0.2	0.0	0.2	12%	-	0.2
45	1.3	-	1.3	-	1.3	45%	0.6	0.7
46	0.2	-	0.2	-	0.2	30%	0.1	0.1
47	1,422.7	327.0	1,749.8	167.9	1,581.9	8%	126.6	1,623.2
50	2.0	40.7	42.7	20.4	22.3	55%	12.3	30.4
52	-	0.2	0.2	-	0.2	100%	0.2	-
Dx CCA	3,769.3	461.3	4,230.6	238.5	3,992.2		302.5	3,928.1
Dx CEC Continuity	31.8		31.8		31.8	7%	2.2	29.6
				Plus: Adjustment to CCA re goodwill			(2.0)	
				Total CCA for RR			302.8	

2012

CCA Class	Opening UCC	Additions	UCC pre-1/2 yr	0% net additior	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,751.7	1.7	1,753.4	0.8	1,752.5	4%	70.1	1,683.3
2	309.5	-	309.5	-	309.5	6%	18.6	290.9
3	13.0	-	13.0	-	13.0	5%	0.7	12.3
6	11.6	1.5	13.1	0.8	12.4	10%	1.2	11.9
8	68.8	66.8	135.6	39.7	95.9	20%	19.2	116.4
9	2.2	-	2.2	-	2.2	25%	0.5	1.6
10	94.9	37.2	132.1	18.6	113.5	30%	34.0	98.1
12	11.8	19.7	31.5	9.9	21.6	100%	21.6	9.9
13	3.7	0.4	4.1	0.2	3.9	SL	0.6	3.4
17	6.3	2.1	8.4	1.0	7.3	8%	0.6	7.7
42	0.2	-	0.2	-	0.2	12%	0.0	0.1
45	0.7	-	0.7	-	0.7	45%	0.3	0.4
46	0.1	1.5	1.6	0.7	0.9	30%	0.3	1.4
47	1,623.2	315.5	1,938.7	157.5	1,781.2	8%	142.5	1,796.2
50	30.4	19.9	50.3	13.3	37.0	55%	20.4	30.0
Dx CCA	3,928.1	466.3	4,394.4	242.5	4,151.7		330.6	4,063.6
Dx CEC Continuity	29.6	0.4	30.0		30.0	7%	2.1	27.9
				Plus: Adjustment to CCA re goodwill			(1.8)	
				Total CCA for RR			330.9	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
2013 and 2014 Networks Allocation to Distribution
Year Ending December 31
($ Millions)

2013

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,683.3	(8.1)	1,675.2	-	1,675.22	4%	67.0	1,608.2
2	290.9	0.0	290.9	-	290.95	6%	17.5	273.4
3	12.3	0.1	12.4	-	12.39	5%	0.6	11.8
6	11.9	(0.0)	11.9	-	11.90	10%	1.2	10.7
8	116.4	20.4	136.8	10.2	126.58	20%	25.3	111.5
9	1.6	0.1	1.7	-	1.65	25%	0.5	1.2
10	98.1	40.0	138.1	20.0	118.07	30%	35.4	102.7
12	9.9	156.8	166.7	78.4	88.28	100%	88.3	78.4
13	3.4	1.9	5.3	0.9	4.38	SL	0.7	4.6
17	7.7	(0.0)	7.7	-	7.67	8%	0.6	7.1
42	0.1	0.0	0.1	-	0.14	12%	-	0.1
45	0.4	(0.0)	0.4	-	0.40	45%	0.2	0.2
46	1.4	(0.0)	1.4	-	1.37	30%	0.4	1.0
47	1,796.2	402.1	2,198.3	201.1	1,997.26	8%	159.8	2,038.5
50	30.0	16.0	46.0	7.9	38.06	55%	21.0	25.0
Dx CCA	4,063.6	629.3	4,692.9	318.5	4,374.3		418.5	4,274.4
DX CEC Continuity	27.9	2.8	30.8	0.0	30.8	7%	2.1	28.7
					Goodwill		(1.4)	
					Non-Regulatory		(38.2)	
					Total CCA for RR		381.0	

2014

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,608.2	32.2	1,640.4	16.1	1,624.3	4%	65.0	1,575.4
2	273.4	0.1	273.5	0	273.5	6%	16.4	257.1
3	11.8	0.0	11.8	0	11.8	5%	0.6	11.2
6	10.7	0.0	10.7	0	10.7	10%	1.1	9.6
8	111.5	30.0	141.5	15.0	126.5	20%	25.3	116.2
9	1.2	0.0	1.2	0	1.2	25%	0.3	0.9
10	102.7	29.4	132.1	14.7	117.4	30%	35.2	96.9
12	78.4	24.0	102.4	12.0	90.4	100%	90.4	12.0
13	4.6	7.3	11.9	3.7	8.3	SL	1.1	10.8
17	7.1	0.0	7.1	0	7.1	8%	0.6	6.5
42	0.1	0.0	0.1	0	0.1	12%	0.0	0.1
45	0.2	0.0	0.2	0	0.2	45%	0.1	0.1
46	1.0	0.0	1.0	0	1.0	30%	0.3	0.7
47	2,038.5	400.2	2,438.8	200.1	2,238.6	8%	179.1	2,259.7
50	25.0	7.0	31.9	3.5	28.5	55%	15.6	16.3
Dx CCA	4,274.3	530.2	4,804.6	265.1	4,539.5		431.1	4,373.4
DX CEC Continuity	28.7	5.1	33.8	0.0	33.8	7%	2.4	31.5
					Goodwill		(1.3)	
					Non-Regulatory		(36.2)	
					Total CCA for RR		396.0	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Historic Years
Tax Credit Text Years (2015, 2016, 2017, 2018, 2019)
Year Ending December 31
($ Thousands)

Line No	Particulars	2015	2016	2017	2018	2019	
1	ON Coop Education Credit	$ 650	$ 650	$ 650	$ 650	$ 650	
2	Eligible Positions	219	219	219	219	219	
3							
4	ON Apprenticeship Credit	$ 3,090	$ 3,090	$ 3,090	$ 3,090	$ 3,090	
5	Eligible Positions	368	368	368	368	368	
6							
7	Ontario Business Research						
8	Institute Credit	$ 130	$ 130	$ 130	$ 130	$ 130	
9							
10	Federal Apprenticeship Credit	$ 300	$ 300	$ 300	$ 300	$ 300	
11	Eligible positions	159	159	159	159	159	
12							
13	SR&ED	1,200	1,200	1,200	1,200	1,200	
14							
15	**TOTAL TAX CREDIT**	**$ 5,370**	**$ 5,370**	**$ 5,370**	**$ 5,370**	**$ 5,370**	
16							
17							
18	Tax Credit included in tax expense	$ 1,500	$ 1,500	$ 1,500	$ 1,500	$ 1,500	(1)
19	Tax Credit included in OM&A	$ 3,870	$ 3,870	$ 3,870	$ 3,870	$ 3,870	(1)
20	**Total**	**$ 5,370**	**$ 5,370**	**$ 5,370**	**$ 5,370**	**$ 5,370**	

(1) In accordance with US GAAP, refundable tax credits are recorded in OM&A and non refundable tax credits are recorded as a reduction to tax expense. Consequently, the tax credits relating Ontario Co-op, Ontario Apprenticeship, and Ontario Business Research are recorded in OM&A.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Historic Years
Calculation of Apprenticeship and Education Tax Credit Historical Years (2010, 2011, 2012)
Year Ending December 31
($ Thousands)

Line No	Particulars	2010	2011	2012
1	ON Coop Education Credit	$ 556	$ 460	$ 590
2	Eligible Positions	181	154	197
3				
4	ON Apprenticeship Credit	$ 1,636	$ 2,085	$ 2,576
5	Eligible Positions	190	227	323
6				
7	Federal Apprenticeship Credit	$ 211	$ 228	$ 177
8	Eligible positions	107	118	104
9				
10	SR&ED	$ 875	$ 3,777	$ 5,199
11				
12	**TOTAL TAX CREDIT**	**$ 3,278**	**$ 6,550**	**$ 8,542**

2012 HYDRO ONE NETWORKS INCOME TAX RETURN

Attachment 1:	Federal and Ontario Income Tax Return
Attachment 2:	Calculation of Utility Income Taxes (Transmission and Distribution)
Attachment 3:	Calculation of Capital Cost Allowance (Transmission and Distribution)
Attachment 4:	Calculation of Apprenticeship, Education and SR&ED Tax Credits

2012 HYDRO ONE NETWORKS INCOME TAX RETURN

Attachment 1: Federal and Ontario Income Tax Return

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 87086 5821 RC0001

Corporation's name
002 Hydro One Networks 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.)
011 483 Bay Street, 8th Floor
012 South Tower
City: 015 Toronto
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 M5G 2P5

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
032
City: 035
Province,territory, or state: 036
Country (other than Canada): 037
Postal code/Zip code: 038

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 2012-01-01 (YYYY MM DD)
Tax year-end: 061 2012-12-31 (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 who own voting shares?	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	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	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 account 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	X	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	X	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	X	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	X	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 (other than transitional reserves under section 34.2)?	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
Did the corporation have any controlled foreign affiliates?	258		T1134
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

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	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		487,936,028	A
Deduct: Charitable donations from Schedule 2	311	381,250		
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		381,250	381,250	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			487,554,778	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		487,554,778	
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)			487,554,778	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8. Use 3.2 for tax years ending before 2012.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	487,891,364	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.57143 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 4 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	487,554,778	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 ***** 22,367,747 D) / 11,250 = 994,122,089 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*			487,554,778	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***	44,664	G		
Total of amounts B to G	44,664	▶	44,664	H
Amount A **minus** amount H (if negative, enter "0")			487,510,114	I

Amount I	487,510,114	x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	J
Amount I	487,510,114	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	K
Amount I	487,510,114	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	= 63,376,315	L

General tax reduction for Canadian-controlled private corporations – Total of amounts J to L ..... 63,376,315 M
Enter amount M 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)				N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O		
Amount QQ from Part 13 of Schedule 27		P		
Personal service business income* 434		Q		
Amount used to calculate the credit union deduction from Schedule 17		R		
Total of amounts O to R		▶		S
Amount N **minus** amount S (if negative, enter "0")				T

Amount T		x	Number of days in the tax year before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	/ 366	x 11.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	366 / 366	x 13 %	=	W

General tax reduction – Total of amounts U to W X
Enter amount X 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	44,664	x 26 2/3 % =	11,910	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")				11,910	C

Taxable income from line 360 on page 3		487,554,778		
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* 100 / 35 =			
Foreign business income tax credit from line 636 on page 7	x 1(0.38 - X**) / 4 =			
		487,554,778		
		x 26 2/3 % =	130,014,607	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			67,267,328	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least		450	11,910	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 based on the number of days in the tax year that are in each calendar year. See page 5.

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		11,910		
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			
		11,910	11,910	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	485		11,910	

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	270,455,293	x 1 / 3	90,151,764	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			11,910	J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)			11,910	

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	185,270,816	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		44,664	i
Taxable income from line 360 on page 3	487,554,778		
Deduct: Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	487,554,778 ▶	487,554,778	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604	2,978	C
Subtotal (**add** amounts A to C)		185,273,794	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	48,755,478			
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 M on page 5	638	63,376,315			
General tax reduction from amount X 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	5,874,673			
Subtotal		118,006,466	▶	118,006,466	E

Part I tax payable – Amount D **minus** amount E	67,267,328	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	67,267,328
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		67,267,328

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	48,620,350	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 2012.)		48,620,350 ▶	48,620,350
Total tax payable	770		115,887,678 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	11,910
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	126,095,684
Total credits	890	126,107,594 ▶ 126,107,594 B

Refund code 894 2 Overpayment 10,219,916

Balance (amount A **minus** amount B) -10,219,916

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 ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 BARAGETTI (Last name (print)) 951 GIOVANNA (First name (print)) 954 Vice President, Corporate Tax (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 2013-11-29 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (416) 345-6778 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 Selma Yam Name (print) 959 (416) 345-6827 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

Privacy Act, Personal Information Bank number CRA PPU 047

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Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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. 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.
- 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.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [X] 2 No [ ]

* 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 [ ]

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:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [ ]

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 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [X] 2 No [ ]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [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 (other than trade receivables)? . . . . . 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
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				715,219,447 A
Add:				
Provision for income taxes – current		101	133,186,758	
Provision for income taxes – deferred		102	-10,152,308	
Interest and penalties on taxes		103	187,585	
Amortization of tangible assets		104	581,587,830	
Amortization of intangible assets		106	46,803,054	
Charitable donations and gifts from Schedule 2		112	381,250	
Taxable capital gains from Schedule 6		113	44,665	
Scientific research expenditures deducted per financial statements		118	4,100,229	
Non-deductible meals and entertainment expenses		121	5,660,019	
Reserves from financial statements – balance at the end of the year		126	1,803,142,405	
Subtotal of additions			2,564,941,487 ▶	2,564,941,487
Other additions:				
Capital items expensed		206	14,111,325	
Debt issue expense		208	3,164,134	
Miscellaneous other additions:				
600 Other Adds - See attached schedule		290	3,771,286	
601 Amortization of WSIB gain deducted in income		291	37,910	
603 Federal apprenticeship credit prior year	570,160			
Total	570,160	293	570,160	
604				
CCRA True up	8,390,000			
Legal Fees	1,180,012			
Restricted Transmission Asset Depreciation	16,349,517			
Capital Contributions received 12(1)(x)	146,919,020			
Total	172,838,549	294	172,838,549	
Subtotal of other additions		199	194,493,364 ▶	194,493,364
Total additions		500	2,759,434,851 ▶	2,759,434,851 B
Amount A **plus** amount B				3,474,654,298

Deduct:

Capital cost allowance from Schedule 8		403	778,988,367	
Cumulative eligible capital deduction from Schedule 10		405	11,866,096	
Deferred and prepaid expenses		409	9,824,255	
SR&ED expenditures claimed in the year from Form T661 (line 460)		411	24,464,944	
Reserves from financial statements – balance at the beginning of the year		414	1,418,705,936	
Subtotal of deductions			2,243,849,598 ▶	2,243,849,598

Other deductions:

Miscellaneous other deductions:

700	Interest cap for acct, exp for tax (761401-13)		390	57,972,620	
701	Capital Contributions - 13(7.4) election		391	146,919,020	
702	US GAAP Valuation Adjust for OPEB		392	318,872,980	
703	Deduct OPEB costs capitalized in Sch013 addback	52,921,605			
	Total	52,921,605	393	52,921,605	
704	Other deductions (see attached)	160,814,950			
	Reverse insurance proceeds taken into income	4,119,057			
	2011 Prov to return for ONT ITC in OMA	881,168			
	2012 OMA in excess of Ont Co -op Credit	34,418			
	2012 OMA in excess of Ont Apprent Credit	332,854			
	Total	166,182,447	394	166,182,447	
	Subtotal of other deductions		499	742,868,672 ▶	742,868,672
	Total deductions		510	2,986,718,270 ▶	2,986,718,270

Net income (loss) for income tax purposes – enter on line 300 of the T2 return . . . 487,936,028

Attached Schedule with Total

Line 409 – Deferred and prepaid expenses

Title D-Sch 001 - Deferred or prepaid expenses deducted for tax(line 409)

Description	Amount	
Def Underwriting costs deductible for tax	4,114,000	00
Def Prospectus fees deductible for tax	153,783	00
Upfront Loan Fee Deductible for tax	318,320	00
Bond Discount	5,178,000	00
Deductible Legal fees for Deferred financing	60,152	00
Total	9,824,255	00

Attached Schedule with Total

Line 208 – Debt issue expense

Title B-Sch 001- Debt issue expenses added back for tax (line 208)

Description	Amount	
Amortization of underwrinting fee (GL #761780)	2,447,153	00
Amortization of Prospectus fees (GL #761790)	251,945	00
Amortization of Upfront Loan Fee (included in GL #761730)	203,256	00
Amortization of Hedge Loss (GL# 761770)	261,780	00
Total	3,164,134	00

Attached Schedule with Total

Line 704 – Amount

Title 704.1 - Amount for line 704.1

Description	Amount	
Removal Costs	9,688,207	00
Reverse environmental interest reflected on S-13	10,611,339	00
Capitalized Overhead general and administration	53,590,438	00
Pension Cost Deductions	86,206,761	00
Landscaping adjustments	478,613	00
Amortization of Capital contribution (741701)	177,319	00
Mark to Market	62,273	00
Total	160,814,950	00

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Amount	
Computer system software (AC 620040)	37,402	00
Computer Application Software (AC 620046)	13,515,857	00
Equipment under 2k (AC 620510)	558,066	00
Total	14,111,325	00

Attached Schedule with Total

Line 290 – Amount for line 600

Title Line 290 – Amount for line 600

Description	Amount	
Reverse environmental valuation reflected on S(13)	1,071,550	00
Bond Premium/Discount amortization (761120,761130)	2,495,262	00
ARO Interest Accretion	204,474	00
Total	3,771,286	00

Attached Schedule with Total

Line 391 – Amount for line 701

Title Line 391 – Amount for line 701

Explanatory note

Included in this return is an election under subsection 13(7.4) with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount in respect of which the election was made, and so was not included in income but was the amount by which the cost of depreciable property was reduced, is $146,919,020

Description	Amount	
Subsection 13(7.4) Election	146,919,020	00
Total	146,919,020	00

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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
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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*.
- Column A – Enter "X" if dividends received from a foreign source (connected corporation only).
- Column F1 – Enter the amount of dividends received reported in column 240 that are eligible.
- Column F2 – Enter the code that applies to the deductible taxable dividend.
- Column F3 – Enter if dividends have been received or not after December 20, 2012. This information is required for corporations that must complete Schedules 71 and 72. For more details with regards to this column, consult the Help.

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 (See note) 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. For more details, consult the Help.

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	F3	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	Business Number	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD (See note)	Taxable dividends paid to connected corporations	Eligible dividends (included in column D)
	400	410	420	430	
1	Hydro One Inc.	86999 4731 RC0001	2012-12-31	270,455,293	

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. For more details, consult the Help.

Total 270,455,293

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	270,455,293

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)				270,455,293
Other dividends paid in the tax year (total of 510 to 540)				
Total dividends paid in the tax year			500	270,455,293
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				270,455,293

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Schedule 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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).

** 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
487,554,778		487,554,778	56,033,799

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	56,068,799			
Deduct: Ontario small business deduction (from Schedule 500)	402	35,000			
Subtotal		56,033,799	▶	56,033,799	A6
Add:					
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)				56,033,799	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	10,673			
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal		10,673	▶	10,673	D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				56,023,126	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			1,221,589	
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				54,801,537	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")				54,801,537	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			▶		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				54,801,537	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	1,114,901			
Ontario apprenticeship training tax credit (from Schedule 552)	454	4,878,911			
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	187,375			
Other Ontario tax credits					
Subtotal		6,181,187	▶	6,181,187	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			48,620,350	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	48,620,350

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 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act* if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation – Income Tax Guide.*

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 1 Yes [ ] 2 No [X] If **yes**, attach a statement specifying which properties are subject to such a designation.

Part 1 – Shares

No. of shares 100	Name of corporation 105	Class of shares 106	Date of acquisition YYYY/MM/DD 110	Proceeds of disposition 120	Adjusted cost base 130	Outlays and expenses (dispositions) 140	Gain (or loss) (column 120 **minus** cols. 130 and 140) 150	Foreign source
			Totals					

Total adjustment under subsection 112(3) of the Act to all losses identified in Part 1 . . . . 160 ______

Actual gain or loss from the disposition of shares (total of line 150 **plus** line 160) . . . . ______ A

Part 2 – Real estate (Do not include losses on depreciable property.)

	Municipal address 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	Date of acquisition YYYY/MM/DD 210	Proceeds of disposition 220	Adjusted cost base 230	Outlays and expenses (dispositions) 240	Gain (or loss) (column 220 **minus** cols. 230 and 240) 250	Foreign source
1	Lot 30 Concession 2 North of Dundas Street Oakville ON CA	1973-07-05	92,400	748		91,652	
2	366 Fourth Avenue Matheson ON CA	1950-07-05	1,230	3,553		-2,323	
		Totals	93,630	4,301		89,329	B

Part 3 – Bonds

Face value 300	Maturity date 305	Name of issuer 307	Date of acquisition YYYY/MM/DD 310	Proceeds of disposition 320	Adjusted cost base 330	Outlays and expenses (dispositions) 340	Gain (or loss) (column 320 **minus** cols. 330 and 340) 350	Foreign source
			Totals					C

Part 4 – Other properties (Do not include losses on depreciable property.)

Description 400	Date of acquisition YYYY/MM/DD 410	Proceeds of disposition 420	Adjusted cost base 430	Outlays and expenses (dispositions) 440	Gain (or loss) (column 420 **minus** cols. 430 and 440) 450	Foreign source
	Totals					D

Note:
Other property includes capital debts established as bad debts, as well as amounts that arise from foreign currency transactions.

Part 5 – Personal-use property (Do not include listed personal property.)

Description 500	Date of acquisition YYYY/MM/DD 510	Proceeds of disposition 520	Adjusted cost base 530	Outlays and expenses (dispositions) 540	Gain only (column 520 **minus** cols. 530 and 540) 550	Foreign source
	Totals					E

Note:
You cannot deduct losses on dispositions of personal-use property (other than listed personal property) from your income.

Part 6 – Listed personal property

Description 600	Date of acquisition YYYY/MM/DD 610	Proceeds of disposition 620	Adjusted cost base 630	Outlays and expenses (dispositions) 640	Gain (or loss) (column 620 **minus** cols. 630 and 640) 650	Foreign source
	Totals					

Subtract: Unapplied listed personal property losses from other years 655 ______

Net gains (or losses) ______ F

Note:
Net listed personal property losses can only be applied against listed personal property gains.

The amount on line 655 is from line 530 in Part 5 of Schedule 4, *Corporation Loss Continuity and Application*.

Part 7 – Determining allowable business investment losses

Property qualifying for and resulting in an allowable business investment loss

Name of small business corporation 900	Shares, enter 1; debt, enter 2 905	Date of acquisition YYYY/MM/DD 910	Proceeds of disposition 920	Adjusted cost base 930	Outlays and expenses (dispositions) 940	Loss only (column 920 **minus** cols. 930 and 940) 950	Foreign source
		Totals					G

ABILs . . . . Amount G ______ x 50.0000 % = ______ H

(enter amount H on line 406 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*)

Note:
Properties listed in Part 7 should not be included in any other parts of Schedule 6.

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F if the amount is a loss) . . . . 89,329 I

Add: Foreign source

Capital gains dividend received in the year . . . . 875 ______ J ☐

Capital gains reserve opening balance (from Schedule 13) . . . . 880 ______ K

Subtotal (**add** amounts I, J, and K) 89,329 L

Deduct:
Capital gains reserve closing balance (from Schedule 13) . . . . 885 ______ M

Capital gains or losses, excluding ABILs (amount L **minus** amount M) 890 89,329

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 above) . . . 89,329 N

Deduct the following gains that are included in amount N:

Gain on donation of a share, debt obligation, or right listed on a designated stock exchange and other amounts under paragraph 38(a.1) of the Act

					Foreign source
realized before May 2, 2006		x 50.0000 % =		O	☐
realized after May 1, 2006				P	☐
	Subtotal (O **plus** P)	**895**			

Gain on donation of ecologically sensitive land

					Foreign source
realized before May 2, 2006		x 50.0000 % =		Q	☐
realized after May 1, 2006				R	☐
	Subtotal (Q **plus** R)	**896**			

Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under paragraph 38(*a.3*) . . . R-2 Foreign source ☐

Total (line 895 **plus** line 896 **plus** line R-2) S

Total capital gains or losses (amount N **minus** amount S) 89,329 T

Note:
If amount T is a loss, enter it on line 210 of Schedule 4.

Taxable capital gains: If amount T is a gain, enter it on this line and **multiply** . . . 89,329 x 50.0000 % = 44,665 U

(Enter amount U on line 113 of Schedule 1.)

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

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		4,143,326,853	2,213,441		35,468	1,088,987	4,144,415,839	4	0	0	165,776,634	3,979,728,192
2.	2		995,613,935			0		995,613,935	6	0	0	59,736,836	935,877,099
3.	3		243,463,461	23,532,309		0	11,766,155	255,229,615	5	0	0	12,761,481	254,234,289
4.	6		78,945,761	7,169,337		0	3,584,669	82,530,429	10	0	0	8,253,043	77,862,055
5.	7		41,097			0		41,097	15	0	0	6,165	34,932
6.	8		105,407,469	90,782,021	-17,024,891	42,203	45,369,909	133,752,487	20	0	0	26,750,497	152,371,899
7.	9		3,819,660			0		3,819,660	25	0	0	954,915	2,864,745
8.	10		147,172,455	49,381,134		972,665	24,204,235	171,376,689	30	0	0	51,413,007	144,167,917
9.	12		21,572,973	38,633,134		0	19,316,567	40,889,540	100	0	0	40,889,540	19,316,567
10.	13	Leases	1,238,740	40,247		0	20,124	1,258,863	NA	0	0	447,407	831,580
11.	17		40,686,432	17,191,345		0	8,595,673	49,282,104	8	0	0	3,942,568	53,935,209
12.	35		316,772			0		316,772	7	0	0	22,174	294,598
13.	42		85,123,234	13,940,038		0	6,970,019	92,093,253	12	0	0	11,051,190	88,012,082
14.	45	Computers - old cl.10 post Mar 2	1,869,586			0		1,869,586	45	0	0	841,314	1,028,272
15.	46	cl.8 post Mar 22/04	3,361,207	3,391,569		0	1,695,785	5,056,991	30	0	0	1,517,097	5,235,679
16.	47	Electricity Assets > 22-02-2005	3,552,838,272	1,093,702,252	7,896,677	40,175	546,831,039	4,107,565,987	8	0	0	328,605,279	4,325,791,747
17.	50	Computers	77,691,878	100,554,667	-8,971,377	0	50,277,334	118,997,834	55	0	0	65,448,809	103,826,359
18.	52					0			100	0	0		
19.	13	Barrie Office (WBS 700004578)	946,800			0		946,800	NA	0	0	210,400	736,400
20.	13	Atrium on Bay (WBS 300040666)	156,641			0		156,641	NA	0	0	28,480	128,161
21.	13	Newmarket Garage (WBS 30004(	220,136			0		220,136	NA	0	0	33,867	186,269
22.	13	255 Matheson Mississauga (WBS	1,955,748			0		1,955,748	NA	0	0	260,766	1,694,982
23.	13	95 Mural Street (WBS 70001035!	39,580			0		39,580	NA	0	0	8,796	30,784
24.	13	Nipigon (WBS 700011829)		201,080		0	100,540	100,540	NA	0	0	12,568	188,512

	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
25.	13	Kemptville (WBS 700009832)		12,082		0	6,041	6,041	NA	0	0	1,208	10,874
26.	13	Sudbury (WBS 700010356)		326,876		0	163,438	163,438	NA	0	0	11,674	315,202
27.	13	Lionhead (WBS 700015140)		47,742		0	23,871	23,871	NA	0	0	2,652	45,090
		Totals	9,505,808,690	1,441,119,274	-18,099,591	1,090,511	720,014,386	10,207,723,476				778,988,367	10,148,749,495

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
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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.	Hydro One Inc.		86999 4731 RC0001	1					
2.	Hydro One Remote Communities In		87083 6269 RC0001	3					
3.	Hydro One Telecom Inc.		86800 1066 RC0001	3					
4.	Hydro One Telecom Link Limited		88786 7513 RC0001	3					
5.	Hydro One Brampton Networks Inc.		86486 7635 RC0001	3					
6.	Hydro One Lake Erie Link Managem		87892 1519 RC0001	3					
7.	Hydro One Lake Erie Link Company		87560 6519 RC0001	3					

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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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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

		Line	Amount		Amount		Line	Amount	
Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")							200	86,905,442	A
Add:	Cost of eligible capital property acquired during the taxation year	222	110,146,946						
	Other adjustments	226							
	Subtotal (line 222 plus line 226)		110,146,946	x 3 / 4 =	82,610,210	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")				82,610,210	▶		82,610,210	D
	Amount transferred on amalgamation or wind-up of subsidiary						224		E
	Subtotal (add amounts A, D, and E)						230	169,515,652	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)								169,515,652	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business				249					
	amount K		169,515,652						
	less amount from line 249								
Current year deduction			169,515,652	x 7.00 % = 250	11,866,096	*			
	(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				11,866,096	▶		11,866,096	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")							300	157,649,556	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	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability Short Term	42,382,000				42,382,000
2	OPEB Liability Long Term	1,017,403,496		372,271,172		1,389,674,668
3	Enviromental Short Term	18,857,648		1,704,598		20,562,246
4	Environmental Long Term	223,394,118			7,248,662	216,145,456
5	Contingent Liabilities	8,843,268		2,388,884		11,232,152
6	Regulatory Accounts	95,845,860	889,507	17,191,480		113,926,847
7	Tenant Inducement	1,977,308			1,871,003	106,305
8	Asset Retirement Obligations	9,112,731				9,112,731
	Reserves from Part 2 of Schedule 13					
	Totals	1,417,816,429	889,507	393,556,134	9,119,665	1,803,142,405

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc.	483 Bay Street Toronto ON CA M5G 2P5			4,954,510		

T2 SCH 14 (99)

Canada

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SCHEDULE 15

DEFERRED INCOME PLANS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments,* Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) filed by: (see note 3) (EPSP only) 600
1	1	158,760,150	1059104			

Note 1: Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP

Note 2: You do not need to add to Schedule 1 any payments you made to deferred income plans. To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	158,760,150	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	158,760,150	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")		C

Enter amount C on line 417 of Schedule 1

Note 3: T4PS slip(s) filed by: 1 – Trustee
2 – Employer

T2 SCH 15 (06)

Canada

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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
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 2012

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 ☒

	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	Hydro One Networks Inc.	87086 5821 RC0001	1	500,000	100.0000	500,000
2	Hydro One Inc.	86999 4731 RC0001	1	500,000		
3	Hydro One Remote Communities Inc.	87083 6269 RC0001	1	500,000		
4	Hydro One Telecom Inc.	86800 1066 RC0001	1	500,000		
5	Hydro One Telecom Link Limited	88786 7513 RC0001	1	500,000		
6	Hydro One Brampton Networks Inc.	86486 7635 RC0001	1	500,000		
7	Hydro One Lake Erie Link Management Inc	87892 1519 RC0001	1	500,000		
8	Hydro One Lake Erie Link Company Inc.	87560 6519 RC0001	1	500,000		
				Total	100.0000	500,000 **A**

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer 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*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- 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.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). 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).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see the section called "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release*.*
- For more information on SR&ED, see 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.* Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), 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.
- 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.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- 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 it incurred the expenditures or capital costs.
- 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 ITCs 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 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, *Guide for the Partnership Information Return*.
- 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.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more details.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more details.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.
- For the purpose of this schedule, **pre-production mining development expenditures** are expenses incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more details.

Part 1 – Investments, expenditures and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
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 and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
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 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a phase of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more details.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more details. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

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 its 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.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

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.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource 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**
			Total of investments for qualified property and qualified resource property	A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year . . . B

Deduct:

Credit deemed as a remittance of co-op corporations . . . 210

Credit expired . . . 215

Subtotal (line 210 **plus** line 215) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) . . . 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary . . . 230

ITC from repayment of assistance . . . 235

Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) . . . x 10 % = 240

Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) . . . x 5 % = 242

Credit allocated from a partnership . . . 250

Subtotal (total of lines 230 to 250) ▶ D

Total credit available (line 220 **plus** amount D) . . . E

Deduct:

Credit deducted from Part I tax (enter at amount D in Part 30) . . . 260

Credit carried back to the previous year(s) (amount H from Part 6) . . . a

Credit transferred to offset Part VII tax liability . . . 280

Subtotal (total of line 260, amount a, and line 280) ▶ F

Credit balance before refund (amount E **minus** amount F) . . . G

Deduct:

Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7) . . . 310

ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310) 320

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource 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 at amount a in Part 5) H

Part 7 – Refund for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5) . . . I

Credit balance before refund (amount G from Part 5) . . . J

Refund (40 % of amount I or J, whichever is less) . . . K

Enter amount K 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)	27,240,658			
Add:				
Contributions to agricultural organizations for SR&ED*				
Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)*	27,240,658	▶	350	27,240,658
Capital expenditures incurred **before** 2014 (from line 558 on Form T661)**			360	400,975
Repayments made in the year (from line 560 on Form T661)			370	
Qualified SR&ED expenditures (total of lines 350 to 370)			380	27,641,633

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

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 [X] 2 No [ ]

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 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation:		$ 8,000,000	
Deduct:			
Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more	x 10 =		A
Excess ($8,000,000 **minus** amount A; if negative, enter "0")			B
$ 40,000,000 **minus** line 398 from Part 9	a		
Amount a **divided** by $ 40,000,000			C
Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C)			D*
For an associated corporation:			
If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49	400		E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E ______ x $\frac{\text{Number of days in the tax year}}{365}$ 366 = ______ F

Your SR&ED expenditure limit for the year (enter the amount from line D, E, or F, whichever applies) **410** ______

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x	35 % =		G
Line 350 **minus** line 410 (if negative, enter "0")**	430	27,240,658	x	20 % =	5,448,132	H
Line 410 **minus** line 350 (if negative, enter "0")			b			
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x	35 % =		I
Line 360 **minus** amount b above (if negative, enter "0")**	450	400,975	x	20 % =	80,195	J
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 % =		c	
480		x	20 % =		d	
Subtotal (amount c **plus** amount d)					▶	K

Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12) . . . 5,528,327 L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					M
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
Subtotal (line 510 **plus** line 515)			▶		N
ITC at the beginning of the tax year (amount M **minus** amount N)			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit (from amount L in Part 11)	540	5,528,327			
Credit allocated from a partnership	550				
Subtotal (total of lines 530 to 550)		5,528,327	▶	5,528,327	O
Total credit available (line 520 **plus** amount O)				5,528,327	P
Deduct:					
Credit deducted from Part I tax (enter at amount E in Part 30)	560	5,528,327			
Credit carried back to the previous year(s) (amount S from Part 13)			e		
Credit transferred to offset Part VII tax liability	580				
Subtotal (total of line 560, amount e, and line 580)		5,528,327	▶	5,528,327	Q
Credit balance before refund (amount P **minus** amount Q)					R
Deduct:					
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED (amount R **minus** line 610)			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 at amount e in Part 12)			S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) ____ f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* ____ T

Deduct:

Amount T or amount G from Part 11, whichever is less ____ U

Net amount (amount T **minus** amount U; if negative, enter "0") ____ V

Amount V **multiplied** by 40 % ____ W

Add:

Amount U ____ X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) ____ Y

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 for amount Y.

Part 15 – 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 at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) ____ Z

Deduct:

Amount Z or amount G from Part 11, whichever is less ____ AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") ____ BB

Amount BB or amount I from Part 11, whichever is less ____ CC

Amount CC **multiplied** by 40 % ____ DD

Add :

Amount AA ____ EE

Refund of ITC (amount DD **plus** amount EE) ____ FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – 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

Subtotal (enter this amount at amount C in Part 17) ______ A

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 in amount B in Part 16 on page 9.

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

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 in amount B 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

Subtotal (enter this amount at amount D in Part 17) ______ B

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 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ____________

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from amount A in Part 16		C
Recaptured ITC for calculation 2 from amount B in Part 16		D
Recaptured ITC for calculation 3 from line 760 in Part 16		E
Total recapture of SR&ED investment tax credit – total of amounts C to E		F

Enter amount F at amount A 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.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

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	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

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	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826 ► A

Total pre-production mining expenditures (total of lines 810 to 821 and amount A)	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")			B
Add:			
Repayments of government and non-government assistance	835		
Pre-production mining expenditures (amount B **plus** line 835)			C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year .... D

Deduct:

Credit deemed as a remittance of co-op corporations 841

Credit expired 845

Subtotal (line 841 **plus** line 845) ▶ E

ITC at the beginning of the tax year (amount D **minus** amount E) 850

Add:

Credit transferred on amalgamation or wind-up of subsidiary 860

Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18) .. 870 x 10 % = a

Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18) .. 872 x 5 % = b

Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18) .. 874 x 7 % = c

Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18) .. 876 x 4 % = d

Current year credit (total of amounts a to d) 880 ▶ F

Total credit available (total of lines 850, 860, and amount F) .... G

Deduct:

Credit deducted from Part I tax (enter at amount F in Part 30) 885

Credit carried back to the previous year(s) (amount I from Part 20) .... e

Subtotal (line 885 **plus** amount e) ▶ H

ITC closing balance from pre-production mining expenditures (amount G **minus** amount H) 890

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	

Total (enter at amount e in Part 19) I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) .... 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	Apprentice 1	309A	43,769	4,377	2,000
2.	Apprentice 2	434A	3,560	356	356

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
3.	Apprentice 3	309A	53,160	5,316	2,000
4.	Apprentice 4	309A	4,080	408	408
5.	Apprentice 5	310T	67,569	6,757	2,000
6.	Apprentice 6	310T	900	90	90
7.	Apprentice 7	310T	2,420	242	242
8.	Apprentice 8	309A	78,732	7,873	2,000
9.	Apprentice 9	434A	20,978	2,098	2,000
10.	Apprentice 10	434A	6,010	601	601
11.	Apprentice 11	434A	5,490	549	549
12.	Apprentice 12	434A	6,430	643	643
13.	Apprentice 13	434A	4,980	498	498
14.	Apprentice 14	434A	3,870	387	387
15.	Apprentice 15	434A	1,710	171	171
16.	Apprentice 16	434A	6,630	663	663
17.	Apprentice 17	434A	4,270	427	427
18.	Apprentice 18	434A	6,220	622	622
19.	Apprentice 19	434A	4,310	431	431
20.	Apprentice 20	434A	5,130	513	513
21.	Apprentice 21	309A	10,150	1,015	1,015
22.	Apprentice 22	434A	44,489	4,449	2,000
23.	Apprentice 23	434A	45,588	4,559	2,000
24.	Apprentice 24	309A	43,918	4,392	2,000
25.	Apprentice 25	309A	52,374	5,237	2,000
26.	Apprentice 26	309A	12,000	1,200	1,200
27.	Apprentice 27	309A	10,550	1,055	1,055
28.	Apprentice 28	309A	9,310	931	931
29.	Apprentice 29	309A	11,580	1,158	1,158
30.	Apprentice 30	434A	42,193	4,219	2,000
31.	Apprentice 31	434A	45,545	4,555	2,000
32.	Apprentice 32	309A	8,307	831	831
33.	Apprentice 33	309A	60,854	6,085	2,000
34.	Apprentice 34	309A	14,320	1,432	1,432
35.	Apprentice 35	309A	20,513	2,051	2,000
36.	Apprentice 36	309A	25,772	2,577	2,000
37.	Apprentice 37	309A	27,683	2,768	2,000
38.	Apprentice 38	309A	17,456	1,746	1,746
39.	Apprentice 39	434A	44,243	4,424	2,000
40.	Apprentice 40	434A	41,895	4,190	2,000
41.	Apprentice 41	309A	35,668	3,567	2,000
42.	Apprentice 42	309A	43,738	4,374	2,000
43.	Apprentice 43	434A	18,901	1,890	1,890
44.	Apprentice 44	309A	61,817	6,182	2,000
45.	Apprentice 45	309A	36,971	3,697	2,000
46.	Apprentice 46	309A	43,042	4,304	2,000
47.	Apprentice 47	309A	28,161	2,816	2,000
48.	Apprentice 48	309A	35,775	3,578	2,000
49.	Apprentice 49	309A	20,978	2,098	2,000
50.	Apprentice 50	309A	11,918	1,192	1,192
51.	Apprentice 51	434A	56,169	5,617	2,000
52.	Apprentice 52	434A	46,218	4,622	2,000
53.	Apprentice 53	434A	68,437	6,844	2,000
54.	Apprentice 54	434A	66,984	6,698	2,000
55.	Apprentice 55	434A	58,216	5,822	2,000
56.	Apprentice 56	434A	75,003	7,500	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
57.	Apprentice 57	434A	64,900	6,490	2,000
58.	Apprentice 58	434A	58,362	5,836	2,000
59.	Apprentice 59	434A	63,865	6,387	2,000
60.	Apprentice 60	434A	54,663	5,466	2,000
61.	Apprentice 61	434A	59,554	5,955	2,000
62.	Apprentice 62	434A	50,391	5,039	2,000
63.	Apprentice 63	434A	66,270	6,627	2,000
64.	Apprentice 64	434A	67,159	6,716	2,000
65.	Apprentice 65	434A	55,419	5,542	2,000
66.	Apprentice 66	309A	20,570	2,057	2,000
67.	Apprentice 67	309A	23,111	2,311	2,000
68.	Apprentice 68	434A	66,456	6,646	2,000
69.	Apprentice 69	434A	4,896	490	490
70.	Apprentice 70	434A	64,229	6,423	2,000
71.	Apprentice 71	434A	61,829	6,183	2,000
72.	Apprentice 72	434A	67,604	6,760	2,000
73.	Apprentice 73	434A	58,575	5,858	2,000
74.	Apprentice 74	434A	59,294	5,929	2,000
75.	Apprentice 75	434A	56,960	5,696	2,000
76.	Apprentice 76	434A	62,796	6,280	2,000
77.	Apprentice 77	434A	66,351	6,635	2,000
78.	Apprentice 78	434A	63,274	6,327	2,000
79.	Apprentice 79	434A	64,073	6,407	2,000
80.	Apprentice 80	434A	56,822	5,682	2,000
81.	Apprentice 81	434A	56,805	5,681	2,000
82.	Apprentice 82	434A	59,995	6,000	2,000
83.	Apprentice 83	434A	56,751	5,675	2,000
84.	Apprentice 84	434A	38,975	3,898	2,000
85.	Apprentice 85	434A	16,682	1,668	1,668
86.	Apprentice 86	310T	49,033	4,903	2,000
87.	Apprentice 87	310T	54,676	5,468	2,000
88.	Apprentice 88	310T	44,490	4,449	2,000
89.	Apprentice 89	310T	61,018	6,102	2,000
90.	Apprentice 90	309A	44,463	4,446	2,000
91.	Apprentice 91	309A	56,084	5,608	2,000
92.	Apprentice 92	309A	57,396	5,740	2,000
93.	Apprentice 93	309A	55,559	5,556	2,000
94.	Apprentice 94	309A	45,165	4,517	2,000
95.	Apprentice 95	309A	64,467	6,447	2,000
96.	Apprentice 96	309A	48,646	4,865	2,000
97.	Apprentice 97	309A	61,982	6,198	2,000
98.	Apprentice 98	309A	42,318	4,232	2,000
99.	Apprentice 99	309A	11,510	1,151	1,151
100	Apprentice 100	309A	55,449	5,545	2,000
101	Apprentice 101	309A	78,302	7,830	2,000
102	Apprentice 102	309A	58,614	5,861	2,000
103	Apprentice 103	309A	41,285	4,129	2,000
104	Apprentice 104	309A	39,233	3,923	2,000
105	Apprentice 105	309A	23,685	2,369	2,000
106	Apprentice 106	434A	5,976	598	598
107	Apprentice 107	434A	35,130	3,513	2,000
108	Apprentice 108	434A	51,069	5,107	2,000
109	Apprentice 109	434A	45,167	4,517	2,000
110	Apprentice 110	434A	51,229	5,123	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
111	Apprentice 111	434A	53,380	5,338	2,000
112	Apprentice 112	434A	45,103	4,510	2,000
113	Apprentice 113	434A	51,227	5,123	2,000
114	Apprentice 114	434A	55,572	5,557	2,000
115	Apprentice 115	434A	42,557	4,256	2,000
116	Apprentice 116	434A	46,024	4,602	2,000
117	Apprentice 117	434A	50,056	5,006	2,000
118	Apprentice 118	434A	33,122	3,312	2,000
119	Apprentice 119	434A	46,252	4,625	2,000
120	Apprentice 120	434A	58,173	5,817	2,000
121	Apprentice 121	434A	47,930	4,793	2,000
122	Apprentice 122	434A	43,814	4,381	2,000
123	Apprentice 123	434A	43,057	4,306	2,000
124	Apprentice 124	309A	50,182	5,018	2,000
125	Apprentice 125	309A	39,030	3,903	2,000
126	Apprentice 126	309A	47,851	4,785	2,000
127	Apprentice 127	434A	45,288	4,529	2,000
128	Apprentice 128	434A	52,788	5,279	2,000
129	Apprentice 129	434A	42,726	4,273	2,000
130	Apprentice 130	434A	66,926	6,693	2,000
131	Apprentice 131	434A	45,475	4,548	2,000
132	Apprentice 132	434A	45,186	4,519	2,000
133	Apprentice 133	434A	41,307	4,131	2,000
134	Apprentice 134	434A	34,123	3,412	2,000
135	Apprentice 135	434A	46,834	4,683	2,000
136	Apprentice 136	434A	46,658	4,666	2,000
137	Apprentice 137	434A	41,456	4,146	2,000
138	Apprentice 138	434A	41,505	4,151	2,000
139	Apprentice 139	434A	42,781	4,278	2,000
140	Apprentice 140	434A	52,579	5,258	2,000
141	Apprentice 141	434A	39,599	3,960	2,000
142	Apprentice 142	434A	44,796	4,480	2,000
143	Apprentice 143	434A	43,603	4,360	2,000
144	Apprentice 144	309A	9,098	910	910
145	Apprentice 145	309A	30,993	3,099	2,000
146	Apprentice 146	309A	31,603	3,160	2,000
147	Apprentice 147	309A	32,211	3,221	2,000
148	Apprentice 148	309A	33,680	3,368	2,000
149	Apprentice 149	309A	22,330	2,233	2,000
150	Apprentice 150	309A	28,436	2,844	2,000
151	Apprentice 151	309A	30,127	3,013	2,000
152	Apprentice 152	434A	31,827	3,183	2,000
153	Apprentice 153	434A	51,467	5,147	2,000
154	Apprentice 154	434A	49,547	4,955	2,000
155	Apprentice 155	434A	30,041	3,004	2,000
156	Apprentice 156	434A	30,270	3,027	2,000
157	Apprentice 157	434A	35,491	3,549	2,000
158	Apprentice 158	309A	38,085	3,809	2,000
159	Apprentice 159	434A	35,914	3,591	2,000
160	Apprentice 160	434A	27,283	2,728	2,000
161	Apprentice 161	434A	41,219	4,122	2,000
162	Apprentice 162	434A	36,066	3,607	2,000
163	Apprentice 163	434A	45,832	4,583	2,000
164	Apprentice 164	434A	35,188	3,519	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
165	Apprentice 165	434A	37,107	3,711	2,000
166	Apprentice 166	310T	24,917	2,492	2,000
167	Apprentice 167	310T	22,857	2,286	2,000
168	Apprentice 168	310T	21,860	2,186	2,000
169	Apprentice 169	434A	31,465	3,147	2,000
170	Apprentice 170	434A	38,149	3,815	2,000
171	Apprentice 171	434A	49,404	4,940	2,000
172	Apprentice 172	434A	34,190	3,419	2,000
173	Apprentice 173	434A	53,737	5,374	2,000
174	Apprentice 174	434A	35,821	3,582	2,000
175	Apprentice 175	434A	33,869	3,387	2,000
176	Apprentice 176	434A	29,535	2,954	2,000
177	Apprentice 177	434A	41,231	4,123	2,000
178	Apprentice 178	434A	44,022	4,402	2,000
179	Apprentice 179	434A	29,511	2,951	2,000
180	Apprentice 180	434A	51,117	5,112	2,000
181	Apprentice 181	434A	27,923	2,792	2,000
182	Apprentice 182	434A	29,626	2,963	2,000
183	Apprentice 183	309A	15,332	1,533	1,533
184	Apprentice 184	309A	16,248	1,625	1,625
185	Apprentice 185	309A	10,905	1,091	1,091
186	Apprentice 186	309A	12,372	1,237	1,237
187	Apprentice 187	309A	15,478	1,548	1,548
188	Apprentice 188	309A	15,331	1,533	1,533
189	Apprentice 189	309A	11,189	1,119	1,119
190	Apprentice 190	309A	8,009	801	801
191	Apprentice 191	309A	5,822	582	582
192	Apprentice 192	309A	6,816	682	682
193	Apprentice 193	309A	8,209	821	821
194	Apprentice 194	309A	6,686	669	669
195	Apprentice 195	309A	7,562	756	756
196	Apprentice 196	434A	5,421	542	542
197	Apprentice 197	434A	6,150	615	615
198	Apprentice 198	434A	5,608	561	561
199	Apprentice 199	434A	6,150	615	615
200	Apprentice 200	434A	4,698	470	470
201	Apprentice 201	434A	5,815	582	582
202	Apprentice 202	434A	5,172	517	517
203	Apprentice 203	434A	5,793	579	579

Total current-year credit (enter at line 640 in Part 22) 346,346 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year					B
Deduct:					
Credit deemed as a remittance of co-op corporations	612				
Credit expired after 20 tax years	615				
Subtotal (line 612 **plus** line 615)			▶		C
ITC at the beginning of the tax year (amount B **minus** amount C)			625		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	630				
ITC from repayment of assistance	635				
Total current-year credit (amount A from Part 21)	640	346,346			
Credit allocated from a partnership	655				
Subtotal (total of lines 630 to 655)		346,346	▶	346,346	D
Total credit available (line 625 **plus** amount D)				346,346	E
Deduct:					
Credit deducted from Part I tax (enter at amount G in Part 30)	660	346,346			
Credit carried back to the previous year(s) (amount G from Part 23)			a		
Subtotal (line 660 **plus** amount a)		346,346	▶	346,346	F
ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F)			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 at amount a in Part 22)		G

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 ____

Add:

Specified child care start-up expenditures from the current tax year . . . . . 705 ____

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ____ A

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 A) . . . . . 725 ____

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . ____ B

Add:

Repayments of government and non-government assistance . . . . . 735 ____

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . . 745 ____

* CCA: capital cost allowance

Part 25 – 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 (from line 745) . . . . . ____ x 25 % = ____ C

Number of child care spaces . . . . . 755 ____ x $ 10,000 = ____ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . . ____ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G
ITC at the beginning of the tax year (amount F **minus** amount G)			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount E from Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H
Total credit available (line 775 **plus** amount H)				I
Deduct:				
Credit deducted from Part I tax (enter at amount H in Part 30)	785			
Credit carried back to the previous year(s) (amount K from Part 27)			a	
Subtotal (line 785 **plus** amount a)			▶	J
ITC closing balance from child care spaces expenditures (amount I **minus** amount J)			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year / Month / Day			
1st previous tax year	2011-12-31	Credit to be applied	941	
2nd previous tax year	2010-12-31	Credit to be applied	942	
3rd previous tax year	2009-12-31	Credit to be applied	943	
		Total (enter at amount a in Part 26)		K

Recapture – Child Care Spaces

Part 28 – 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** ______

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 . . . ______ A

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 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799) . . . ______ B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17)		A
Recaptured child care spaces ITC (from amount B in Part 28)		B
Total recapture of investment tax credit (amount A **plus** amount B)		C

Enter amount C 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)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)	5,528,327	E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	346,346	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	5,874,673	I

Enter amount I at line 652 of the T2 return.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

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	Hydro One Inc.	86999 4731 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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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
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

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

	Line	Amount	Line	Amount	
Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		270,455,293			
Total taxable dividends paid in the tax year	100	270,455,293			
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

	Line	Amount	Line	Amount	
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 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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. You do not have to file it 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, 2011 / Number of days in the tax year	/ 366	x	12.00 %	=	%	A1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	366 / 366	x	11.50 %	=	11.50000 %	A2

Ontario basic rate of tax for the year (rate A1 **plus** A2) 11.50000 ► 11.50000 % A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 487,554,778 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1) . . . . . . 56,068,799 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 or Ontario special additional tax on life insurance corporations 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)	487,891,364	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)	487,554,778	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	3
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 ** = 487,554,778.00 / 487,554,778 = 1.00000 E

Amount D x factor E 500,000 a

Ontario taxable income (amount B from Part 2) 487,554,778 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, 2011 / Number of days in the tax year = ___ / 366 x 7.50 % = ___ % G1

Number of days in the tax year after June 30, 2011 / Number of days in the tax year = 366 / 366 x 7.00 % = 7.00000 % G2

OSBD rate for the year (rate G1 **plus** G2) 7.00000 % G3

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3) 35,000 H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – 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.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3) 500,000 I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – 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		J		
Deduct:				
Ontario adjusted small business income (amount I from Part 4)		K		
Subtotal (amount J **minus** amount K) (if negative, enter "0")		L		
OSBD rate for the year (rate G3 from Part 3)	7.00000 %			
Amount L **multiplied** by the OSBD rate for the year				M
Ontario domestic factor (factor E from Part 3)			1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)				O

Enter amount O on line 410 of Schedule 5.

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SCHEDULE 506

ONTARIO TRANSITIONAL TAX DEBITS AND CREDITS

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- Complete this schedule if you are a specified corporation that is subject to the Ontario transitional tax debit or are claiming the Ontario transitional tax credit.
- Unless otherwise noted, all legislative references are to the federal *Income Tax Act*.
- File this schedule with the *T2 Corporation Income Tax Return*.
- Unless otherwise noted, terms on this page are defined under subsection 46(1) of the *Taxation Act, 2007* (Ontario).
- **Specified corporation** is defined under subsection 46(5) of the *Taxation Act, 2007* (Ontario) as a corporation:
  - that is not exempt at or immediately before its transition time from tax payable under Part I of the federal Act;
  - that has a tax year that ends before 2009 and a tax year that includes January 1, 2009; or has a tax year that begins after 2008 and a tax year that is deemed to end on December 31, 2008, under subsection 249(3) of the federal Act;
  - that has a permanent establishment (PE) in Ontario at its transition time;
  - that had a PE in Ontario at any time in its last tax year ending before 2009, and was subject to tax under Part II of the *Corporations Tax Act* (Ontario) for that tax year; and
  - whose assets have not been distributed in an eligible pre-2009 windup.
- A specified corporation also includes, under subsection 51(1) of *the Taxation Act, 2007* (Ontario), the parent corporation of an eligible post-2008 windup and the new corporation of an eligible amalgamation.
- A specified corporation may be subject to the Ontario transitional tax debit if:
  - the corporation's total federal balance is more than the total Ontario balance at the end of the tax year; or
  - the corporation has a post-2008 scientific research and experimental development (SR&ED) balance, as defined under subsection 49(2) of the *Taxation Act, 2007* (Ontario), and a federal SR&ED transitional balance, as defined under subsection 49(4) of the *Taxation Act, 2007* (Ontario), at the end of the tax year.
- A specified corporation may be able to claim the Ontario transitional tax credit if:
  - the corporation's total Ontario balance is more than the total federal balance at the end of the tax year; or
  - the corporation has an unused transitional tax credit balance from previous tax years.
- **Transition time** means:
  - the beginning of the corporation's first tax year that starts after 2008 if the previous tax year is deemed under subsection 249(3) of the federal Act to end on December 31, 2008, or
  - the beginning of the corporation's tax year that includes January 1, 2009, in any other case.
- An **eligible amalgamation** means an amalgamation or merger of a particular corporation and one or more other corporations to form a new corporation where:
  - the amalgamation or merger occurs after December 31, 2008, and does not occur at the new corporation's transition time;
  - the new corporation has a PE in Ontario immediately after the amalgamation or merger;
  - the particular corporation has a PE in Ontario immediately before the amalgamation or merger;
  - the particular corporation is a specified corporation at its transition time or at any time before the amalgamation or merger;
  - the amalgamation or merger occurs in the amortization period of the new corporation;
  - the amortization period of the new corporation does not end immediately after the beginning of its reference period; and
  - the amortization period of the particular corporation does not end before the amalgamation or merger.
- An **eligible post-2008 windup** means the windup of a subsidiary corporation into its parent corporation under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the time immediately after the completion time is within the amortization periods of the subsidiary and parent;
  - the parent's tax year (during which it received the assets of the subsidiary) ends after December 31, 2008;
  - the subsidiary has a PE in Ontario during its tax year ending at the completion time; and
  - the parent has a PE in Ontario during its tax year in which it received the assets from the subsidiary.
- An **eligible pre-2009 windup** means the windup of a subsidiary under subsection 88(1) where:
  - the completion time of the windup is after December 31, 2008, and the parent's tax year (during which it received the assets of the subsidiary) ended before January 1, 2009; or
  - the completion time of the windup is before January 1, 2009, and the parent's tax year (during which it received the assets of the subsidiary) ended after December 31, 2008.
- The **completion time** of a windup means the end of the tax year of the subsidiary during which the subsidiary distributes its assets to the parent for the purposes of paragraph 88(1)(e.2).
- A **specified pre-2009 transfer** under section 52 of the *Taxation Act, 2007* (Ontario) means a transfer of property between corporations not at arm's length that changes the total federal or Ontario balance of either the transferee or the transferor and that occurs:
  - before 2009;
  - at different values under the *Corporations Tax Act* (Ontario) and the federal Act;
  - in a tax year ending after 2008 for either the transferee or the transferor corporation, and that corporation is a specified corporation; and
  - in a tax year of the other corporation ending before 2009, in which the other corporation has a PE in Ontario.

Part 1 – Total federal balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Federal balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 220 from Schedule 8, *Capital Cost Allowance (CCA)*)	110	
Charitable donations not yet deducted from income (from line 280 of Schedule 2, *Charitable Donations and Gifts*) (see Note 1)	112	
Gifts to Canada, a province, or a territory (from line 380 of Schedule 2) (see Note 1)	114	
Gifts of certified cultural property (from line 480 of Schedule 2) (see Note 1)	116	
Gifts of certified ecologically sensitive land (from line 580 of Schedule 2) (see Note 1)	118	
Gifts of medicine (from line 680 of Schedule 2) (see Note 1)	120	
Cumulative eligible capital (from line 300 of Schedule 10, *Cumulative Eligible Capital Deduction*)	122	
Federal SR&ED expenditure pool (from line 470 of Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*) (see Note 2 and Note 3)	124	
Cumulative Canadian exploration expense (from line 249 of Schedule 12, *Resource-Related Deductions*) (see Note 2)	128	
Cumulative Canadian development expense (from line 349 of Schedule 12) (see Note 2)	130	
Cumulative Canadian oil and gas property expense (from line 449 of Schedule 12) (see Note 2)	132	

Federal balances at the beginning of the current tax year

Non-capital losses (line 102 of Schedule 4, *Corporation Loss Continuity and Application*, of the current tax year) (see Note 2 and Note 4)	134	
Net capital losses (from line 200 of Schedule 4 of the current tax year x 50 %) (see Note 2 and Note 4)	136	

Amounts included in the calculation of the Ontario income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	150	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario)	152	
Other discretionary deductions claimed for Ontario income tax, but not claimed federally in the tax years ending after December 12, 2006, and before the transition time	154	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, under the federal Act, at the beginning of the tax year (see Note 5)	160	
Gain from a negative adjusted cost base of a partnership interest under subsection 40(3) of the federal Act, as it applies under the *Corporations Tax Act* (Ontario), as if all partnership interests were disposed of at the beginning of the tax year	162	
Amount of farming income specified under paragraph 28(1)(b) in the previous tax year	164	
Federal balance before election (total of lines 110 to 164)		A

Deduct:

Lesser of amount D or amount E from Part 4, if an election is made	170	
Total federal balance (amount A **minus** line 170)	180	

Enter amount on line 300 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 2 – Total Ontario balance

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

If this is the first year after amalgamation, include the total of all amounts from the predecessor corporations that had a PE in Ontario immediately before the amalgamation.

If the corporation is a life insurer or a non-resident corporation, do not include the amounts under the additional rules in subsection 48(8) of the *Taxation Act, 2007* (Ontario).

For other tax years, go to Part 3.

Ontario balances at the end of the previous tax year (tax year ending in 2008)

Total undepreciated capital cost of depreciable properties (total of column 13 from Ontario Schedule 8, *Ontario Capital Cost Allowance*)	210	
Charitable donations (amount I from Ontario *Schedule 2, Ontario Charitable Donations and Gifts*) (see Note 1)	212	
Gifts to Canada, a province, or a territory (total of closing balance amounts from parts 3 and 5 of Ontario Schedule 2) (see Note 1)	214	
Gifts of certified cultural property (closing balance amount from Part 6 of Ontario Schedule 2) (see Note 1)	216	
Gifts of certified ecologically sensitive land (closing balance amount from Part 7 of Ontario Schedule 2) (see Note 1)	218	
Gifts of medicine (see Note 1)	220	
Cumulative eligible capital (amount Q from Ontario *Schedule 10, Ontario Cumulative Eligible Capital Deduction*)	222	
Ontario SR&ED expenditure pool (line 480 from Ontario *CT23 Schedule 161, Ontario Scientific Research and Experimental Development Expenditures*) (see Note 2 and Note 3)	224	
Adjusted Ontario SR&ED incentive balance (see Note 2 and Note 5)	226	
Cumulative Canadian exploration expense (closing balance of Regular Expenses from Part 2 of Ontario *Schedule 12, Ontario Exploration Expenses*) (see Note 2)	228	
Cumulative Canadian development expense (closing balance of Regular Expenses, Canadian CCDE Expenses, from Part 3 of Ontario Schedule 12) (see Note 2)	230	
Cumulative Canadian oil and gas property expense (closing balance of Regular Expenses from Part 4 of Ontario Schedule 12) (see Note 2)	232	
Non-capital losses (from line 709 of Ontario *Corporations Tax Return CT8* or *CT23 Corporations Tax and Annual Return*) (see Note 2 and Note 4)	234	
Net capital losses (from line 719 of CT8 or CT23 x 50 %) (see Note 2 and Note 4)	236	

Amounts included In the calculation of the federal income tax in the previous tax year

Total reserves deducted under paragraph 20(1)(l), (l.1), (m), (m.1), (n), or (o), subsection 32(1), section 61.4 or subparagraph 138(3)(a)(i), (ii), or (iv)	250	
One half of the total reserves deducted under subparagraph 40(1)(a)(iii) or 44(1)(e)(iii)	252	

Other amounts

Total adjusted cost base of partnership interests owned by the corporation, for the purposes of the *Corporations Tax Act* (Ontario), at the beginning of the tax year (see Note 6)	260	
Gain from a "negative" adjusted cost base of a partnership interest under subsection 40(3) determined as if all partnership interests were disposed of at the beginning of the tax year	262	
Amount of farming income in the previous tax year specified under paragraph 28(1)(b) of the federal Act, as it applies for the purposes of the *Corporations Tax Act* (Ontario)	264	
Total Ontario balance (total of lines 210 to 264)	280	

Enter amount on line 340 in Part 3.

Note 1: Enter "0" if the corporation was non-resident immediately before its transition time.

Note 2: Enter "0" if control of the corporation was acquired at transition time.

Note 3: Do not include the SR&ED expenditure pool earned before control of the corporation was last acquired.

Note 4: Do not include losses that arose before control of the corporation was last acquired.

Note 5: The adjusted Ontario SR&ED incentive balance under subsection 49(7) of the *Taxation Act, 2007* (Ontario) is the total of federal investment tax credits that:
- have been earned and are available without restriction to the corporation;
- are attributable to qualifying Ontario SR&ED expenditures;
- have not been deducted under subsection 127(5) or (6) of the federal Act at the end of the corporation's tax year ending immediately before its transition time; and
- do not expire in the first tax year ending in 2009 under the 10-year carryforward limit,

divided by the relevant Ontario allocation factor as calculated in Part 11.

Note 6: The adjusted cost base of any particular partnership interest cannot be less than "0".

Part 3 – Total federal balance and total Ontario balance at the end of the tax year

Total federal balance:

	Line	Amount		Line	Amount
Total federal balance (amount from line 180 in Part 1, or amount from line 330 in Part 3 of Schedule 506 for the previous tax year)	300	8,347,715,889			
Add:					
Amount from eligible amalgamation*	310				
Amount from eligible post-2008 windup*	315				
Amount from eligible pre-2009 windup*	320				
Amount from specified pre-2009 transfers*	325				
Total federal balance at the end of the tax year		8,347,715,889	►	330	8,347,715,889

Total Ontario balance:

	Line	Amount		Line	Amount
Total Ontario balance (amount from line 280 in Part 2, or amount from line 370 in Part 3 of Schedule 506 for the previous tax year)	340	8,348,179,915			
Add:					
Amount from eligible amalgamation*	350				
Amount from eligible post-2008 windup*	355				
Amount from eligible pre-2009 windup*	360				
Amount from specified pre-2009 transfers*	365				
Total Ontario balance at the end of the tax year		8,348,179,915	►	370	8,348,179,915
Transitional balance at the end of the tax year (line 330 **minus** line 370)				390	-464,026

If line 390 is positive, the corporation may be subject to a transitional tax debit. Complete Part 7 of this schedule.
If line 390 is negative, the corporation may be eligible to claim a transitional tax credit. Complete Part 8 of this schedule.

* See page 1 for definitions of eligible amalgamation, eligible post-2008 windup, eligible pre-2009 windup, and specified pre-2009 transfers. To calculate these amounts, you can use *Schedule 507, Ontario Transitional Tax Debits and Credits Calculation*.

Part 4 – Election to reduce federal SR&ED expenditure pool

The corporation may make this election if:

– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3).

Are you making an election under clause (b) of the definition of "I" in paragraph 1 of subsection 48(4) of the *Taxation Act, 2007* (Ontario)? **400** 1 Yes [ ] 2 No [X]

If you answered **no** to the question at line 400, go to Part 5. If you answered **yes** to the question at line 400, complete the following calculation:

Federal SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 124 in Part 1)				B
Deduct:				
Adjusted Ontario SR&ED incentive balance at the end of the previous tax year (amount from line 226 in Part 2)		1		
Ontario SR&ED expenditure pool closing balance at the end of the previous tax year (amount from line 224 in Part 2)		2		
Subtotal (amount 1 **plus** amount 2)		►		C
Subtotal (amount B **minus** amount C) (if negative, enter "0")				D
Federal balance before election (amount A from Part 1)				
Deduct:				
Total Ontario balance (amount from line 280 in Part 2)				
Subtotal (if negative, enter "0")				E

Enter the lesser of amount D and amount E on line 170 in Part 1.

Part 5 – Reference period and amortization period

Reference period

The reference period starts at the beginning of the corporation's first tax year ending after December 31, 2008, and ends on whichever date is earlier:

– five calendar years after the time immediately before the start of the corporation's reference period; or
– December 31, 2013.

Number of days in the corporation's reference period* (do not include February 29, 2008, and February 29, 2012) . . **410** 1,825

* The number of days in the corporation's reference period is 1825 unless:
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3). In this case, count the number of days from the beginning of the 2009 tax year to December 31, 2013; or
– the corporation was incorporated or amalgamated after January 1, 2009. In this case, count the number of days from the date of incorporation or date of amalgamation to December 31, 2013.

Amortization period

The amortization period starts at the beginning of the corporation's reference period and ends on whichever date is earlier:

– the end of the corporation's reference period; or
– the early termination date as indicated under line 430.

Number of days in the amortization period that are in the tax year** (do not include February 29, 2008, or February 29, 2012) **420** 365

** The number of days in the amortization period that are in the tax year is the number of days in the tax year unless:
– the tax year-end is later than the end of the reference period. In this case, count the number of days from the beginning of the tax year to the end of the reference period; or
– the corporation terminates the amortization period before the end of the tax year. In this case, count the number of days from the beginning of the tax year to the day of early termination.

Early termination of the amortization period

The amortization period of the corporation usually coincides with the corporation's reference period. However, if the corporation's amortization period ends in the tax year and before the reference period ends, tick the applicable box below to indicate the reason for the early termination.

430 The corporation:

1 ☐ – ceases to have a PE in Ontario in the tax year for any reason other than an eligible amalgamation or eligible post-2008 windup.

2 ☐ – becomes exempt from tax under Part I of the federal Act immediately after the end of the tax year.

3 ☐ – elects under subsection 47(2) of the *Taxation Act, 2007* (Ontario) to prepay the transitional tax debit.
Note: The Ontario Allocation Factor, calculated in Part 6, has to be at least 90% or the amount on line 390 in Part 3 is not more than $10,000.

4 ☐ – does not object to early termination of the amortization period and accelerated payment of the transitional tax credit, under subsection 46(3) of the *Taxation Act, 2007* (Ontario).
Note: Amount T in Part 8 cannot be more than $1,000.

If you ticked one of the above boxes:
– enter the date of the early termination, if the date is different from the tax year-end and you ticked box 1 at line 430 . . . . **435** ______
– enter the number of days from the first day of the tax year to the end of the corporation's reference period (do not include February 29, 2008, or February 29, 2012) . . . . **440** ______

Part 6 – Calculation of Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line F:

$$\frac{\text{Ontario taxable income*}}{\text{Taxable income**}} \quad \_\_\_\_\_\_ \quad = \quad \_\_\_\_\_\_$$

Ontario allocation factor (OAF) . . . . 1.00000 F

* Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If taxable income is nil, calculate the amount in column F as if taxable income were $1,000.

** Enter taxable income from line 360 or amount Z of the T2 return, whichever applies. If taxable income is nil, enter "1,000."

Part 7 – Transitional tax debits

Complete this part if the amount on line 390 in Part 3 is positive.

Amount from line 390 in Part 3					G
Amount G x Ontario basic rate of tax*	11.5 % =				H
Amount H x OAF (from line F in Part 6)	1.00000				I

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period from line 410 in Part 5 = 365 / 1,825 = 0.20000 J

Transitional tax debit before tax on elected reduced SR&ED pool (amount I **multiplied** by amount J)			K
Post-2008 SR&ED balance at the end of the year (amount HH from Part 12)	**460**		
Federal SR&ED transitional balance at the end of the year (amount QQ from Part 14)	**470**		
Tax on elected reduced SR&ED pool (the lesser of lines 460 and 470)			L
Total transitional tax debits (amount K **plus** amount L)			M

Enter amount M on line 276 of Schedule 5.

Part 8 – Transitional tax credits

Complete this part if the amount on line 390 in Part 3 is negative.

Amount C6 from Schedule 5		56,033,799	N
Deduct:			
Ontario resource tax credit (from line 404 of Schedule 5)			
Ontario tax credit for manufacturing and processing (from line 406 of Schedule 5)			
Ontario foreign tax credit (from line 408 of Schedule 5)			
Ontario credit union tax reduction (from line 410 of Schedule 5)			
Subtotal	►		O
Subtotal (amount N **minus** amount 0)		56,033,799	P

Number of days from line 420 in Part 5 / Number of days in the tax year (do not include February 29, 2008, or February 29, 2012) = 365 / 365 = 1.00000 Q

Ontario tax payable for purposes of the current year transitional tax credit (amount P **multiplied** by amount Q)	**510**	56,033,799	
Amount from line 390 in Part 3 (enter as a positive amount)		464,026	R
Amount R x Ontario basic rate of tax* 11.5 % =		53,363	S
Amount S x OAF (from line F in Part 6)		53,363	T

Number of days from line 440 (if applicable) or line 420 in Part 5 / Number of days in the corporation's reference period on line 410 in Part 5 = 365 / 1,825 = 0.20000 U

Current-year transitional tax credit (amount T **multiplied** by amount U)	**520**	10,673	
Ontario tax payable for purposes of the unused transitional tax credit carryforward (line 510 **minus** line 520) (if negative, enter "0")	**530**	56,023,126	

Transitional tax credit:

Lesser of amounts on line 510 and 520	10,673	V
Lesser of unused transitional tax credit available (amount Y from Part 9) and amount on line 530		W
Transitional tax credits (amount V **plus** amount W)	10,673	X

Enter amount X on line 414 of Schedule 5.

* Enter the rate calculated in Part 1 of Schedule 500, *Ontario Corporation Tax Calculation*.

Part 9 – Unused transitional tax credit

Unused transitional tax credit carryforward from previous year (amount from line 580 of the previous year)*			1	
Add:				
Unused transitional tax credit transferred from a predecessor corporation or a subsidiary on an eligible amalgamation or an eligible post-2008 windup*	560		2	
Unused transitional tax credit available (amount 1 **plus** amount 2)			▶	Y
Add:				
Current-year transitional tax credit (amount from line 520 in Part 8)			10,673	Z
Subtotal (amount Y **plus** amount Z)			10,673	3
Deduct:				
Transitional tax credit applied (amount X from Part 8)			10,673	AA
Unused transitional tax credit (available for later years) (amount 3 **minus** amount AA)		580		

* Enter "0" if this is the first tax year ending after 2008.

Complete parts 10 to 14 if the corporation or a predecessor made an election in Part 4 at the transition time.

Part 10 – Federal current SR&ED limit and federal current SR&ED deficit

Current SR&ED expenditures in the year under paragraph 37(1)(a)	610			
Capital SR&ED expenditures in the year under paragraph 37(1)(b)	614			
Repayment of assistance under paragraph 37(1)(c)	618			
Investment tax credit recaptured under subsections 127(27), (29), and (34) in the previous tax year	624			
Subtotal (total of lines 610 to 624)			▶	BB
Deduct:				
Assistance under paragraph 37(1)(d)	638			
Investment tax credits deducted under paragraph 37(1)(e)	644			
Subtotal (line 638 **plus** line 644)			▶	CC
Federal current SR&ED limit or federal current SR&ED deficit (amount BB **minus** amount CC)			650	

If the amount on line 650 is positive, enter it on line II In Part 13.

If the amount on line 650 is negative, enter it as a positive amount on line DD in Part 12.

Part 11 – Relevant OAF

Enter on line 660 whichever of the following amounts is greatest:

– the corporation's OAF for the tax year that includes its transition time (from line F in Part 6)	%	
– the greatest of the corporation's OAFs for a tax year ending in 2006, 2007, and 2008 as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario)	%	
– the greatest of the weighted OAFs* of the corporation and its designated corporations** for 2006, 2007, and 2008	%	
Relevant OAF	660	%

* The weighted OAF for two or more corporations for their tax years ending in 2006, 2007, or 2008 is the total of the following for each corporation:

– the corporation's OAF as determined under subsection 12(1) of the *Corporations Tax Act* (Ontario) for the tax year **multiplied** by the corporation's and its share of partnerships' qualified Ontario SR&ED expenditures in the tax year, **divided** by the total of all the corporations' and their shares of partnerships' qualified Ontario SR&ED expenditures in the tax year.

Qualified Ontario SR&ED expenditure is defined in section 11.2 of the *Corporations Tax Act* (Ontario).

** A designated corporation in respect of a particular corporation is:

1) a corporation that amalgamated with the particular corporation under section 87;

2) a corporation that wound up into the particular corporation under subsection 88(1); or

3) a designated corporation to a corporation identified in 1) or 2).

Part 12 – Post-2008 SR&ED balance

Federal current SR&ED deficit for the year (amount from line 650 in Part 10, if negative) (enter as a positive amount) . . . . DD

SR&ED expenditure amount deducted in the year under subsection 37(1) **670**

Deduct:

Cumulative post-2008 SR&ED limit at the end of the year (amount LL from Part 13) **675**

Subtotal (line 670 **minus** line 675) (if negative, enter "0") ► EE

Subtotal (amount DD **plus** amount EE) FF

Amount FF x 14 % GG

Post-2008 SR&ED balance at the end of the year (amount GG **multiplied** by line 660 from Part 11) . . . . HH

Enter amount HH on line 460 in Part 7.

Part 13 – Cumulative post-2008 SR&ED limit at the end of the year

Federal current SR&ED limit for the year (amount from line 650 in Part 10, if positive) II

Total of all federal SR&ED limits from previous tax years ending after December 31, 2008 . . . . **700**

Subtotal (line II **plus** line 700) JJ

Total of all amounts deducted under subsection 37(1) for previous tax years ending after December 31, 2008 . . . . **705**

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) **710**

Deduct:

Amounts included in line 710 that are reasonably attributable to the federal current SR&ED deficit for the year **715**

Subtotal (line 710 **minus** line 715) **720**

$$\frac{\text{Line 720}}{\text{Relevant OAF (from line 660 in Part 11) x 14 \%}} = \ldots\ldots \text{ KK}$$

Subtotal (line 705 **minus** amount KK) ► **730**

Cumulative post-2008 SR&ED limit at the end of the year (amount JJ **minus** line 730) (if negative, enter "0") LL

Enter amount LL on line 675 in Part 12.

Part 14 – Federal SR&ED transitional balance at the end of the year

Amount from line 170 in Part 1 (see Note) . . . . **735** MM

Relevant OAF (from line 660) (see Note) **multiplied** by amount MM . . . . NN

Amount NN x 14 % . . . . ► OO

Federal SR&ED transitional balance transferred on an eligible amalgamation or an eligible post-2008 wind-up **740**

Subtotal (amount OO **plus** line 740) PP

Deduct:

Total of all transitional tax debits on elected reduced SR&ED pool calculated under subsection 48(3) of the *Taxation Act, 2007* (Ontario) in the previous years (total of line L in Part 7 for previous years) **750**

Federal SR&ED transitional balance at the end of the year (amount PP **minus** line 750) . . . . QQ

Enter amount QQ on line 470 in Part 7.

Note: For tax years ending after 2009, enter the amount from line 170 and the relevant OAF from the 2009 tax year.

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SCHEDULE 508

ONTARIO RESEARCH AND DEVELOPMENT TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- Use this schedule to:
  - calculate an Ontario research and development tax credit (ORDTC);
  - claim an ORDTC earned in the tax year or carried forward from any of the 20 previous tax years that are a tax year ending after December 31, 2008, to reduce Ontario corporate income tax payable in the current tax year;
  - carry back an ORDTC to reduce Ontario corporate income tax payable in any of the three previous tax years, but not to a tax year that ends before January 1, 2009;
  - add an ORDTC that was allocated to the corporation by a partnership of which it was a member;
  - transfer an ORDTC after an amalgamation or windup; or
  - calculate a recapture of the ORDTC.
- The ORDTC is a 4.5% non-refundable tax credit on eligible expenditures incurred by a corporation in a tax year that ends after December 31, 2008.
- An eligible expenditure is an expenditure for a permanent establishment in Ontario of a corporation, that is a qualified expenditure for the purposes of section 127 of the federal *Income Tax Act* for scientific research and experimental development (SR&ED) carried on in Ontario.
- Only corporations that are not exempt from Ontario corporate income tax and none of whose income is exempt income can claim the ORDTC.
- Attach a completed copy of this schedule to the *T2 Corporation Income Tax Return.*

Part 1 – Ontario SR&ED expenditure pool

Total eligible expenditures incurred by the corporation in Ontario in the tax year	100	27,333,796	A		
Deduct: Government assistance, non-government assistance, or a contract payment for eligible expenditures	105	187,375	B		
Net eligible expenditures for the tax year (amount A **minus** amount B) (if negative, enter "0")		27,146,421	C		
Add: Eligible expenditures transferred to the corporation by another corporation	110		D		
Subtotal (amount C **plus** amount D)		27,146,421	▶	27,146,421	E
Deduct: Eligible expenditures the corporation transferred to another corporation	115				F
Ontario SR&ED expenditure pool (amount E **minus** amount F) (if negative, enter "0")	120			27,146,421	G

Part 2 – Calculation of the current part of the ORDTC

Ontario SR&ED expenditure pool (amount G in Part 1)		27,146,421	x	4.50 %	= 200	1,221,589	H
ORDTC allocated to a corporation by a partnership of which it is a member (other than a specified member) for a fiscal period that ends in the corporation's tax year *					205		I
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure other than for first term or second term shared-use equipment	210		x	4.50 %	= 215		J
Repayment made in the tax year of government or non-government assistance or a contract payment that reduced an eligible expenditure for first term or second term shared-use equipment	220	x 1 / 4 =	x	4.50 %	= 225		K
Current part of the ORDTC (total of amounts H to K)					230	1,221,589	L

* If there is a disposal or change of use of eligible property, see Part 6

Part 3 – Calculation of ORDTC available for deduction and ORDTC balance

ORDTC balance at the end of the previous tax year					M
Deduct: ORDTC expired after 20 tax years		300			N
ORDTC at the beginning of the tax year (amount M **minus** amount N)		305			O
Add:					
ORDTC transferred on amalgamation or windup		310			P
Current part of ORDTC (amount L in Part 2)	1,221,589 Q				

Are you waiving all or part of the current part of the ORDTC? 315 Yes 1 ☐ No 2 ☒

If you answered **yes** at line 315, enter the amount of the tax credit waived on line 320.

If you answered **no** at line 315, enter "0" on line 320.

Deduct: Waiver of the current part of the ORDTC	320	R			
Subtotal (amount Q **minus** amount R)	1,221,589	▶	1,221,589	S	
ORDTC available for deduction (total of amounts O, P and S)			1,221,589	▶	1,221,589 T
Deduct:					
ORDTC claimed * (Enter amount U on line 416 of Schedule 5, *Tax Calculation Supplementary – Corporations*)			1,221,589	U	
ORDTC carried back to a previous tax year (from Part 4)				V	
Subtotal (amount U **plus** amount V)			1,221,589	▶	1,221,589 W
ORDTC balance at the end of the tax year (amount T **minus** amount W)				325	X

* This amount cannot be more than the lesser of the following amounts:
– ORDTC available for deduction (amount T); or
– Ontario corporate income tax payable before the ORDTC and the Ontario corporate minimum tax credit (amount from line E6 of Schedule 5).

Part 4 – Request for carryback of tax credit

	Year Month Day			
1st previous tax year	2011-12-31	Credit to be applied	901	
2nd previous tax year	2010-12-31	Credit to be applied	902	
3rd previous tax year	2009-12-31	Credit to be applied	903	

Total (enter amount on line V in Part 3)

Part 5 – Analysis of tax credit available for carryforward by tax year of origin

You can complete this part to show all the credits from preceding tax years available for carryforward, by year of origin. This will help you determine the amount of credit that could expire in following years.

Tax year of origin (earliest tax year first) Year Month Day	Credit available		Tax year of origin (earliest tax year first) Year Month Day	Credit available
1993-03-31			2002-12-31	
1994-03-31			2003-12-31	
1995-03-31			2004-12-31	
1996-03-31			2005-12-31	
1997-03-31			2006-12-31	
1998-03-31			2007-12-31	
1999-03-31			2008-12-31	
1999-12-31			2009-12-31	
2000-12-31			2010-12-31	
2001-12-31			2011-12-31	
		Current tax year	2012-12-31	

Total (equals line 325 in Part 3) ____________

The amount available from the 20th preceding tax year will expire after this year. When you file your return for the next year, you will enter the expired amount on line 300 of Schedule 508 for that year.

Part 6 – Calculation of a recapture of ORDTC

You will have a recapture of ORDTC in a tax year when you meet **all** of the following conditions:

- you acquired a particular property in the current year or in any of the 20 previous tax years if the ORDTC was earned in a tax year ending after 2008;
- you claimed the cost of the property as an eligible expenditure for the ORDTC;
- the cost of the property was included in computing your ORDTC or was subject to an agreement made under subsection 127(13) of the federal Act to transfer qualified expenditures and section 42 of the *Taxation Act, 2007* (Ontario) applied; and
- you disposed of the property or converted it to commercial use in a tax year ending after December 31, 2008. You also meet this condition if you disposed of or converted to commercial use a property which 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 in Ontario. 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 federal investment tax credit (ITC) rate * of the original user in Calculation 1 below.

You have to report the recapture on Schedule 5 for the year in which you disposed of the property or converted it to commercial use. If the corporation is a member of a partnership, report its share of the recapture.

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.

* Federal ITC in calculations 1 and 2 should be determined without reference to paragraph (e) of the definition **investment tax credit** in subsection 127(9) of the federal Act.

Calculation 1 – If you meet all of the above conditions

	Y Amount of federal ITC you originally calculated for the property you acquired, or the original user's federal ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Z Amount calculated using the federal 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	AA Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter amount BB, on line KK in Part 7) ____________ BB

Calculation 2 – If the corporation is deemed by subsection 42(1) of the *Taxation Act, 2007* (Ontario) to have transferred all or part of the eligible expenditure to another corporation as a consequence of an agreement described in subsection 127(13) of the federal Act complete Calculation 2. Otherwise, enter nil on line II.

	CC The rate percentage that the transferee used to determine its federal ITC for a qualified expenditure that was transferred under an agreement under subsection 127(13) of the federal Act 720	DD The proceeds of disposition of the property if you dispose of it to a person at arm's length; or, in any other case, the fair market value of the property at conversion or disposition 730	EE The 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 for an agreement under subsection 127(13) of the federal Act) 740
1.			

	FF Amount determined by the formula (CC x DD) – EE (using the columns above)	GG The federal ITC earned by the transferee for the qualified expenditure that was transferred 750	HH Amount from column FF or GG, whichever is less
1.			

Subtotal (enter amount II on line LL below) ______ II

Calculation 3

As a member of a partnership, you will report your share of the ORDTC of the partnership after the ORDTC has been reduced by the amount of the recapture. If this is a positive amount, you will report it on line 205 in Part 2. However, if the partnership does not have enough ORDTC otherwise available to offset the recapture, then the amount by which reductions to the ORDTC exceeds additions (the excess) will be determined and reported on line JJ.

Corporate partner's share of the excess of ORDTC (enter amount JJ at line NN below) . . . . 760 ______ JJ

Part 7 – Total recapture of ORDTC

Recaptured federal ITC for Calculation 1 (amount from line BB) . . . . ______ KK

Recaptured federal ITC for Calculation 2 (amount from line II above) . . . . ______ LL

Amount KK **plus** amount LL . . . . ______ x 23.56 % = ______ MM

Add: Corporate partner's share of the excess of ORDTC for Calculation 3 (amount from line JJ above) . . . . ______ NN

Recapture of ORDTC (amount MM **plus** amount NN) (enter amount OO on line 277 of Schedule 5) . . . . ______ OO

Schedule A - Worksheet for eligible expenditures incurred by the corporation in Ontario for the current taxation year

This worksheet allows you to report the amount of eligible expenditures entered on Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim* which represents eligible expenditures as defined in section 127 of the *Income Tax Act* (ITA) with regard to scientific research and experimental development (SR&ED) **carried on in Ontario and attributable to a permanent establishment in Ontario of a corporation**.

Data on the worksheet is calculated based on the amounts on Form T661, but will have to be adjusted according to the rules of Ontario, if applicable, in particular when the corporation has had a permanent establishment in more than one jurisdiction. This data will be used when calculating Schedule 508 and Schedule 566.

Enter the breakdown between current and capital expenditures

		Current Expenditures			Capital Expenditures	
Total expenditures for SR&ED		29,695,522			400,975	
Add						
• payment of prior years' unpaid expenses (other than salary or wages)	+	781,577				
• prescribed proxy amount (Enter "0" if you use the traditional method)	+					
• expenditures on shared-use equipment				+		
• other additions	+			+		
Subtotal	=	30,477,099		=	400,975	
Less						
• current expenditures (other than salary or wages) not paid within 180 days of the tax year end	–	1,827,477				
• amounts paid in respect of an SR&ED contract to a person or partnership that is not taxable supplier	–					
• prescribed expenditures not allowed by regulations	–			–		
• other deductions	–	1,716,801		–		
• non-arm's length transactions						
– expenditures for non-arm's length SR&ED contracts	–					
– purchases (limited to costs) of goods and services from non-arm's length suppliers	–			–		
Subtotal	=	26,932,821	I	=	400,975	II
Total eligible expenditures incurred by the corporation in Ontario in the tax year (add amount I and II)				=	27,333,796	III

Enter amount III on line 100 of Schedule 508.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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
Selma Yam	(416) 345-6827

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 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 614,991,753

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$\ 400{,}000}{\$\ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Brock	Business Administration
2.	Brock	Business Administration
3.	Brock	Business Administration
4.	Brock	Business Administration
5.	Brock	Business Administration
6.	Brock	Business Administration
7.	Brock	Business Administration
8.	Brock	Business Administration
9.	Brock	Business Administration
10.	Brock	Masters of Business Economics
11.	Brock	Business Administration
12.	Brock	Business Administration
13.	Brock	Business Administration
14.	Brock	Business Administration
15.	Brock	Business Administration
16.	Brock	Business Administration
17.	Brock	Masters of Business Economics
18.	Brock	Masters of Business Economics
19.	Brock	Accounting
20.	Brock	Accounting
21.	Brock	Masters of Business Economics
22.	Brock	Masters of Business Economics
23.	Brock	Masters of Business Administration

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
24.	Brock	Masters of Business Administration
25.	Brock	Accounting
26.	Brock	Accounting
27.	Brock	Business Administration
28.	Brock	Masters of Business Economics
29.	Brock	Masters of Business Economics
30.	Brock	Business Economics
31.	Brock	Business Administration
32.	Brock	Business Administration
33.	Brock	Business Administration
34.	Brock	Mathematics
35.	Brock	Mathematics
36.	Brock	Computer Science
37.	Brock	Business Administration
38.	Brock	Business Administration
39.	Brock	Business Administration
40.	Brock	Business Administration
41.	Brock	Business Administration
42.	Brock	Business Administration
43.	Brock	Business Economics
44.	Brock	Business Economics
45.	Brock	Business Economics
46.	Brock	Masters of Business Economics
47.	Brock	Masters of Business Economics
48.	Brock	Business Administration
49.	Carleton	Engineering, Sustainable & Renewable Energy
50.	Carleton	Engineering, Sustainable & Renewable Energy
51.	Carleton	Engineering, Sustainable & Renewable Energy
52.	Carleton	Engineering, Sustainable & Renewable Energy
53.	Centennial College	Business Adminstration
54.	Fleming College	Security
55.	Georgian	Electrical Engineering Technology
56.	Georgian	Computer Studies
57.	Georgian	Business
58.	Georgian	Electrical Engineering Technology
59.	Georgian	Electrical Engineering Technology
60.	Georgian	Electrical Engineering Technology
61.	Georgian	Electrical Engineering Technology
62.	Georgian	Business Admin
63.	Georgian	Electrical Engineering Technology
64.	Georgian	Electrical Engineering Technology
65.	Georgian	Electrical Engineering Technology
66.	Georgian	Electrical Engineering Technology
67.	Georgian	Electrical Engineering Technology
68.	Georgian	Business Admin
69.	Georgian	Electrical Engineering Technology
70.	Georgian	Electrical Engineering Technology
71.	Georgian	Computer Studies
72.	Georgian	Electrical Engineering Technology
73.	Georgian	Human Resources
74.	Georgian	Electrical Engineering Technology
75.	Georgian	Electrical Engineering Technology
76.	Georgian	Electrical Engineering Technology
77.	Georgian	Business
78.	Georgian	Electrical Engineering Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
79.	Georgian	Electrical Engineering Technology
80.	Georgian	Electrical Engineering Technology
81.	Georgian	Electrical Engineering Technology
82.	Georgian	Electrical Engineering Technology
83.	Georgian	Computer IT
84.	Georgian	Electrical Engineering Technology
85.	Georgian	Electrical Engineering Technology
86.	Georgian	Business
87.	Georgian	Electrical Engineering Technology
88.	Georgian	Electrical Engineering Technology
89.	Georgian	Human Resources
90.	Georgian	Electrical Engineering Technology
91.	Georgian	Electrical Engineering Technology
92.	Georgian	Electrical Engineering
93.	Georgian	Electrical Engineering
94.	Georgian	Electrical Engineering Technology
95.	Georgian	Electrical Engineering Technology
96.	Georgian	Electrical Engineering
97.	Georgian	Electrical Engineering
98.	Georgian	Electrical Engineering Technology
99.	Georgian	Electrical Engineering Technology
100.	Georgian	Electrical Engineering Technology
101.	Georgian	Electrical Engineering Technology
102.	Georgian	Electrical Engineering Technology
103.	Georgian	Electrical Engineering Technology
104.	Georgian	Electrical Engineering Technology
105.	Georgian	Electrical Engineering Technology
106.	Georgian	Electrical Engineering Technology
107.	Georgian	Electrical Engineering Technology
108.	Georgian	Electrical Engineering Technology
109.	Georgian	Environmental Science
110.	Georgian	Environmental Science
111.	Georgian	Electrical Engineering Technology
112.	Georgian	Electrical Engineering Technology
113.	Georgian	Electrical Engineering Technology
114.	Georgian	Electrical Engineering Technician
115.	Georgian	Electrical Engineering Technology
116.	Georgian	Electrical Engineering Technology
117.	Georgian	Electrical Engineering Technology
118.	Georgian	Environmental Science
119.	Georgian	Electrical Engineering Technology
120.	Georgian	Electrical Engineering Technology
121.	Georgian	Electrical Engineering Technology
122.	Georgian	Electrical Engineering Technology
123.	Georgian	Electrical Engineering Technology
124.	Georgian	Electrical Engineering Technology
125.	Georgian	Electrical Engineering
126.	Georgian	Electrical Engineering
127.	Georgian	Electrical Engineering Technology
128.	Georgian	Business Admin
129.	Georgian	Electrical Engineering Technology
130.	Georgian	Electrical Engineering Technology
131.	Georgian	Electrical Engineering Technology
132.	Georgian	Marketing
133.	Georgian	Electrical Engineering Technology

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
134.	Georgian	Electrical Engineering
135.	Georgian	Electrical Engineering Technology
136.	Georgian	Electrical Engineering Technology
137.	Georgian	Electrical Engineering Technology
138.	Georgian	Electrical Engineering Technology
139.	Georgian	Electrical Engineering Technology
140.	Georgian	Electrical Engineering Technology
141.	Georgian	Electrical Engineering
142.	Georgian	Electrical Engineering Technology
143.	Georgian	Electrical Engineering Technology
144.	Georgian	Electrical Engineering Technology
145.	Georgian	Electrical Engineering Technology
146.	Georgian	Electrical Engineering Technology
147.	Georgian	Electrical Engineering Technology
148.	Guelph	Real Estate
149.	Guelph	Real Estate
150.	Guelph	Real Estate
151.	Guelph	Real Estate
152.	Guelph	Real Estate
153.	Guelph	Real Estate
154.	Guelph	Marketing Management
155.	Guelph	Marketing Management
156.	Guelph	Marketing Management
157.	Guelph	Environmental Science
158.	Guelph	Real Estate
159.	Guelph	Management Economics & Finance
160.	Guelph	Management Economics & Finance
161.	Guelph	Management Economics & Finance
162.	Guelph	Management Economics & Finance
163.	Guelph	Real Estate & Housing
164.	Guelph	Real Estate & Housing
165.	Guelph	Management Economics & Finance
166.	Guelph	Management Economics & Finance
167.	Guelph	Real Estate
168.	Guelph	Real Estate & Housing
169.	Lakehead	Computer IT
170.	Lakehead	Computer IT
171.	Lakehead	Computer IT
172.	Laurier	Business Administration
173.	Laurier	Business Administration
174.	Laurier	Business Administration
175.	McMaster	Electrical Engineer
176.	McMaster	Electrical Engineer
177.	McMaster	Electrical Engineer
178.	McMaster	Electrical Engineer
179.	McMaster	Electrical Engineer
180.	McMaster	Electrical Engineering
181.	McMaster	Electrical Engineering
182.	McMaster	Energy Engineer
183.	McMaster	Energy Engineer
184.	McMaster	Energy Engineer
185.	McMaster	Electrical Engineer
186.	McMaster	Electrical Engineering
187.	McMaster	Finance
188.	McMaster	Electrical Engineer

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
189.	McMaster	Electrical Engineer
190.	McMaster	Electrical Engineer
191.	McMaster	Electrical Engineer
192.	McMaster	Electrical Engineer
193.	McMaster	Electrical Engineer
194.	McMaster	Masters of Business Administration
195.	McMaster	Masters of Business Administration
196.	McMaster	Masters of Business Administration
197.	McMaster	Electrical Engineer
198.	McMaster	Electrical Engineering
199.	McMaster	Electrical Engineer
200.	McMaster	Electrical Engineer
201.	McMaster	Business Admin
202.	McMaster	Electrical Engineer
203.	McMaster	Electrical Engineer
204.	McMaster	Electrical Engineer
205.	McMaster	Electrical Engineer
206.	McMaster	Mathematics & Statistics
207.	McMaster	Mathematics & Statistics
208.	McMaster	Electrical Engineer
209.	McMaster	Electrical Engineer
210.	McMaster	Mathematics & Statistics
211.	McMaster	Mathematics & Statistics
212.	McMaster	Electrical Engineer
213.	McMaster	Electrical Engineer
214.	McMaster	Electrical Engineering
215.	McMaster	Electrical Engineering
216.	McMaster	Electrical Engineering Technology
217.	McMaster	Electrical Engineering Technology
218.	McMaster	Electrical Engineering
219.	McMaster	Electrical Engineering
220.	McMaster	Electrical Engineer
221.	McMaster	Computer Engineer
222.	McMaster	Computer Engineer
223.	McMaster	Electrical Engineer
224.	McMaster	Electrical Engineer
225.	McMaster	Electrical Engineer
226.	McMaster	Electrical Engineer
227.	McMaster	Electrical Engineer
228.	McMaster	Electrical Engineer
229.	McMaster	Electrical Engineer
230.	McMaster	Electrical Engineer
231.	Mohawk	Electrical Engineering Technology
232.	Mohawk	Electrical Engineering Technology
233.	Mohawk	Electrical Engineering Technology
234.	Mohawk	Electrical Engineering Technology
235.	Mohawk	Electrical Engineering Technology
236.	Mohawk	Electrical Engineering Technology
237.	Mohawk	Electrical Engineering Technology
238.	Mohawk	Electrical Engineering Technology
239.	Mohawk	Electrical Engineering Technology
240.	Mohawk	Electrical Engineering Technology
241.	Mohawk	Electrical Engineering Technology
242.	Mohawk	Electrical Engineering Technology
243.	Mohawk	Electrical Engineering Technician

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
244.	Mohawk	Electrical Engineering Technician
245.	Mohawk	Electrical Engineering Technology
246.	Mohawk	Electrical Engineering Technology
247.	Mohawk	Electrical Engineering Technology
248.	Mohawk	Electrical Engineering Technology
249.	Mohawk	Electrical Engineering Technology
250.	Mohawk	Electrical Engineering Technician
251.	Mohawk	Electrical Engineering Technology
252.	Mohawk	Electrical Engineering Technology
253.	Mohawk	Electrical Engineering Technician
254.	Mohawk	Electrical Engineering Technology
255.	Mohawk	Electrical Engineering Technician
256.	Mohawk	Electrical Engineering Technician
257.	Mohawk	Electrical Engineering Technology
258.	Mohawk	Electrical Engineering Technology
259.	Mohawk	Electrical Engineering Technology
260.	Mohawk	Electrical Engineering Technology
261.	Mohawk	Electrical Engineering Technology
262.	Mohawk	Electrical Engineering Technology
263.	Mohawk	Electrical Engineering Technology
264.	Mohawk	Electrical Engineering Technician
265.	Mohawk	Electrical Engineering Technology
266.	Mohawk	Electrical Engineering Technology
267.	Mohawk	Electrical Engineering Technology
268.	Mohawk	Electrical Engineering Technology
269.	Mohawk	Electrical Engineering Technology
270.	Mohawk	Electrical Engineering Technology
271.	Mohawk	Electrical Engineering Technology
272.	Mohawk	Electrical Engineering Technology
273.	Mohawk	Electrical Engineering Technology
274.	Mohawk	Electrical Engineering Technology
275.	Mohawk	Electrical Engineering Technology
276.	Mohawk	Electrical Engineering Technology
277.	Mohawk	Electrical Engineering Technology
278.	Mohawk	Electrical Engineering Technology
279.	Mohawk	Electrical Engineering Technology
280.	Mohawk	Electrical Engineering Technology
281.	Mohawk	Electrical Engineering Technology
282.	Mohawk	Electrical Engineering Technology
283.	Mohawk	Electrical Engineering Technology
284.	Mohawk	Electrical Engineering Technology
285.	Ryerson	Civil Engineer
286.	Ryerson	Civil Engineer
287.	Ryerson	Civil Engineer
288.	Ryerson	Occupational Health and Safety
289.	Ryerson	Occupational Health and Safety
290.	Ryerson	Electrical Engineer
291.	Sheridan	Environmental Science
292.	Toronto	Engineering Science
293.	Toronto	Civil Engineer
294.	Toronto	Engineer
295.	Toronto	Civil Engineer
296.	Toronto	Electrical Engineer
297.	Toronto	Electrical Engineer
298.	Toronto	Engineer

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
299.	Toronto	Electrical Engineer
300.	Toronto	Electrical Engineer
301.	Toronto	Computer Engineer
302.	Toronto	Civil Engineer
303.	Toronto	Engineering Science
304.	Toronto	Math
305.	Toronto	Electrical Engineer
306.	Toronto	Engineer
307.	Toronto - Scarborough	Finance
308.	Toronto - Scarborough	Finance/Accounting
309.	Toronto - Scarborough	Finance/Accounting
310.	Toronto - Scarborough	Finance
311.	Toronto - Scarborough	Finance
312.	Toronto - Scarborough	Finance/Accounting
313.	Toronto - Scarborough	Finance/Accounting
314.	Toronto - Scarborough	Business
315.	Toronto - Scarborough	Business
316.	Toronto - Scarborough	Business
317.	Toronto - Scarborough	Finance
318.	Toronto - Scarborough	Finance
319.	Toronto - Scarborough	Finance
320.	Toronto - Scarborough	Finance
321.	Toronto - Scarborough	Finance
322.	Toronto - Scarborough	Finance/Accounting
323.	Toronto - Scarborough	Finance/Accounting
324.	Toronto - Scarborough	Finance
325.	UOIT	Electrical Engineer
326.	UOIT	Electrical Engineer
327.	UOIT	Electrical Engineer
328.	UOIT	Electrical Engineer
329.	UOIT	Electrical Engineer
330.	UOIT	Electrical Engineer
331.	UOIT	Electrical Engineer
332.	UOIT	Electrical Engineer
333.	UOIT	Electrical Engineer
334.	UOIT	Electrical Engineer
335.	UOIT	Electrical Engineer
336.	UOIT	Electrical Engineer
337.	UOIT	Electrical Engineer
338.	UOIT	Electrical Engineer
339.	Waterloo	Electrical Engineer
340.	Waterloo	Electrical Engineer
341.	Waterloo	Economics
342.	Waterloo	Physics
343.	Waterloo	Actuarial Science
344.	Waterloo	Business Administration
345.	Waterloo	Environmental Engineering
346.	Waterloo	Electrical Engineer
347.	Waterloo	Math & Stats
348.	Waterloo	Electrical Engineer
349.	Waterloo	Electrical Engineering
350.	Waterloo	Electrical Engineer
351.	Waterloo	Electrical Engineer
352.	Waterloo	Electrical Engineer
353.	Western	Engineer

	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
354.	Western	Electrical Engineer
355.	Western	Electrical Engineer
356.	Western	Electrical Engineer
357.	Windsor	Electrical Engineer
358.	Windsor	Electrical Engineer
359.	Windsor	Electrical Engineer
360.	Windsor	Electrical Engineer
361.	Windsor	Civil Engineer
362.	Windsor	Electrical Engineer
363.	Windsor	Computer Science Applied Computing
364.	Windsor	Computer Science Applied Computing
365.	Windsor	Computer Science Applied Computing
366.	Windsor	Business Administration
367.	Windsor	Electrical Engineer
368.	Windsor	Electrical Engineer
369.	Windsor	Electrical Engineer
370.	York	Information Technology
371.	York	Finance
372.	York	Computer Science

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
1.	Co-op 1	2012-08-16	2012-12-31
2.	Co-op 2	2012-01-01	2012-04-30
3.	Co-op 3	2012-05-01	2012-08-31
4.	Co-op 4	2012-09-04	2012-12-31
5.	Co-op 5	2012-01-05	2012-04-30
6.	Co-op 6	2012-05-01	2012-08-31
7.	Co-op 7	2012-09-01	2012-12-31
8.	Co-op 8	2012-05-28	2012-08-31
9.	Co-op 9	2012-09-01	2012-12-29
10.	Co-op 10	2012-01-01	2012-05-01
11.	Co-op 11	2012-01-01	2012-04-28
12.	Co-op 12	2012-01-01	2012-04-30
13.	Co-op 13	2012-05-01	2012-08-31
14.	Co-op 14	2012-09-01	2012-12-31
15.	Co-op 15	2012-01-05	2012-04-30
16.	Co-op 16	2012-05-01	2012-08-23
17.	Co-op 17	2012-01-01	2012-04-30
18.	Co-op 18	2012-05-01	2012-08-31
19.	Co-op 19	2012-01-01	2012-04-30
20.	Co-op 20	2012-05-01	2012-09-01
21.	Co-op 21	2012-04-23	2012-08-31
22.	Co-op 22	2012-09-01	2012-12-21
23.	Co-op 23	2012-05-03	2012-08-31
24.	Co-op 24	2012-08-31	2012-12-31
25.	Co-op 25	2012-01-01	2012-04-30
26.	Co-op 26	2012-05-01	2012-08-31
27.	Co-op 27	2012-04-26	2012-09-06
28.	Co-op 28	2012-05-03	2012-08-31
29.	Co-op 29	2012-09-01	2012-12-31

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
30.	Co-op 30	2012-01-01	2012-04-30
31.	Co-op 31	2012-01-01	2012-04-26
32.	Co-op 32	2012-04-26	2012-08-31
33.	Co-op 33	2012-09-01	2012-12-29
34.	Co-op 34	2012-04-26	2012-08-31
35.	Co-op 35	2012-09-01	2012-12-31
36.	Co-op 36	2012-04-30	2012-09-01
37.	Co-op 37	2012-05-03	2012-08-31
38.	Co-op 38	2012-09-01	2012-12-31
39.	Co-op 39	2012-01-01	2012-04-30
40.	Co-op 40	2012-05-01	2012-09-01
41.	Co-op 41	2012-05-03	2012-08-31
42.	Co-op 42	2012-09-01	2012-12-31
43.	Co-op 43	2012-01-12	2012-04-30
44.	Co-op 44	2012-05-01	2012-08-31
45.	Co-op 45	2012-09-01	2012-12-31
46.	Co-op 46	2012-05-03	2012-08-31
47.	Co-op 47	2012-09-01	2012-12-31
48.	Co-op 48	2012-01-03	2012-04-30
49.	Co-op 49	2012-01-01	2012-04-30
50.	Co-op 50	2012-05-01	2012-08-31
51.	Co-op 51	2012-01-01	2012-04-30
52.	Co-op 52	2012-05-01	2012-09-01
53.	Co-op 53	2012-01-01	2012-04-28
54.	Co-op 54	2012-01-01	2012-04-30
55.	Co-op 55	2012-04-30	2012-08-31
56.	Co-op 56	2012-05-14	2012-09-01
57.	Co-op 57	2012-04-23	2012-09-08
58.	Co-op 58	2012-09-10	2012-12-22
59.	Co-op 59	2012-09-10	2012-12-21
60.	Co-op 60	2012-09-10	2012-12-31
61.	Co-op 61	2012-01-03	2012-04-28
62.	Co-op 62	2012-01-01	2012-05-05
63.	Co-op 63	2012-04-30	2012-09-01
64.	Co-op 64	2012-01-03	2012-04-30
65.	Co-op 65	2012-08-27	2012-12-31
66.	Co-op 66	2012-04-30	2012-08-31
67.	Co-op 67	2012-04-30	2012-08-31
68.	Co-op 68	2012-04-20	2012-08-31
69.	Co-op 69	2012-01-03	2012-04-28
70.	Co-op 70	2012-04-30	2012-09-01
71.	Co-op 71	2012-01-09	2012-04-28
72.	Co-op 72	2012-01-01	2012-05-05
73.	Co-op 73	2012-08-20	2012-12-31
74.	Co-op 74	2012-01-01	2012-04-30
75.	Co-op 75	2012-09-04	2012-12-29
76.	Co-op 76	2012-01-03	2012-04-28
77.	Co-op 77	2012-01-03	2012-04-27
78.	Co-op 78	2012-01-03	2012-04-30
79.	Co-op 79	2012-09-04	2012-12-22
80.	Co-op 80	2012-01-03	2012-04-28
81.	Co-op 81	2012-01-03	2012-04-27
82.	Co-op 82	2012-09-10	2012-12-22
83.	Co-op 83	2012-01-09	2012-04-28

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
84.	Co-op 84	2012-05-01	2012-08-31
85.	Co-op 85	2012-04-30	2012-08-31
86.	Co-op 86	2012-04-30	2012-09-01
87.	Co-op 87	2012-01-03	2012-04-27
88.	Co-op 88	2012-09-10	2012-12-22
89.	Co-op 89	2012-08-27	2012-12-31
90.	Co-op 90	2012-01-16	2012-04-27
91.	Co-op 91	2012-08-20	2012-12-31
92.	Co-op 92	2012-01-03	2012-04-27
93.	Co-op 93	2012-09-10	2012-12-22
94.	Co-op 94	2012-08-30	2012-12-31
95.	Co-op 95	2012-08-27	2012-12-31
96.	Co-op 96	2012-01-03	2012-04-27
97.	Co-op 97	2012-09-10	2012-12-22
98.	Co-op 98	2012-01-03	2012-04-28
99.	Co-op 99	2012-01-03	2012-04-28
100.	Co-op 100	2012-01-03	2012-04-28
101.	Co-op 101	2012-09-04	2012-12-31
102.	Co-op 102	2012-09-10	2012-12-22
103.	Co-op 103	2012-09-04	2012-12-22
104.	Co-op 104	2012-09-10	2012-12-22
105.	Co-op 105	2012-04-30	2012-08-31
106.	Co-op 106	2012-04-30	2012-09-01
107.	Co-op 107	2012-01-03	2012-04-27
108.	Co-op 108	2012-09-10	2012-12-31
109.	Co-op 109	2012-05-03	2012-08-31
110.	Co-op 110	2012-09-01	2012-12-29
111.	Co-op 111	2012-04-30	2012-08-31
112.	Co-op 112	2012-04-30	2012-09-01
113.	Co-op 113	2012-01-03	2012-04-28
114.	Co-op 114	2012-09-10	2012-12-22
115.	Co-op 115	2012-01-03	2012-04-28
116.	Co-op 116	2012-01-03	2012-04-27
117.	Co-op 117	2012-08-20	2012-12-31
118.	Co-op 118	2012-05-03	2012-08-23
119.	Co-op 119	2012-08-16	2012-12-15
120.	Co-op 120	2012-04-30	2012-08-31
121.	Co-op 121	2012-01-03	2012-04-28
122.	Co-op 122	2012-01-01	2012-05-03
123.	Co-op 123	2012-01-03	2012-04-28
124.	Co-op 124	2012-04-30	2012-09-01
125.	Co-op 125	2012-01-03	2012-04-27
126.	Co-op 126	2012-09-10	2012-12-22
127.	Co-op 127	2012-01-03	2012-04-28
128.	Co-op 128	2012-01-01	2012-05-05
129.	Co-op 129	2012-01-03	2012-04-28
130.	Co-op 130	2012-04-30	2012-09-01
131.	Co-op 131	2012-04-30	2012-08-31
132.	Co-op 132	2012-08-20	2012-12-31
133.	Co-op 133	2012-01-03	2012-04-28
134.	Co-op 134	2012-09-10	2012-12-21
135.	Co-op 135	2012-01-03	2012-04-28
136.	Co-op 136	2012-01-09	2012-04-27
137.	Co-op 137	2012-09-04	2012-12-22

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
138.	Co-op 138	2012-09-10	2012-12-22
139.	Co-op 139	2012-09-04	2012-12-29
140.	Co-op 140	2012-01-03	2012-05-05
141.	Co-op 141	2012-09-10	2012-12-22
142.	Co-op 142	2012-04-30	2012-09-01
143.	Co-op 143	2012-01-03	2012-04-28
144.	Co-op 144	2012-01-03	2012-04-28
145.	Co-op 145	2012-01-03	2012-04-28
146.	Co-op 146	2012-01-03	2012-04-28
147.	Co-op 147	2012-01-03	2012-04-28
148.	Co-op 148	2012-01-06	2012-04-30
149.	Co-op 149	2012-05-01	2012-08-18
150.	Co-op 150	2012-05-07	2012-09-01
151.	Co-op 151	2012-05-07	2012-08-31
152.	Co-op 152	2012-05-22	2012-09-01
153.	Co-op 153	2012-01-09	2012-05-05
154.	Co-op 154	2012-01-23	2012-04-30
155.	Co-op 155	2012-05-01	2012-08-31
156.	Co-op 156	2012-09-01	2012-12-29
157.	Co-op 157	2012-09-04	2012-12-29
158.	Co-op 158	2012-09-05	2012-12-22
159.	Co-op 159	2012-04-26	2012-08-31
160.	Co-op 160	2012-09-01	2012-12-22
161.	Co-op 161	2012-06-04	2012-08-31
162.	Co-op 162	2012-09-01	2012-12-22
163.	Co-op 163	2012-05-02	2012-08-31
164.	Co-op 164	2012-09-01	2012-12-31
165.	Co-op 165	2012-01-03	2012-04-30
166.	Co-op 166	2012-05-01	2012-09-01
167.	Co-op 167	2012-09-06	2012-12-20
168.	Co-op 168	2012-09-10	2012-12-22
169.	Co-op 169	2012-01-03	2012-04-30
170.	Co-op 170	2012-05-01	2012-08-31
171.	Co-op 171	2012-09-01	2012-12-31
172.	Co-op 172	2012-01-03	2012-04-28
173.	Co-op 173	2012-04-30	2012-08-31
174.	Co-op 174	2012-09-01	2012-12-18
175.	Co-op 175	2012-01-01	2012-04-30
176.	Co-op 176	2012-05-01	2012-09-08
177.	Co-op 177	2012-01-01	2012-04-30
178.	Co-op 178	2012-05-01	2012-08-31
179.	Co-op 179	2012-09-01	2012-12-20
180.	Co-op 180	2012-01-01	2012-04-30
181.	Co-op 181	2012-05-01	2012-08-30
182.	Co-op 182	2012-01-01	2012-04-30
183.	Co-op 183	2012-05-01	2012-08-31
184.	Co-op 184	2012-09-01	2012-12-22
185.	Co-op 185	2012-01-01	2012-04-28
186.	Co-op 186	2012-01-01	2012-04-28
187.	Co-op 187	2011-08-24	2012-09-01
188.	Co-op 188	2012-01-01	2012-04-30
189.	Co-op 189	2012-05-01	2012-08-31
190.	Co-op 190	2012-09-01	2012-12-22
191.	Co-op 191	2012-01-01	2012-04-28

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
192.	Co-op 192	2012-01-01	2012-04-30
193.	Co-op 193	2012-05-01	2012-08-30
194.	Co-op 194	2012-01-05	2012-04-30
195.	Co-op 195	2012-05-01	2012-08-31
196.	Co-op 196	2012-09-01	2012-12-15
197.	Co-op 197	2012-01-01	2012-04-28
198.	Co-op 198	2012-01-01	2012-04-28
199.	Co-op 199	2012-01-01	2012-04-30
200.	Co-op 200	2012-05-01	2012-09-07
201.	Co-op 201	2012-01-05	2012-04-18
202.	Co-op 202	2012-01-01	2012-04-30
203.	Co-op 203	2012-05-01	2012-09-08
204.	Co-op 204	2012-01-01	2012-04-30
205.	Co-op 205	2012-05-01	2012-09-01
206.	Co-op 206	2012-01-09	2012-04-30
207.	Co-op 207	2012-05-01	2012-09-06
208.	Co-op 208	2012-01-01	2012-04-30
209.	Co-op 209	2012-05-01	2012-09-01
210.	Co-op 210	2012-01-09	2012-04-30
211.	Co-op 211	2012-05-01	2012-09-01
212.	Co-op 212	2012-01-01	2012-04-30
213.	Co-op 213	2012-05-01	2012-09-01
214.	Co-op 214	2012-01-01	2012-04-30
215.	Co-op 215	2012-05-01	2012-09-01
216.	Co-op 216	2012-01-01	2012-04-30
217.	Co-op 217	2012-05-01	2012-08-30
218.	Co-op 218	2012-01-01	2012-04-30
219.	Co-op 219	2012-05-01	2012-08-25
220.	Co-op 220	2012-09-04	2012-12-31
221.	Co-op 221	2012-05-03	2012-08-31
222.	Co-op 222	2012-09-01	2012-12-31
223.	Co-op 223	2012-05-02	2012-08-31
224.	Co-op 224	2012-09-01	2012-12-31
225.	Co-op 225	2012-05-07	2012-08-31
226.	Co-op 226	2012-09-01	2012-12-31
227.	Co-op 227	2012-04-30	2012-08-31
228.	Co-op 228	2012-09-01	2012-12-31
229.	Co-op 229	2012-01-01	2012-04-30
230.	Co-op 230	2012-05-01	2012-08-18
231.	Co-op 231	2012-04-19	2012-08-31
232.	Co-op 232	2012-09-01	2012-12-31
233.	Co-op 233	2012-01-01	2012-04-30
234.	Co-op 234	2012-05-01	2012-09-01
235.	Co-op 235	2012-04-30	2012-08-31
236.	Co-op 236	2012-01-01	2012-04-30
237.	Co-op 237	2012-05-01	2012-08-31
238.	Co-op 238	2012-09-01	2012-12-20
239.	Co-op 239	2012-01-01	2012-05-05
240.	Co-op 240	2012-01-09	2012-04-30
241.	Co-op 241	2012-05-01	2012-08-31
242.	Co-op 242	2012-09-01	2012-12-15
243.	Co-op 243	2012-04-30	2012-08-31
244.	Co-op 244	2012-09-01	2012-12-22
245.	Co-op 245	2012-04-30	2012-09-01

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
246.	Co-op 246	2012-01-03	2012-04-30
247.	Co-op 247	2012-05-01	2012-08-31
248.	Co-op 248	2012-09-01	2012-12-22
249.	Co-op 249	2012-01-03	2012-04-27
250.	Co-op 250	2012-04-30	2012-08-31
251.	Co-op 251	2012-05-01	2012-09-01
252.	Co-op 252	2012-04-30	2012-08-31
253.	Co-op 253	2012-05-07	2012-09-07
254.	Co-op 254	2012-01-03	2012-04-27
255.	Co-op 255	2012-01-03	2012-04-30
256.	Co-op 256	2012-05-01	2012-08-29
257.	Co-op 257	2012-01-03	2012-04-30
258.	Co-op 258	2012-05-01	2012-08-31
259.	Co-op 259	2012-05-01	2012-08-31
260.	Co-op 260	2012-09-01	2012-12-22
261.	Co-op 261	2012-01-03	2012-04-28
262.	Co-op 262	2012-01-01	2012-04-30
263.	Co-op 263	2012-05-01	2012-09-01
264.	Co-op 264	2012-01-03	2012-04-28
265.	Co-op 265	2012-01-03	2012-04-28
266.	Co-op 266	2012-01-03	2012-04-28
267.	Co-op 267	2012-01-03	2012-04-30
268.	Co-op 268	2012-05-01	2012-08-31
269.	Co-op 269	2012-09-01	2012-12-22
270.	Co-op 270	2012-05-07	2012-08-31
271.	Co-op 271	2012-09-01	2012-12-22
272.	Co-op 272	2012-01-01	2012-04-30
273.	Co-op 273	2012-05-01	2012-08-31
274.	Co-op 274	2012-09-01	2012-12-31
275.	Co-op 275	2012-04-30	2012-08-31
276.	Co-op 276	2012-09-01	2012-12-22
277.	Co-op 277	2012-09-05	2012-12-22
278.	Co-op 278	2012-01-09	2012-05-11
279.	Co-op 279	2012-01-03	2012-04-28
280.	Co-op 280	2012-01-03	2012-04-27
281.	Co-op 281	2012-09-05	2012-12-22
282.	Co-op 282	2012-01-03	2012-04-28
283.	Co-op 283	2012-01-03	2012-04-30
284.	Co-op 284	2012-05-01	2012-09-01
285.	Co-op 285	2011-08-29	2012-09-01
286.	Co-op 286	2011-09-08	2012-09-06
287.	Co-op 287	2011-08-22	2012-08-31
288.	Co-op 288	2012-05-07	2012-08-31
289.	Co-op 289	2012-09-01	2012-12-19
290.	Co-op 290	2011-09-06	2012-04-28
291.	Co-op 291	2012-09-04	2012-12-29
292.	Co-op 292	2011-09-08	2012-09-06
293.	Co-op 293	2011-09-01	2012-09-01
294.	Co-op 294	2011-05-02	2012-09-01
295.	Co-op 295	2011-08-29	2012-09-01
296.	Co-op 296	2011-09-08	2012-09-01
297.	Co-op 297	2011-09-12	2012-09-08
298.	Co-op 298	2011-09-12	2012-09-01
299.	Co-op 299	2011-09-08	2012-09-01

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
300.	Co-op 300	2011-09-12	2012-09-01
301.	Co-op 301	2011-09-12	2012-09-15
302.	Co-op 302	2011-08-29	2012-09-01
303.	Co-op 303	2011-09-22	2012-09-01
304.	Co-op 304	2011-09-01	2012-04-26
305.	Co-op 305	2011-09-08	2012-09-01
306.	Co-op 306	2012-05-07	2012-08-30
307.	Co-op 307	2012-09-05	2012-12-22
308.	Co-op 308	2012-05-07	2012-08-31
309.	Co-op 309	2012-09-01	2012-12-20
310.	Co-op 310	2012-01-01	2012-04-28
311.	Co-op 311	2012-08-13	2012-12-31
312.	Co-op 312	2012-04-26	2012-08-31
313.	Co-op 313	2012-09-01	2012-12-28
314.	Co-op 314	2012-01-12	2012-04-30
315.	Co-op 315	2012-05-01	2012-08-31
316.	Co-op 316	2012-09-01	2012-12-29
317.	Co-op 317	2012-01-05	2012-04-30
318.	Co-op 318	2012-05-01	2012-08-31
319.	Co-op 319	2012-09-01	2012-12-29
320.	Co-op 320	2012-01-12	2012-04-30
321.	Co-op 321	2012-05-01	2012-08-31
322.	Co-op 322	2012-05-03	2012-08-31
323.	Co-op 323	2012-09-01	2012-12-31
324.	Co-op 324	2012-08-13	2012-12-31
325.	Co-op 325	2011-09-01	2012-04-28
326.	Co-op 326	2012-01-03	2012-12-29
327.	Co-op 327	2012-04-26	2012-09-01
328.	Co-op 328	2012-01-03	2012-12-28
329.	Co-op 329	2012-01-10	2012-04-30
330.	Co-op 330	2012-05-01	2012-09-08
331.	Co-op 331	2012-01-03	2012-04-30
332.	Co-op 332	2012-05-01	2012-08-31
333.	Co-op 333	2012-01-03	2012-12-29
334.	Co-op 334	2012-01-12	2012-12-29
335.	Co-op 335	2012-01-19	2012-04-30
336.	Co-op 336	2012-05-01	2012-08-23
337.	Co-op 337	2012-01-03	2012-04-30
338.	Co-op 338	2012-05-01	2012-08-31
339.	Co-op 339	2012-09-04	2012-12-22
340.	Co-op 340	2012-09-06	2012-12-22
341.	Co-op 341	2012-01-03	2012-04-28
342.	Co-op 342	2012-01-03	2012-04-28
343.	Co-op 343	2012-09-24	2012-12-31
344.	Co-op 344	2012-05-03	2012-08-29
345.	Co-op 345	2012-01-09	2012-04-28
346.	Co-op 346	2012-01-09	2012-04-28
347.	Co-op 347	2012-05-03	2012-09-01
348.	Co-op 348	2012-08-27	2012-12-22
349.	Co-op 349	2012-01-03	2012-04-28
350.	Co-op 350	2012-01-01	2012-04-30
351.	Co-op 351	2012-09-04	2012-12-22
352.	Co-op 352	2012-01-03	2012-04-28
353.	Co-op 353	2012-04-30	2012-09-01

	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
354.	Co-op 354	2012-04-30	2012-08-31
355.	Co-op 355	2012-05-03	2012-08-31
356.	Co-op 356	2012-05-07	2012-08-31
357.	Co-op 357	2012-01-05	2012-04-30
358.	Co-op 358	2012-05-01	2012-08-31
359.	Co-op 359	2012-09-01	2012-12-27
360.	Co-op 360	2012-01-05	2012-04-28
361.	Co-op 361	2012-09-04	2012-12-29
362.	Co-op 362	2012-09-04	2012-12-31
363.	Co-op 363	2012-01-01	2012-04-30
364.	Co-op 364	2012-05-01	2012-08-31
365.	Co-op 365	2012-09-01	2012-12-29
366.	Co-op 366	2012-09-17	2012-12-31
367.	Co-op 367	2012-01-09	2012-04-30
368.	Co-op 368	2012-05-01	2012-08-31
369.	Co-op 369	2012-09-01	2012-12-31
370.	Co-op 370	2011-09-12	2012-12-31
371.	Co-op 371	2011-08-22	2012-08-23
372.	Co-op 372	2011-08-11	2012-04-28

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

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.		10.000 %	16,286	25.000 %		19
2.		10.000 %	16,252	25.000 %		17
3.		10.000 %	16,252	25.000 %		17
4.		10.000 %	13,875	25.000 %		16
5.		10.000 %	18,209	25.000 %		16
6.		10.000 %	18,209	25.000 %		17
7.		10.000 %	18,209	25.000 %		17
8.		10.000 %	13,775	25.000 %		14
9.		10.000 %	13,775	25.000 %		17
10.		10.000 %	24,622	25.000 %		17
11.		10.000 %	17,419	25.000 %		17
12.		10.000 %	21,587	25.000 %		17
13.		10.000 %	21,587	25.000 %		17
14.		10.000 %	21,587	25.000 %		17
15.		10.000 %	20,397	25.000 %		16
16.		10.000 %	20,397	25.000 %		15
17.		10.000 %	20,581	25.000 %		17
18.		10.000 %	20,581	25.000 %		17
19.		10.000 %	19,075	25.000 %		17
20.		10.000 %	19,075	25.000 %		17
21.		10.000 %	19,861	25.000 %		19
22.		10.000 %	19,861	25.000 %		16
23.		10.000 %	18,644	25.000 %		17
24.		10.000 %	18,644	25.000 %		17
25.		10.000 %	19,652	25.000 %		17
26.		10.000 %	19,652	25.000 %		17
27.		10.000 %	21,219	25.000 %		18
28.		10.000 %	18,838	25.000 %		17
29.		10.000 %	18,838	25.000 %		17
30.		10.000 %	21,466	25.000 %		17
31.		10.000 %	20,507	25.000 %		16
32.		10.000 %	18,336	25.000 %		18
33.		10.000 %	18,336	25.000 %		17
34.		10.000 %	18,336	25.000 %		18
35.		10.000 %	18,336	25.000 %		17
36.		10.000 %	20,527	25.000 %		18
37.		10.000 %	17,551	25.000 %		17
38.		10.000 %	17,551	25.000 %		17
39.		10.000 %	18,979	25.000 %		17
40.		10.000 %	18,979	25.000 %		17
41.		10.000 %	19,017	25.000 %		17
42.		10.000 %	19,017	25.000 %		17
43.		10.000 %	18,828	25.000 %		15
44.		10.000 %	18,828	25.000 %		17
45.		10.000 %	18,828	25.000 %		17
46.		10.000 %	18,838	25.000 %		17
47.		10.000 %	18,838	25.000 %		17
48.		10.000 %	21,229	25.000 %		16
49.		10.000 %	21,141	25.000 %		17
50.		10.000 %	21,141	25.000 %		17
51.		10.000 %	21,450	25.000 %		17

	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)
52.		10.000 %	21,450	25.000 %		17
53.		10.000 %	18,171	25.000 %		17
54.		10.000 %	26,493	25.000 %		17
55.		10.000 %	14,297	25.000 %		18
56.		10.000 %	12,379	25.000 %		16
57.		10.000 %	15,490	25.000 %		20
58.		10.000 %	11,884	25.000 %		15
59.		10.000 %	12,135	25.000 %		15
60.		10.000 %	11,565	25.000 %		16
61.		10.000 %	13,183	25.000 %		16
62.		10.000 %	15,231	25.000 %		18
63.		10.000 %	13,818	25.000 %		18
64.		10.000 %	13,856	25.000 %		16
65.		10.000 %	13,856	25.000 %		18
66.		10.000 %	14,089	25.000 %		18
67.		10.000 %	15,482	25.000 %		18
68.		10.000 %	14,461	25.000 %		19
69.		10.000 %	12,947	25.000 %		16
70.		10.000 %	14,030	25.000 %		18
71.		10.000 %	12,464	25.000 %		16
72.		10.000 %	14,369	25.000 %		18
73.		10.000 %	15,016	25.000 %		19
74.		10.000 %	13,685	25.000 %		17
75.		10.000 %	13,685	25.000 %		16
76.		10.000 %	13,630	25.000 %		16
77.		10.000 %	14,851	25.000 %		16
78.		10.000 %	13,263	25.000 %		16
79.		10.000 %	13,263	25.000 %		15
80.		10.000 %	13,727	25.000 %		16
81.		10.000 %	12,525	25.000 %		16
82.		10.000 %	12,525	25.000 %		15
83.		10.000 %	13,323	25.000 %		16
84.		10.000 %	13,665	25.000 %		17
85.		10.000 %	13,726	25.000 %		18
86.		10.000 %	13,510	25.000 %		18
87.		10.000 %	12,707	25.000 %		16
88.		10.000 %	12,707	25.000 %		15
89.		10.000 %	13,789	25.000 %		18
90.		10.000 %	21,140	25.000 %		15
91.		10.000 %	14,037	25.000 %		19
92.		10.000 %	12,868	25.000 %		16
93.		10.000 %	12,868	25.000 %		15
94.		10.000 %	13,225	25.000 %		17
95.		10.000 %	13,142	25.000 %		18
96.		10.000 %	12,554	25.000 %		16
97.		10.000 %	12,554	25.000 %		15
98.		10.000 %	13,421	25.000 %		16
99.		10.000 %	13,171	25.000 %		16
100.		10.000 %	13,115	25.000 %		16
101.		10.000 %	12,868	25.000 %		16
102.		10.000 %	12,039	25.000 %		15
103.		10.000 %	12,629	25.000 %		15
104.		10.000 %	11,608	25.000 %		15

	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)
105.		10.000 %	13,818	25.000 %		18
106.		10.000 %	13,409	25.000 %		18
107.		10.000 %	12,920	25.000 %		16
108.		10.000 %	12,920	25.000 %		16
109.		10.000 %	14,536	25.000 %		17
110.		10.000 %	14,536	25.000 %		17
111.		10.000 %	13,884	25.000 %		18
112.		10.000 %	14,802	25.000 %		18
113.		10.000 %	12,961	25.000 %		16
114.		10.000 %	10,884	25.000 %		15
115.		10.000 %	13,795	25.000 %		16
116.		10.000 %	13,615	25.000 %		16
117.		10.000 %	13,615	25.000 %		19
118.		10.000 %	15,622	25.000 %		15
119.		10.000 %	16,895	25.000 %		17
120.		10.000 %	14,181	25.000 %		18
121.		10.000 %	13,852	25.000 %		16
122.		10.000 %	13,983	25.000 %		17
123.		10.000 %	14,027	25.000 %		16
124.		10.000 %	13,660	25.000 %		18
125.		10.000 %	12,449	25.000 %		16
126.		10.000 %	12,449	25.000 %		15
127.		10.000 %	13,401	25.000 %		16
128.		10.000 %	14,397	25.000 %		18
129.		10.000 %	13,420	25.000 %		16
130.		10.000 %	16,349	25.000 %		18
131.		10.000 %	13,743	25.000 %		18
132.		10.000 %	14,134	25.000 %		19
133.		10.000 %	13,407	25.000 %		16
134.		10.000 %	14,186	25.000 %		15
135.		10.000 %	13,460	25.000 %		16
136.		10.000 %	12,372	25.000 %		16
137.		10.000 %	12,372	25.000 %		15
138.		10.000 %	11,608	25.000 %		15
139.		10.000 %	12,868	25.000 %		16
140.		10.000 %	13,891	25.000 %		17
141.		10.000 %	12,157	25.000 %		15
142.		10.000 %	13,667	25.000 %		18
143.		10.000 %	13,426	25.000 %		16
144.		10.000 %	13,094	25.000 %		16
145.		10.000 %	13,228	25.000 %		16
146.		10.000 %	13,686	25.000 %		16
147.		10.000 %	13,609	25.000 %		16
148.		10.000 %	19,714	25.000 %		16
149.		10.000 %	19,714	25.000 %		15
150.		10.000 %	20,835	25.000 %		17
151.		10.000 %	21,049	25.000 %		17
152.		10.000 %	15,027	25.000 %		14
153.		10.000 %	19,074	25.000 %		17
154.		10.000 %	17,059	25.000 %		14
155.		10.000 %	17,059	25.000 %		17
156.		10.000 %	17,059	25.000 %		17
157.		10.000 %	13,263	25.000 %		16

	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)
158.		10.000 %	11,331	25.000 %		15
159.		10.000 %	19,488	25.000 %		18
160.		10.000 %	19,488	25.000 %		16
161.		10.000 %	14,207	25.000 %		13
162.		10.000 %	14,207	25.000 %		16
163.		10.000 %	18,966	25.000 %		17
164.		10.000 %	18,966	25.000 %		17
165.		10.000 %	19,703	25.000 %		16
166.		10.000 %	19,703	25.000 %		17
167.		10.000 %	12,892	25.000 %		14
168.		10.000 %	13,084	25.000 %		15
169.		10.000 %	19,184	25.000 %		16
170.		10.000 %	19,184	25.000 %		17
171.		10.000 %	19,184	25.000 %		17
172.		10.000 %	14,104	25.000 %		16
173.		10.000 %	14,948	25.000 %		18
174.		10.000 %	14,948	25.000 %		15
175.		10.000 %	27,877	25.000 %		17
176.		10.000 %	27,877	25.000 %		18
177.		10.000 %	20,668	25.000 %		17
178.		10.000 %	20,668	25.000 %		17
179.		10.000 %	20,668	25.000 %		15
180.		10.000 %	21,623	25.000 %		17
181.		10.000 %	21,623	25.000 %		16
182.		10.000 %	20,978	25.000 %		17
183.		10.000 %	20,978	25.000 %		17
184.		10.000 %	20,978	25.000 %		16
185.		10.000 %	22,832	25.000 %		17
186.		10.000 %	22,916	25.000 %		17
187.		10.000 %	43,412	25.000 %		53
188.		10.000 %	19,521	25.000 %		17
189.		10.000 %	19,521	25.000 %		17
190.		10.000 %	19,521	25.000 %		16
191.		10.000 %	24,019	25.000 %		17
192.		10.000 %	21,222	25.000 %		17
193.		10.000 %	21,222	25.000 %		16
194.		10.000 %	19,753	25.000 %		16
195.		10.000 %	19,753	25.000 %		17
196.		10.000 %	19,753	25.000 %		15
197.		10.000 %	22,629	25.000 %		17
198.		10.000 %	24,641	25.000 %		17
199.		10.000 %	28,059	25.000 %		17
200.		10.000 %	28,059	25.000 %		18
201.		10.000 %	17,813	25.000 %		14
202.		10.000 %	27,689	25.000 %		17
203.		10.000 %	27,689	25.000 %		18
204.		10.000 %	21,503	25.000 %		17
205.		10.000 %	21,503	25.000 %		17
206.		10.000 %	18,383	25.000 %		16
207.		10.000 %	18,383	25.000 %		17
208.		10.000 %	21,673	25.000 %		17
209.		10.000 %	21,673	25.000 %		17
210.		10.000 %	18,061	25.000 %		16

	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)
211.		10.000 %	18,061	25.000 %		17
212.		10.000 %	21,871	25.000 %		17
213.		10.000 %	21,871	25.000 %		17
214.		10.000 %	22,627	25.000 %		17
215.		10.000 %	22,627	25.000 %		17
216.		10.000 %	21,528	25.000 %		17
217.		10.000 %	21,528	25.000 %		16
218.		10.000 %	21,402	25.000 %		17
219.		10.000 %	21,402	25.000 %		16
220.		10.000 %	15,848	25.000 %		16
221.		10.000 %	18,346	25.000 %		17
222.		10.000 %	18,346	25.000 %		17
223.		10.000 %	17,854	25.000 %		17
224.		10.000 %	17,854	25.000 %		17
225.		10.000 %	18,582	25.000 %		17
226.		10.000 %	18,582	25.000 %		17
227.		10.000 %	17,786	25.000 %		18
228.		10.000 %	17,786	25.000 %		17
229.		10.000 %	22,013	25.000 %		17
230.		10.000 %	22,013	25.000 %		15
231.		10.000 %	15,661	25.000 %		19
232.		10.000 %	15,661	25.000 %		17
233.		10.000 %	17,249	25.000 %		17
234.		10.000 %	17,249	25.000 %		17
235.		10.000 %	16,502	25.000 %		18
236.		10.000 %	18,213	25.000 %		17
237.		10.000 %	18,213	25.000 %		17
238.		10.000 %	18,213	25.000 %		15
239.		10.000 %	18,182	25.000 %		18
240.		10.000 %	14,942	25.000 %		16
241.		10.000 %	14,942	25.000 %		17
242.		10.000 %	14,942	25.000 %		15
243.		10.000 %	13,059	25.000 %		18
244.		10.000 %	13,059	25.000 %		16
245.		10.000 %	16,574	25.000 %		18
246.		10.000 %	15,002	25.000 %		16
247.		10.000 %	15,002	25.000 %		17
248.		10.000 %	15,002	25.000 %		16
249.		10.000 %	13,232	25.000 %		16
250.		10.000 %	13,818	25.000 %		18
251.		10.000 %	16,471	25.000 %		17
252.		10.000 %	16,089	25.000 %		18
253.		10.000 %	13,471	25.000 %		18
254.		10.000 %	13,407	25.000 %		16
255.		10.000 %	14,280	25.000 %		16
256.		10.000 %	14,280	25.000 %		16
257.		10.000 %	16,852	25.000 %		16
258.		10.000 %	16,852	25.000 %		17
259.		10.000 %	14,900	25.000 %		17
260.		10.000 %	14,900	25.000 %		16
261.		10.000 %	16,151	25.000 %		16
262.		10.000 %	17,043	25.000 %		17
263.		10.000 %	17,043	25.000 %		17

	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)
264.		10.000 %	14,612	25.000 %		16
265.		10.000 %	15,941	25.000 %		16
266.		10.000 %	13,023	25.000 %		16
267.		10.000 %	15,407	25.000 %		16
268.		10.000 %	15,407	25.000 %		17
269.		10.000 %	15,407	25.000 %		16
270.		10.000 %	14,110	25.000 %		17
271.		10.000 %	14,110	25.000 %		16
272.		10.000 %	17,750	25.000 %		17
273.		10.000 %	17,750	25.000 %		17
274.		10.000 %	17,750	25.000 %		17
275.		10.000 %	14,813	25.000 %		18
276.		10.000 %	14,813	25.000 %		16
277.		10.000 %	12,689	25.000 %		15
278.		10.000 %	12,483	25.000 %		18
279.		10.000 %	15,661	25.000 %		16
280.		10.000 %	14,248	25.000 %		16
281.		10.000 %	14,248	25.000 %		15
282.		10.000 %	13,526	25.000 %		16
283.		10.000 %	16,266	25.000 %		16
284.		10.000 %	16,266	25.000 %		17
285.		10.000 %	42,042	25.000 %		53
286.		10.000 %	42,904	25.000 %		51
287.		10.000 %	56,169	25.000 %		54
288.		10.000 %	36,230	25.000 %		17
289.		10.000 %	36,230	25.000 %		15
290.		10.000 %	21,273	25.000 %		33
291.		10.000 %	16,701	25.000 %		16
292.		10.000 %	42,793	25.000 %		51
293.		10.000 %	46,499	25.000 %		52
294.		10.000 %	42,163	25.000 %		70
295.		10.000 %	40,061	25.000 %		53
296.		10.000 %	40,213	25.000 %		51
297.		10.000 %	44,010	25.000 %		52
298.		10.000 %	43,306	25.000 %		51
299.		10.000 %	42,218	25.000 %		51
300.		10.000 %	37,720	25.000 %		51
301.		10.000 %	45,874	25.000 %		53
302.		10.000 %	39,525	25.000 %		53
303.		10.000 %	41,879	25.000 %		49
304.		10.000 %	22,095	25.000 %		33
305.		10.000 %	42,218	25.000 %		51
306.		10.000 %	17,691	25.000 %		16
307.		10.000 %	15,628	25.000 %		15
308.		10.000 %	17,203	25.000 %		17
309.		10.000 %	17,203	25.000 %		15
310.		10.000 %	22,307	25.000 %		17
311.		10.000 %	18,777	25.000 %		20
312.		10.000 %	19,477	25.000 %		18
313.		10.000 %	19,477	25.000 %		17
314.		10.000 %	16,657	25.000 %		15
315.		10.000 %	16,657	25.000 %		17
316.		10.000 %	16,657	25.000 %		17

	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)
317.		10.000 %	19,342	25.000 %		16
318.		10.000 %	19,342	25.000 %		17
319.		10.000 %	19,342	25.000 %		17
320.		10.000 %	19,381	25.000 %		15
321.		10.000 %	19,381	25.000 %		17
322.		10.000 %	17,734	25.000 %		17
323.		10.000 %	17,734	25.000 %		17
324.		10.000 %	18,544	25.000 %		20
325.		10.000 %	19,546	25.000 %		34
326.		10.000 %	51,641	25.000 %		51
327.		10.000 %	22,316	25.000 %		18
328.		10.000 %	51,641	25.000 %		51
329.		10.000 %	16,948	25.000 %		15
330.		10.000 %	16,948	25.000 %		18
331.		10.000 %	19,769	25.000 %		16
332.		10.000 %	19,769	25.000 %		17
333.		10.000 %	57,896	25.000 %		51
334.		10.000 %	49,972	25.000 %		50
335.		10.000 %	18,544	25.000 %		14
336.		10.000 %	18,544	25.000 %		15
337.		10.000 %	20,923	25.000 %		16
338.		10.000 %	20,923	25.000 %		17
339.		10.000 %	15,848	25.000 %		15
340.		10.000 %	16,368	25.000 %		15
341.		10.000 %	13,933	25.000 %		16
342.		10.000 %	18,815	25.000 %		16
343.		10.000 %	11,058	25.000 %		14
344.		10.000 %	16,737	25.000 %		16
345.		10.000 %	15,697	25.000 %		16
346.		10.000 %	17,918	25.000 %		16
347.		10.000 %	19,805	25.000 %		17
348.		10.000 %	11,674	25.000 %		17
349.		10.000 %	12,933	25.000 %		16
350.		10.000 %	17,820	25.000 %		17
351.		10.000 %	17,820	25.000 %		15
352.		10.000 %	14,019	25.000 %		16
353.		10.000 %	20,997	25.000 %		18
354.		10.000 %	21,182	25.000 %		18
355.		10.000 %	20,523	25.000 %		17
356.		10.000 %	19,719	25.000 %		17
357.		10.000 %	17,074	25.000 %		16
358.		10.000 %	17,074	25.000 %		17
359.		10.000 %	17,074	25.000 %		16
360.		10.000 %	17,226	25.000 %		16
361.		10.000 %	14,861	25.000 %		16
362.		10.000 %	15,848	25.000 %		16
363.		10.000 %	17,871	25.000 %		17
364.		10.000 %	17,871	25.000 %		17
365.		10.000 %	17,871	25.000 %		17
366.		10.000 %	14,647	25.000 %		15
367.		10.000 %	16,937	25.000 %		16
368.		10.000 %	16,937	25.000 %		17
369.		10.000 %	16,937	25.000 %		17

	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)
370.		10.000 %	58,530	25.000 %		68
371.		10.000 %	41,914	25.000 %		52
372.		10.000 %	22,362	25.000 %		37

	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.	4,072	3,000	3,000		3,000
2.	4,063	3,000	3,000		3,000
3.	4,063	3,000	3,000		3,000
4.	3,469	3,000	3,000		3,000
5.	4,552	3,000	3,000		3,000
6.	4,552	3,000	3,000		3,000
7.	4,552	3,000	3,000		3,000
8.	3,444	3,000	3,000		3,000
9.	3,444	3,000	3,000		3,000
10.	6,156	3,000	3,000		3,000
11.	4,355	3,000	3,000		3,000
12.	5,397	3,000	3,000		3,000
13.	5,397	3,000	3,000		3,000
14.	5,397	3,000	3,000		3,000
15.	5,099	3,000	3,000		3,000
16.	5,099	3,000	3,000		3,000
17.	5,145	3,000	3,000		3,000
18.	5,145	3,000	3,000		3,000
19.	4,769	3,000	3,000		3,000
20.	4,769	3,000	3,000		3,000
21.	4,965	3,000	3,000		3,000
22.	4,965	3,000	3,000		3,000
23.	4,661	3,000	3,000		3,000
24.	4,661	3,000	3,000		3,000
25.	4,913	3,000	3,000		3,000
26.	4,913	3,000	3,000		3,000
27.	5,305	3,000	3,000		3,000
28.	4,710	3,000	3,000		3,000
29.	4,710	3,000	3,000		3,000
30.	5,367	3,000	3,000		3,000
31.	5,127	3,000	3,000		3,000
32.	4,584	3,000	3,000		3,000
33.	4,584	3,000	3,000		3,000
34.	4,584	3,000	3,000		3,000
35.	4,584	3,000	3,000		3,000
36.	5,132	3,000	3,000		3,000
37.	4,388	3,000	3,000		3,000
38.	4,388	3,000	3,000		3,000
39.	4,745	3,000	3,000		3,000
40.	4,745	3,000	3,000		3,000
41.	4,754	3,000	3,000		3,000
42.	4,754	3,000	3,000		3,000
43.	4,707	3,000	3,000		3,000

	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
44.	4,707	3,000	3,000		3,000
45.	4,707	3,000	3,000		3,000
46.	4,710	3,000	3,000		3,000
47.	4,710	3,000	3,000		3,000
48.	5,307	3,000	3,000		3,000
49.	5,285	3,000	3,000		3,000
50.	5,285	3,000	3,000		3,000
51.	5,363	3,000	3,000		3,000
52.	5,363	3,000	3,000		3,000
53.	4,543	3,000	3,000		3,000
54.	6,623	3,000	3,000		3,000
55.	3,574	3,000	3,000		3,000
56.	3,095	3,000	3,000		3,000
57.	3,873	3,000	3,000		3,000
58.	2,971	2,971	2,971		2,971
59.	3,034	3,000	3,000		3,000
60.	2,891	2,891	2,891		2,891
61.	3,296	3,000	3,000		3,000
62.	3,808	3,000	3,000		3,000
63.	3,455	3,000	3,000		3,000
64.	3,464	3,000	3,000		3,000
65.	3,464	3,000	3,000		3,000
66.	3,522	3,000	3,000		3,000
67.	3,871	3,000	3,000		3,000
68.	3,615	3,000	3,000		3,000
69.	3,237	3,000	3,000		3,000
70.	3,508	3,000	3,000		3,000
71.	3,116	3,000	3,000		3,000
72.	3,592	3,000	3,000		3,000
73.	3,754	3,000	3,000		3,000
74.	3,421	3,000	3,000		3,000
75.	3,421	3,000	3,000		3,000
76.	3,408	3,000	3,000		3,000
77.	3,713	3,000	3,000		3,000
78.	3,316	3,000	3,000		3,000
79.	3,316	3,000	3,000		3,000
80.	3,432	3,000	3,000		3,000
81.	3,131	3,000	3,000		3,000
82.	3,131	3,000	3,000		3,000
83.	3,331	3,000	3,000		3,000
84.	3,416	3,000	3,000		3,000
85.	3,432	3,000	3,000		3,000
86.	3,378	3,000	3,000		3,000
87.	3,177	3,000	3,000		3,000
88.	3,177	3,000	3,000		3,000
89.	3,447	3,000	3,000		3,000
90.	5,285	3,000	3,000		3,000
91.	3,509	3,000	3,000		3,000
92.	3,217	3,000	3,000		3,000
93.	3,217	3,000	3,000		3,000
94.	3,306	3,000	3,000		3,000
95.	3,286	3,000	3,000		3,000
96.	3,139	3,000	3,000		3,000

	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
97.	3,139	3,000	3,000		3,000
98.	3,355	3,000	3,000		3,000
99.	3,293	3,000	3,000		3,000
100.	3,279	3,000	3,000		3,000
101.	3,217	3,000	3,000		3,000
102.	3,010	3,000	3,000		3,000
103.	3,157	3,000	3,000		3,000
104.	2,902	2,902	2,902		2,902
105.	3,455	3,000	3,000		3,000
106.	3,352	3,000	3,000		3,000
107.	3,230	3,000	3,000		3,000
108.	3,230	3,000	3,000		3,000
109.	3,634	3,000	3,000		3,000
110.	3,634	3,000	3,000		3,000
111.	3,471	3,000	3,000		3,000
112.	3,701	3,000	3,000		3,000
113.	3,240	3,000	3,000		3,000
114.	2,721	2,721	2,721		2,721
115.	3,449	3,000	3,000		3,000
116.	3,404	3,000	3,000		3,000
117.	3,404	3,000	3,000		3,000
118.	3,906	3,000	3,000		3,000
119.	4,224	3,000	3,000		3,000
120.	3,545	3,000	3,000		3,000
121.	3,463	3,000	3,000		3,000
122.	3,496	3,000	3,000		3,000
123.	3,507	3,000	3,000		3,000
124.	3,415	3,000	3,000		3,000
125.	3,112	3,000	3,000		3,000
126.	3,112	3,000	3,000		3,000
127.	3,350	3,000	3,000		3,000
128.	3,599	3,000	3,000		3,000
129.	3,355	3,000	3,000		3,000
130.	4,087	3,000	3,000		3,000
131.	3,436	3,000	3,000		3,000
132.	3,534	3,000	3,000		3,000
133.	3,352	3,000	3,000		3,000
134.	3,547	3,000	3,000		3,000
135.	3,365	3,000	3,000		3,000
136.	3,093	3,000	3,000		3,000
137.	3,093	3,000	3,000		3,000
138.	2,902	2,902	2,902		2,902
139.	3,217	3,000	3,000		3,000
140.	3,473	3,000	3,000		3,000
141.	3,039	3,000	3,000		3,000
142.	3,417	3,000	3,000		3,000
143.	3,357	3,000	3,000		3,000
144.	3,274	3,000	3,000		3,000
145.	3,307	3,000	3,000		3,000
146.	3,422	3,000	3,000		3,000
147.	3,402	3,000	3,000		3,000
148.	4,929	3,000	3,000		3,000
149.	4,929	3,000	3,000		3,000

	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
150.	5,209	3,000	3,000		3,000
151.	5,262	3,000	3,000		3,000
152.	3,757	3,000	3,000		3,000
153.	4,769	3,000	3,000		3,000
154.	4,265	3,000	3,000		3,000
155.	4,265	3,000	3,000		3,000
156.	4,265	3,000	3,000		3,000
157.	3,316	3,000	3,000		3,000
158.	2,833	2,832	2,832		2,832
159.	4,872	3,000	3,000		3,000
160.	4,872	3,000	3,000		3,000
161.	3,552	3,000	3,000		3,000
162.	3,552	3,000	3,000		3,000
163.	4,742	3,000	3,000		3,000
164.	4,742	3,000	3,000		3,000
165.	4,926	3,000	3,000		3,000
166.	4,926	3,000	3,000		3,000
167.	3,223	3,000	3,000		3,000
168.	3,271	3,000	3,000		3,000
169.	4,796	3,000	3,000		3,000
170.	4,796	3,000	3,000		3,000
171.	4,796	3,000	3,000		3,000
172.	3,526	3,000	3,000		3,000
173.	3,737	3,000	3,000		3,000
174.	3,737	3,000	3,000		3,000
175.	6,969	3,000	3,000		3,000
176.	6,969	3,000	3,000		3,000
177.	5,167	3,000	3,000		3,000
178.	5,167	3,000	3,000		3,000
179.	5,167	3,000	3,000		3,000
180.	5,406	3,000	3,000		3,000
181.	5,406	3,000	3,000		3,000
182.	5,245	3,000	3,000		3,000
183.	5,245	3,000	3,000		3,000
184.	5,245	3,000	3,000		3,000
185.	5,708	3,000	3,000		3,000
186.	5,729	3,000	3,000		3,000
187.	10,853	3,000	3,000		3,000
188.	4,880	3,000	3,000		3,000
189.	4,880	3,000	3,000		3,000
190.	4,880	3,000	3,000		3,000
191.	6,005	3,000	3,000		3,000
192.	5,306	3,000	3,000		3,000
193.	5,306	3,000	3,000		3,000
194.	4,938	3,000	3,000		3,000
195.	4,938	3,000	3,000		3,000
196.	4,938	3,000	3,000		3,000
197.	5,657	3,000	3,000		3,000
198.	6,160	3,000	3,000		3,000
199.	7,015	3,000	3,000		3,000
200.	7,015	3,000	3,000		3,000
201.	4,453	3,000	3,000		3,000
202.	6,922	3,000	3,000		3,000

	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
203.	6,922	3,000	3,000		3,000
204.	5,376	3,000	3,000		3,000
205.	5,376	3,000	3,000		3,000
206.	4,596	3,000	3,000		3,000
207.	4,596	3,000	3,000		3,000
208.	5,418	3,000	3,000		3,000
209.	5,418	3,000	3,000		3,000
210.	4,515	3,000	3,000		3,000
211.	4,515	3,000	3,000		3,000
212.	5,468	3,000	3,000		3,000
213.	5,468	3,000	3,000		3,000
214.	5,657	3,000	3,000		3,000
215.	5,657	3,000	3,000		3,000
216.	5,382	3,000	3,000		3,000
217.	5,382	3,000	3,000		3,000
218.	5,351	3,000	3,000		3,000
219.	5,351	3,000	3,000		3,000
220.	3,962	3,000	3,000		3,000
221.	4,587	3,000	3,000		3,000
222.	4,587	3,000	3,000		3,000
223.	4,464	3,000	3,000		3,000
224.	4,464	3,000	3,000		3,000
225.	4,646	3,000	3,000		3,000
226.	4,646	3,000	3,000		3,000
227.	4,447	3,000	3,000		3,000
228.	4,447	3,000	3,000		3,000
229.	5,503	3,000	3,000		3,000
230.	5,503	3,000	3,000		3,000
231.	3,915	3,000	3,000		3,000
232.	3,915	3,000	3,000		3,000
233.	4,312	3,000	3,000		3,000
234.	4,312	3,000	3,000		3,000
235.	4,126	3,000	3,000		3,000
236.	4,553	3,000	3,000		3,000
237.	4,553	3,000	3,000		3,000
238.	4,553	3,000	3,000		3,000
239.	4,546	3,000	3,000		3,000
240.	3,736	3,000	3,000		3,000
241.	3,736	3,000	3,000		3,000
242.	3,736	3,000	3,000		3,000
243.	3,265	3,000	3,000		3,000
244.	3,265	3,000	3,000		3,000
245.	4,144	3,000	3,000		3,000
246.	3,751	3,000	3,000		3,000
247.	3,751	3,000	3,000		3,000
248.	3,751	3,000	3,000		3,000
249.	3,308	3,000	3,000		3,000
250.	3,455	3,000	3,000		3,000
251.	4,118	3,000	3,000		3,000
252.	4,022	3,000	3,000		3,000
253.	3,368	3,000	3,000		3,000
254.	3,352	3,000	3,000		3,000
255.	3,570	3,000	3,000		3,000

	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
256.	3,570	3,000	3,000		3,000
257.	4,213	3,000	3,000		3,000
258.	4,213	3,000	3,000		3,000
259.	3,725	3,000	3,000		3,000
260.	3,725	3,000	3,000		3,000
261.	4,038	3,000	3,000		3,000
262.	4,261	3,000	3,000		3,000
263.	4,261	3,000	3,000		3,000
264.	3,653	3,000	3,000		3,000
265.	3,985	3,000	3,000		3,000
266.	3,256	3,000	3,000		3,000
267.	3,852	3,000	3,000		3,000
268.	3,852	3,000	3,000		3,000
269.	3,852	3,000	3,000		3,000
270.	3,528	3,000	3,000		3,000
271.	3,528	3,000	3,000		3,000
272.	4,438	3,000	3,000		3,000
273.	4,438	3,000	3,000		3,000
274.	4,438	3,000	3,000		3,000
275.	3,703	3,000	3,000		3,000
276.	3,703	3,000	3,000		3,000
277.	3,172	3,000	3,000		3,000
278.	3,121	3,000	3,000		3,000
279.	3,915	3,000	3,000		3,000
280.	3,562	3,000	3,000		3,000
281.	3,562	3,000	3,000		3,000
282.	3,382	3,000	3,000		3,000
283.	4,067	3,000	3,000		3,000
284.	4,067	3,000	3,000		3,000
285.	10,511	3,000	3,000		3,000
286.	10,726	3,000	3,000		3,000
287.	14,042	3,000	3,000		3,000
288.	9,058	3,000	3,000		3,000
289.	9,058	3,000	3,000		3,000
290.	5,318	3,000	3,000		3,000
291.	4,175	3,000	3,000		3,000
292.	10,698	3,000	3,000		3,000
293.	11,625	3,000	3,000		3,000
294.	10,541	3,000	3,000		3,000
295.	10,015	3,000	3,000		3,000
296.	10,053	3,000	3,000		3,000
297.	11,003	3,000	3,000		3,000
298.	10,827	3,000	3,000		3,000
299.	10,555	3,000	3,000		3,000
300.	9,430	3,000	3,000		3,000
301.	11,469	3,000	3,000		3,000
302.	9,881	3,000	3,000		3,000
303.	10,470	3,000	3,000		3,000
304.	5,524	3,000	3,000		3,000
305.	10,555	3,000	3,000		3,000
306.	4,423	3,000	3,000		3,000
307.	3,907	3,000	3,000		3,000
308.	4,301	3,000	3,000		3,000

	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
309.	4,301	3,000	3,000		3,000
310.	5,577	3,000	3,000		3,000
311.	4,694	3,000	3,000		3,000
312.	4,869	3,000	3,000		3,000
313.	4,869	3,000	3,000		3,000
314.	4,164	3,000	3,000		3,000
315.	4,164	3,000	3,000		3,000
316.	4,164	3,000	3,000		3,000
317.	4,836	3,000	3,000		3,000
318.	4,836	3,000	3,000		3,000
319.	4,836	3,000	3,000		3,000
320.	4,845	3,000	3,000		3,000
321.	4,845	3,000	3,000		3,000
322.	4,434	3,000	3,000		3,000
323.	4,434	3,000	3,000		3,000
324.	4,636	3,000	3,000		3,000
325.	4,887	3,000	3,000		3,000
326.	12,910	3,000	3,000		3,000
327.	5,579	3,000	3,000		3,000
328.	12,910	3,000	3,000		3,000
329.	4,237	3,000	3,000		3,000
330.	4,237	3,000	3,000		3,000
331.	4,942	3,000	3,000		3,000
332.	4,942	3,000	3,000		3,000
333.	14,474	3,000	3,000		3,000
334.	12,493	3,000	3,000		3,000
335.	4,636	3,000	3,000		3,000
336.	4,636	3,000	3,000		3,000
337.	5,231	3,000	3,000		3,000
338.	5,231	3,000	3,000		3,000
339.	3,962	3,000	3,000		3,000
340.	4,092	3,000	3,000		3,000
341.	3,483	3,000	3,000		3,000
342.	4,704	3,000	3,000		3,000
343.	2,765	2,764	2,764		2,764
344.	4,184	3,000	3,000		3,000
345.	3,924	3,000	3,000		3,000
346.	4,480	3,000	3,000		3,000
347.	4,951	3,000	3,000		3,000
348.	2,919	2,918	2,918		2,918
349.	3,233	3,000	3,000		3,000
350.	4,455	3,000	3,000		3,000
351.	4,455	3,000	3,000		3,000
352.	3,505	3,000	3,000		3,000
353.	5,249	3,000	3,000		3,000
354.	5,296	3,000	3,000		3,000
355.	5,131	3,000	3,000		3,000
356.	4,930	3,000	3,000		3,000
357.	4,269	3,000	3,000		3,000
358.	4,269	3,000	3,000		3,000
359.	4,269	3,000	3,000		3,000
360.	4,307	3,000	3,000		3,000
361.	3,715	3,000	3,000		3,000

	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
362.	3,962	3,000	3,000		3,000
363.	4,468	3,000	3,000		3,000
364.	4,468	3,000	3,000		3,000
365.	4,468	3,000	3,000		3,000
366.	3,662	3,000	3,000		3,000
367.	4,234	3,000	3,000		3,000
368.	4,234	3,000	3,000		3,000
369.	4,234	3,000	3,000		3,000
370.	14,633	3,000	3,000		3,000
371.	10,479	3,000	3,000		3,000
372.	5,591	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 1,114,901 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
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- 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
Selma Yam	(416) 345-6827

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 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 614,991,753

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	434a	Powerline Technician	Apprentice 1
2.	309a	Electrician-Construction and Maintenance	Apprentice 2
3.	309a	Electrician-Construction and Maintenance	Apprentice 3
4.	434a	Powerline Technician	Apprentice 4
5.	434a	Powerline Technician	Apprentice 5
6.	434a	Powerline Technician	Apprentice 6
7.	434a	Powerline Technician	Apprentice 7
8.	434a	Powerline Technician	Apprentice 8
9.	434a	Powerline Technician	Apprentice 9
10.	434a	Powerline Technician	Apprentice 10
11.	434a	Powerline Technician	Apprentice 11
12.	434a	Powerline Technician	Apprentice 12
13.	434a	Powerline Technician	Apprentice 13
14.	434a	Powerline Technician	Apprentice 14
15.	434a	Powerline Technician	Apprentice 15
16.	309a	Electrician-Construction and Maintenance	Apprentice 16
17.	309a	Electrician-Construction and Maintenance	Apprentice 17
18.	309a	Electrician-Construction and Maintenance	Apprentice 18
19.	434a	Powerline Technician	Apprentice 19
20.	434a	Powerline Technician	Apprentice 20
21.	434a	Powerline Technician	Apprentice 21
22.	434a	Powerline Technician	Apprentice 22
23.	434a	Powerline Technician	Apprentice 23
24.	434a	Powerline Technician	Apprentice 24
25.	434a	Powerline Technician	Apprentice 25
26.	434a	Powerline Technician	Apprentice 26
27.	434a	Powerline Technician	Apprentice 27

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
28.	434a	Powerline Technician	Apprentice 28
29.	434a	Powerline Technician	Apprentice 29
30.	434a	Powerline Technician	Apprentice 30
31.	434a	Powerline Technician	Apprentice 31
32.	434a	Powerline Technician	Apprentice 32
33.	434a	Powerline Technician	Apprentice 33
34.	434a	Powerline Technician	Apprentice 34
35.	434a	Powerline Technician	Apprentice 35
36.	434a	Powerline Technician	Apprentice 36
37.	434a	Powerline Technician	Apprentice 37
38.	434a	Powerline Technician	Apprentice 38
39.	434a	Powerline Technician	Apprentice 39
40.	434a	Powerline Technician	Apprentice 40
41.	434a	Powerline Technician	Apprentice 41
42.	434a	Powerline Technician	Apprentice 42
43.	434a	Powerline Technician	Apprentice 43
44.	434a	Powerline Technician	Apprentice 44
45.	434a	Powerline Technician	Apprentice 45
46.	434a	Powerline Technician	Apprentice 46
47.	434a	Powerline Technician	Apprentice 47
48.	434a	Powerline Technician	Apprentice 48
49.	434a	Powerline Technician	Apprentice 49
50.	434a	Powerline Technician	Apprentice 50
51.	434a	Powerline Technician	Apprentice 51
52.	434a	Powerline Technician	Apprentice 52
53.	434a	Powerline Technician	Apprentice 53
54.	434a	Powerline Technician	Apprentice 54
55.	434a	Powerline Technician	Apprentice 55
56.	434a	Powerline Technician	Apprentice 56
57.	434a	Powerline Technician	Apprentice 57
58.	434a	Powerline Technician	Apprentice 58
59.	434a	Powerline Technician	Apprentice 59
60.	434a	Powerline Technician	Apprentice 60
61.	434a	Powerline Technician	Apprentice 61
62.	434a	Powerline Technician	Apprentice 62
63.	434a	Powerline Technician	Apprentice 63
64.	310t	Truck And Coach Technician	Apprentice 64
65.	433a	Industrial Mechanic (Millwright)	Apprentice 65
66.	309a	Electrician-Construction and Maintenance	Apprentice 66
67.	309a	Electrician-Construction and Maintenance	Apprentice 67
68.	309a	Electrician-Construction and Maintenance	Apprentice 68
69.	309a	Electrician-Construction and Maintenance	Apprentice 69
70.	309a	Electrician-Construction and Maintenance	Apprentice 70
71.	309a	Electrician-Construction and Maintenance	Apprentice 71
72.	309a	Electrician-Construction and Maintenance	Apprentice 72
73.	309a	Electrician-Construction and Maintenance	Apprentice 73
74.	309a	Electrician-Construction and Maintenance	Apprentice 74
75.	309a	Electrician-Construction and Maintenance	Apprentice 75
76.	309a	Electrician-Construction and Maintenance	Apprentice 76
77.	309a	Electrician-Construction and Maintenance	Apprentice 77
78.	309a	Electrician-Construction and Maintenance	Apprentice 78
79.	309a	Electrician-Construction and Maintenance	Apprentice 79
80.	309a	Electrician-Construction and Maintenance	Apprentice 80
81.	309a	Electrician-Construction and Maintenance	Apprentice 81
82.	309a	Electrician-Construction and Maintenance	Apprentice 82

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
83.	309a	Electrician-Construction and Maintenance	Apprentice 83
84.	309a	Electrician-Construction and Maintenance	Apprentice 84
85.	309a	Electrician-Construction and Maintenance	Apprentice 85
86.	309a	Electrician-Construction and Maintenance	Apprentice 86
87.	309a	Electrician-Construction and Maintenance	Apprentice 87
88.	309a	Electrician-Construction and Maintenance	Apprentice 88
89.	309a	Electrician-Construction and Maintenance	Apprentice 89
90.	434a	Powerline Technician	Apprentice 90
91.	309a	Electrician-Construction and Maintenance	Apprentice 91
92.	434a	Powerline Technician	Apprentice 92
93.	434a	Powerline Technician	Apprentice 93
94.	434a	Powerline Technician	Apprentice 94
95.	309a	Electrician-Construction and Maintenance	Apprentice 95
96.	309a	Electrician-Construction and Maintenance	Apprentice 96
97.	309a	Electrician-Construction and Maintenance	Apprentice 97
98.	309a	Electrician-Construction and Maintenance	Apprentice 98
99.	309a	Electrician-Construction and Maintenance	Apprentice 99
100.	434a	Powerline Technician	Apprentice 100
101.	434a	Powerline Technician	Apprentice 101
102.	434a	Powerline Technician	Apprentice 102
103.	309a	Electrician-Construction and Maintenance	Apprentice 103
104.	309a	Electrician-Construction and Maintenance	Apprentice 104
105.	309a	Electrician-Construction and Maintenance	Apprentice 105
106.	309a	Electrician-Construction and Maintenance	Apprentice 106
107.	309a	Electrician-Construction and Maintenance	Apprentice 107
108.	309a	Electrician-Construction and Maintenance	Apprentice 108
109.	310t	Truck And Coach Technician	Apprentice 109
110.	310t	Truck And Coach Technician	Apprentice 110
111.	310t	Truck And Coach Technician	Apprentice 111
112.	310t	Truck And Coach Technician	Apprentice 112
113.	433a	Industrial Mechanic (Millwright)	Apprentice 113
114.	309a	Electrician-Construction and Maintenance	Apprentice 114
115.	309a	Electrician-Construction and Maintenance	Apprentice 115
116.	309a	Electrician-Construction and Maintenance	Apprentice 116
117.	309a	Electrician-Construction and Maintenance	Apprentice 117
118.	309a	Electrician-Construction and Maintenance	Apprentice 118
119.	434a	Powerline Technician	Apprentice 119
120.	309a	Electrician-Construction and Maintenance	Apprentice 120
121.	309a	Electrician-Construction and Maintenance	Apprentice 121
122.	309a	Electrician-Construction and Maintenance	Apprentice 122
123.	434a	Powerline Technician	Apprentice 123
124.	434a	Powerline Technician	Apprentice 124
125.	434a	Powerline Technician	Apprentice 125
126.	434a	Powerline Technician	Apprentice 126
127.	434a	Powerline Technician	Apprentice 127
128.	434a	Powerline Technician	Apprentice 128
129.	434a	Powerline Technician	Apprentice 129
130.	434a	Powerline Technician	Apprentice 130
131.	434a	Powerline Technician	Apprentice 131
132.	434a	Powerline Technician	Apprentice 132
133.	434a	Powerline Technician	Apprentice 133
134.	434a	Powerline Technician	Apprentice 134
135.	434a	Powerline Technician	Apprentice 135
136.	434a	Powerline Technician	Apprentice 136
137.	434a	Powerline Technician	Apprentice 137

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
138.	434a	Powerline Technician	Apprentice 138
139.	309a	Electrician-Construction and Maintenance	Apprentice 139
140.	434a	Powerline Technician	Apprentice 140
141.	434a	Powerline Technician	Apprentice 141
142.	434a	Powerline Technician	Apprentice 142
143.	434a	Powerline Technician	Apprentice 143
144.	434a	Powerline Technician	Apprentice 144
145.	434a	Powerline Technician	Apprentice 145
146.	434a	Powerline Technician	Apprentice 146
147.	434a	Powerline Technician	Apprentice 147
148.	434a	Powerline Technician	Apprentice 148
149.	434a	Powerline Technician	Apprentice 149
150.	434a	Powerline Technician	Apprentice 150
151.	434a	Powerline Technician	Apprentice 151
152.	434a	Powerline Technician	Apprentice 152
153.	434a	Powerline Technician	Apprentice 153
154.	434a	Powerline Technician	Apprentice 154
155.	434a	Powerline Technician	Apprentice 155
156.	434a	Powerline Technician	Apprentice 156
157.	434a	Powerline Technician	Apprentice 157
158.	434a	Powerline Technician	Apprentice 158
159.	434a	Powerline Technician	Apprentice 159
160.	434a	Powerline Technician	Apprentice 160
161.	434a	Powerline Technician	Apprentice 161
162.	434a	Powerline Technician	Apprentice 162
163.	434a	Powerline Technician	Apprentice 163
164.	434a	Powerline Technician	Apprentice 164
165.	434a	Powerline Technician	Apprentice 165
166.	434a	Powerline Technician	Apprentice 166
167.	434a	Powerline Technician	Apprentice 167
168.	434a	Powerline Technician	Apprentice 168
169.	434a	Powerline Technician	Apprentice 169
170.	434a	Powerline Technician	Apprentice 170
171.	434a	Powerline Technician	Apprentice 171
172.	434a	Powerline Technician	Apprentice 172
173.	434a	Powerline Technician	Apprentice 173
174.	434a	Powerline Technician	Apprentice 174
175.	434a	Powerline Technician	Apprentice 175
176.	434a	Powerline Technician	Apprentice 176
177.	309a	Electrician-Construction and Maintenance	Apprentice 177
178.	433a	Industrial Mechanic (Millwright)	Apprentice 178
179.	434a	Powerline Technician	Apprentice 179
180.	434a	Powerline Technician	Apprentice 180
181.	434a	Powerline Technician	Apprentice 181
182.	434a	Powerline Technician	Apprentice 182
183.	434a	Powerline Technician	Apprentice 183
184.	434a	Powerline Technician	Apprentice 184
185.	434a	Powerline Technician	Apprentice 185
186.	434a	Powerline Technician	Apprentice 186
187.	434a	Powerline Technician	Apprentice 187
188.	434a	Powerline Technician	Apprentice 188
189.	434a	Powerline Technician	Apprentice 189
190.	434a	Powerline Technician	Apprentice 190
191.	434a	Powerline Technician	Apprentice 191
192.	434a	Powerline Technician	Apprentice 192

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
193.	434a	Powerline Technician	Apprentice 193
194.	434a	Powerline Technician	Apprentice 194
195.	434a	Powerline Technician	Apprentice 195
196.	434a	Powerline Technician	Apprentice 196
197.	434a	Powerline Technician	Apprentice 197
198.	434a	Powerline Technician	Apprentice 198
199.	434a	Powerline Technician	Apprentice 199
200.	434a	Powerline Technician	Apprentice 200
201.	434a	Powerline Technician	Apprentice 201
202.	434a	Powerline Technician	Apprentice 202
203.	434a	Powerline Technician	Apprentice 203
204.	434a	Powerline Technician	Apprentice 204
205.	434a	Powerline Technician	Apprentice 205
206.	434a	Powerline Technician	Apprentice 206
207.	309a	Electrician-Construction and Maintenance	Apprentice 207
208.	309a	Electrician-Construction and Maintenance	Apprentice 208
209.	309a	Electrician-Construction and Maintenance	Apprentice 209
210.	309a	Electrician-Construction and Maintenance	Apprentice 210
211.	309a	Electrician-Construction and Maintenance	Apprentice 211
212.	309a	Electrician-Construction and Maintenance	Apprentice 212
213.	309a	Electrician-Construction and Maintenance	Apprentice 213
214.	309a	Electrician-Construction and Maintenance	Apprentice 214
215.	309a	Electrician-Construction and Maintenance	Apprentice 215
216.	309a	Electrician-Construction and Maintenance	Apprentice 216
217.	309a	Electrician-Construction and Maintenance	Apprentice 217
218.	309a	Electrician-Construction and Maintenance	Apprentice 218
219.	309a	Electrician-Construction and Maintenance	Apprentice 219
220.	309a	Electrician-Construction and Maintenance	Apprentice 220
221.	309a	Electrician-Construction and Maintenance	Apprentice 221
222.	309a	Electrician-Construction and Maintenance	Apprentice 222
223.	309a	Electrician-Construction and Maintenance	Apprentice 223
224.	309a	Electrician-Construction and Maintenance	Apprentice 224
225.	309a	Electrician-Construction and Maintenance	Apprentice 225
226.	309a	Electrician-Construction and Maintenance	Apprentice 226
227.	309a	Electrician-Construction and Maintenance	Apprentice 227
228.	309a	Electrician-Construction and Maintenance	Apprentice 228
229.	309a	Electrician-Construction and Maintenance	Apprentice 229
230.	309a	Electrician-Construction and Maintenance	Apprentice 230
231.	309a	Electrician-Construction and Maintenance	Apprentice 231
232.	309a	Electrician-Construction and Maintenance	Apprentice 232
233.	309a	Electrician-Construction and Maintenance	Apprentice 233
234.	309a	Electrician-Construction and Maintenance	Apprentice 234
235.	309a	Electrician-Construction and Maintenance	Apprentice 235
236.	309a	Electrician-Construction and Maintenance	Apprentice 236
237.	309a	Electrician-Construction and Maintenance	Apprentice 237
238.	309a	Electrician-Construction and Maintenance	Apprentice 238
239.	309a	Electrician-Construction and Maintenance	Apprentice 239
240.	309a	Electrician-Construction and Maintenance	Apprentice 240
241.	309a	Electrician-Construction and Maintenance	Apprentice 241
242.	309a	Electrician-Construction and Maintenance	Apprentice 242
243.	309a	Electrician-Construction and Maintenance	Apprentice 243
244.	309a	Electrician-Construction and Maintenance	Apprentice 244
245.	310t	Truck And Coach Technician	Apprentice 245
246.	309a	Electrician-Construction and Maintenance	Apprentice 246
247.	309a	Electrician-Construction and Maintenance	Apprentice 247

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
248.	309a	Electrician-Construction and Maintenance	Apprentice 248
249.	309a	Electrician-Construction and Maintenance	Apprentice 249
250.	309a	Electrician-Construction and Maintenance	Apprentice 250
251.	309a	Electrician-Construction and Maintenance	Apprentice 251
252.	309a	Electrician-Construction and Maintenance	Apprentice 252
253.	309a	Electrician-Construction and Maintenance	Apprentice 253
254.	309a	Electrician-Construction and Maintenance	Apprentice 254
255.	309a	Electrician-Construction and Maintenance	Apprentice 255
256.	309a	Electrician-Construction and Maintenance	Apprentice 256
257.	309a	Electrician-Construction and Maintenance	Apprentice 257
258.	309a	Electrician-Construction and Maintenance	Apprentice 258
259.	310t	Truck And Coach Technician	Apprentice 259
260.	434a	Powerline Technician	Apprentice 260
261.	434a	Powerline Technician	Apprentice 261
262.	434a	Powerline Technician	Apprentice 262
263.	434a	Powerline Technician	Apprentice 263
264.	434a	Powerline Technician	Apprentice 264
265.	434a	Powerline Technician	Apprentice 265
266.	434a	Powerline Technician	Apprentice 266
267.	434a	Powerline Technician	Apprentice 267
268.	434a	Powerline Technician	Apprentice 268
269.	434a	Powerline Technician	Apprentice 269
270.	434a	Powerline Technician	Apprentice 270
271.	434a	Powerline Technician	Apprentice 271
272.	434a	Powerline Technician	Apprentice 272
273.	434a	Powerline Technician	Apprentice 273
274.	434a	Powerline Technician	Apprentice 274
275.	309a	Electrician-Construction and Maintenance	Apprentice 275
276.	309a	Electrician-Construction and Maintenance	Apprentice 276
277.	309a	Electrician-Construction and Maintenance	Apprentice 277
278.	309a	Electrician-Construction and Maintenance	Apprentice 278
279.	309a	Electrician-Construction and Maintenance	Apprentice 279
280.	309a	Electrician-Construction and Maintenance	Apprentice 280
281.	309a	Electrician-Construction and Maintenance	Apprentice 281
282.	309a	Electrician-Construction and Maintenance	Apprentice 282
283.	309a	Electrician-Construction and Maintenance	Apprentice 283
284.	309a	Electrician-Construction and Maintenance	Apprentice 284
285.	309a	Electrician-Construction and Maintenance	Apprentice 285
286.	309a	Electrician-Construction and Maintenance	Apprentice 286
287.	309a	Electrician-Construction and Maintenance	Apprentice 287
288.	309a	Electrician-Construction and Maintenance	Apprentice 288
289.	309a	Electrician-Construction and Maintenance	Apprentice 289
290.	434a	Powerline Technician	Apprentice 290
291.	434a	Powerline Technician	Apprentice 291
292.	434a	Powerline Technician	Apprentice 292
293.	434a	Powerline Technician	Apprentice 293
294.	434a	Powerline Technician	Apprentice 294
295.	434a	Powerline Technician	Apprentice 295
296.	434a	Powerline Technician	Apprentice 296
297.	434a	Powerline Technician	Apprentice 297
298.	434a	Powerline Technician	Apprentice 298
299.	434a	Powerline Technician	Apprentice 299
300.	434a	Powerline Technician	Apprentice 300
301.	434a	Powerline Technician	Apprentice 301
302.	434a	Powerline Technician	Apprentice 302

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
303.	434a	Powerline Technician	Apprentice 303
304.	434a	Powerline Technician	Apprentice 304
305.	434a	Powerline Technician	Apprentice 305
306.	434a	Powerline Technician	Apprentice 306
307.	434a	Powerline Technician	Apprentice 307
308.	434a	Powerline Technician	Apprentice 308
309.	434a	Powerline Technician	Apprentice 309
310.	434a	Powerline Technician	Apprentice 310
311.	434a	Powerline Technician	Apprentice 311
312.	434a	Powerline Technician	Apprentice 312
313.	434a	Powerline Technician	Apprentice 313
314.	434a	Powerline Technician	Apprentice 314
315.	434a	Powerline Technician	Apprentice 315
316.	434a	Powerline Technician	Apprentice 316
317.	434a	Powerline Technician	Apprentice 317
318.	434a	Powerline Technician	Apprentice 318
319.	434a	Powerline Technician	Apprentice 319
320.	434a	Powerline Technician	Apprentice 320
321.	434a	Powerline Technician	Apprentice 321
322.	309a	Electrician-Construction and Maintenance	Apprentice 322
323.	434a	Powerline Technician	Apprentice 323
324.	434a	Powerline Technician	Apprentice 324
325.	434a	Powerline Technician	Apprentice 325
326.	434a	Powerline Technician	Apprentice 326
327.	434a	Powerline Technician	Apprentice 327
328.	434a	Powerline Technician	Apprentice 328
329.	434a	Powerline Technician	Apprentice 329
330.	434a	Powerline Technician	Apprentice 330
331.	434a	Powerline Technician	Apprentice 331
332.	434a	Powerline Technician	Apprentice 332
333.	434a	Powerline Technician	Apprentice 333
334.	434a	Powerline Technician	Apprentice 334
335.	434a	Powerline Technician	Apprentice 335
336.	434a	Powerline Technician	Apprentice 336
337.	434a	Powerline Technician	Apprentice 337
338.	434a	Powerline Technician	Apprentice 338
339.	434a	Powerline Technician	Apprentice 339
340.	434a	Powerline Technician	Apprentice 340
341.	434a	Powerline Technician	Apprentice 341
342.	434a	Powerline Technician	Apprentice 342
343.	434a	Powerline Technician	Apprentice 343
344.	434a	Powerline Technician	Apprentice 344
345.	434a	Powerline Technician	Apprentice 345
346.	434a	Powerline Technician	Apprentice 346
347.	434a	Powerline Technician	Apprentice 347
348.	434a	Powerline Technician	Apprentice 348
349.	434a	Powerline Technician	Apprentice 349
350.	434a	Powerline Technician	Apprentice 350
351.	434a	Powerline Technician	Apprentice 351
352.	434a	Powerline Technician	Apprentice 352
353.	434a	Powerline Technician	Apprentice 353
354.	434a	Powerline Technician	Apprentice 354
355.	309a	Electrician-Construction and Maintenance	Apprentice 355
356.	309a	Electrician-Construction and Maintenance	Apprentice 356
357.	309a	Electrician-Construction and Maintenance	Apprentice 357

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
358.	309a	Electrician-Construction and Maintenance	Apprentice 358
359.	309a	Electrician-Construction and Maintenance	Apprentice 359
360.	309a	Electrician-Construction and Maintenance	Apprentice 360
361.	434a	Powerline Technician	Apprentice 361
362.	434a	Powerline Technician	Apprentice 362
363.	434a	Powerline Technician	Apprentice 363
364.	434a	Powerline Technician	Apprentice 364
365.	434a	Powerline Technician	Apprentice 365
366.	434a	Powerline Technician	Apprentice 366
367.	434a	Powerline Technician	Apprentice 367
368.	434a	Powerline Technician	Apprentice 368
369.	434a	Powerline Technician	Apprentice 369
370.	434a	Powerline Technician	Apprentice 370
371.	434a	Powerline Technician	Apprentice 371
372.	434a	Powerline Technician	Apprentice 372
373.	433a	Industrial Mechanic (Millwright)	Apprentice 373
374.	433a	Industrial Mechanic (Millwright)	Apprentice 374
375.	434a	Powerline Technician	Apprentice 375
376.	434a	Powerline Technician	Apprentice 376
377.	434a	Powerline Technician	Apprentice 377
378.	434a	Powerline Technician	Apprentice 378
379.	434a	Powerline Technician	Apprentice 379
380.	434a	Powerline Technician	Apprentice 380
381.	434a	Powerline Technician	Apprentice 381
382.	434a	Powerline Technician	Apprentice 382
383.	434a	Powerline Technician	Apprentice 383
384.	434a	Powerline Technician	Apprentice 384
385.	309a	Electrician-Construction and Maintenance	Apprentice 385
386.	309a	Electrician-Construction and Maintenance	Apprentice 386
387.	309a	Electrician-Construction and Maintenance	Apprentice 387
388.	309a	Electrician-Construction and Maintenance	Apprentice 388
389.	309a	Electrician-Construction and Maintenance	Apprentice 389
390.	309a	Electrician-Construction and Maintenance	Apprentice 390
391.	309a	Electrician-Construction and Maintenance	Apprentice 391
392.	309a	Electrician-Construction and Maintenance	Apprentice 392
393.	309a	Electrician-Construction and Maintenance	Apprentice 393
394.	309a	Electrician-Construction and Maintenance	Apprentice 394
395.	309a	Electrician-Construction and Maintenance	Apprentice 395
396.	309a	Electrician-Construction and Maintenance	Apprentice 396
397.	309a	Electrician-Construction and Maintenance	Apprentice 397
398.	309a	Electrician-Construction and Maintenance	Apprentice 398
399.	309a	Electrician-Construction and Maintenance	Apprentice 399
400.	309a	Electrician-Construction and Maintenance	Apprentice 400
401.	309a	Electrician-Construction and Maintenance	Apprentice 401
402.	309a	Electrician-Construction and Maintenance	Apprentice 402
403.	309a	Electrician-Construction and Maintenance	Apprentice 403
404.	309a	Electrician-Construction and Maintenance	Apprentice 404
405.	309a	Electrician-Construction and Maintenance	Apprentice 405
406.	309a	Electrician-Construction and Maintenance	Apprentice 406
407.	309a	Electrician-Construction and Maintenance	Apprentice 407
408.	309a	Electrician-Construction and Maintenance	Apprentice 408
409.	309a	Electrician-Construction and Maintenance	Apprentice 409
410.	309a	Electrician-Construction and Maintenance	Apprentice 410
411.	310t	Truck And Coach Technician	Apprentice 411
412.	310t	Truck And Coach Technician	Apprentice 412

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
413.	310t	Truck And Coach Technician	Apprentice 413
414.	309a	Electrician-Construction and Maintenance	Apprentice 414
415.	434a	Powerline Technician	Apprentice 415
416.	434a	Powerline Technician	Apprentice 416
417.	434a	Powerline Technician	Apprentice 417
418.	434a	Powerline Technician	Apprentice 418
419.	434a	Powerline Technician	Apprentice 419
420.	434a	Powerline Technician	Apprentice 420
421.	434a	Powerline Technician	Apprentice 421
422.	434a	Powerline Technician	Apprentice 422
423.	434a	Powerline Technician	Apprentice 423
424.	434a	Powerline Technician	Apprentice 424
425.	434a	Powerline Technician	Apprentice 425
426.	434a	Powerline Technician	Apprentice 426
427.	309a	Electrician-Construction and Maintenance	Apprentice 427
428.	434a	Powerline Technician	Apprentice 428
429.	434a	Powerline Technician	Apprentice 429
430.	309a	Electrician-Construction and Maintenance	Apprentice 430
431.	309a	Electrician-Construction and Maintenance	Apprentice 431
432.	309a	Electrician-Construction and Maintenance	Apprentice 432
433.	309a	Electrician-Construction and Maintenance	Apprentice 433
434.	309a	Electrician-Construction and Maintenance	Apprentice 434
435.	309a	Electrician-Construction and Maintenance	Apprentice 435
436.	434a	Powerline Technician	Apprentice 436
437.	434a	Powerline Technician	Apprentice 437
438.	309a	Electrician-Construction and Maintenance	Apprentice 438
439.	309a	Electrician-Construction and Maintenance	Apprentice 439
440.	309a	Electrician-Construction and Maintenance	Apprentice 440
441.	309a	Electrician-Construction and Maintenance	Apprentice 441
442.	309a	Electrician-Construction and Maintenance	Apprentice 442
443.	309a	Electrician-Construction and Maintenance	Apprentice 443
444.	309a	Electrician-Construction and Maintenance	Apprentice 444
445.	434a	Powerline Technician	Apprentice 445
446.	434a	Powerline Technician	Apprentice 446
447.	309a	Electrician-Construction and Maintenance	Apprentice 447
448.	309a	Electrician-Construction and Maintenance	Apprentice 448
449.	434a	Powerline Technician	Apprentice 449
450.	309a	Electrician-Construction and Maintenance	Apprentice 450
451.	309a	Electrician-Construction and Maintenance	Apprentice 451
452.	309a	Electrician-Construction and Maintenance	Apprentice 452
453.	309a	Electrician-Construction and Maintenance	Apprentice 453
454.	309a	Electrician-Construction and Maintenance	Apprentice 454
455.	309a	Electrician-Construction and Maintenance	Apprentice 455
456.	309a	Electrician-Construction and Maintenance	Apprentice 456
457.	434a	Powerline Technician	Apprentice 457
458.	434a	Powerline Technician	Apprentice 458
459.	434a	Powerline Technician	Apprentice 459
460.	434a	Powerline Technician	Apprentice 460
461.	434a	Powerline Technician	Apprentice 461
462.	434a	Powerline Technician	Apprentice 462
463.	434a	Powerline Technician	Apprentice 463
464.	434a	Powerline Technician	Apprentice 464
465.	434a	Powerline Technician	Apprentice 465
466.	434a	Powerline Technician	Apprentice 466
467.	434a	Powerline Technician	Apprentice 467

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
468.	434a	Powerline Technician	Apprentice 468
469.	434a	Powerline Technician	Apprentice 469
470.	434a	Powerline Technician	Apprentice 470
471.	434a	Powerline Technician	Apprentice 471
472.	309a	Electrician-Construction and Maintenance	Apprentice 472
473.	309a	Electrician-Construction and Maintenance	Apprentice 473
474.	434a	Powerline Technician	Apprentice 474
475.	434a	Powerline Technician	Apprentice 475
476.	434a	Powerline Technician	Apprentice 476
477.	434a	Powerline Technician	Apprentice 477
478.	434a	Powerline Technician	Apprentice 478
479.	434a	Powerline Technician	Apprentice 479
480.	434a	Powerline Technician	Apprentice 480
481.	434a	Powerline Technician	Apprentice 481
482.	434a	Powerline Technician	Apprentice 482
483.	434a	Powerline Technician	Apprentice 483
484.	434a	Powerline Technician	Apprentice 484
485.	434a	Powerline Technician	Apprentice 485
486.	434a	Powerline Technician	Apprentice 486
487.	434a	Powerline Technician	Apprentice 487
488.	434a	Powerline Technician	Apprentice 488
489.	434a	Powerline Technician	Apprentice 489
490.	434a	Powerline Technician	Apprentice 490
491.	434a	Powerline Technician	Apprentice 491
492.	434a	Powerline Technician	Apprentice 492
493.	310t	Truck And Coach Technician	Apprentice 493
494.	310t	Truck And Coach Technician	Apprentice 494
495.	310t	Truck And Coach Technician	Apprentice 495
496.	310t	Truck And Coach Technician	Apprentice 496
497.	309a	Electrician-Construction and Maintenance	Apprentice 497
498.	309a	Electrician-Construction and Maintenance	Apprentice 498
499.	309a	Electrician-Construction and Maintenance	Apprentice 499
500.	309a	Electrician-Construction and Maintenance	Apprentice 500
501.	309a	Electrician-Construction and Maintenance	Apprentice 501
502.	309a	Electrician-Construction and Maintenance	Apprentice 502
503.	309a	Electrician-Construction and Maintenance	Apprentice 503
504.	309a	Electrician-Construction and Maintenance	Apprentice 504
505.	309a	Electrician-Construction and Maintenance	Apprentice 505
506.	309a	Electrician-Construction and Maintenance	Apprentice 506
507.	309a	Electrician-Construction and Maintenance	Apprentice 507
508.	309a	Electrician-Construction and Maintenance	Apprentice 508
509.	309a	Electrician-Construction and Maintenance	Apprentice 509
510.	309a	Electrician-Construction and Maintenance	Apprentice 510
511.	309a	Electrician-Construction and Maintenance	Apprentice 511
512.	309a	Electrician-Construction and Maintenance	Apprentice 512
513.	434a	Powerline Technician	Apprentice 513
514.	434a	Powerline Technician	Apprentice 514
515.	434a	Powerline Technician	Apprentice 515
516.	434a	Powerline Technician	Apprentice 516
517.	434a	Powerline Technician	Apprentice 517
518.	434a	Powerline Technician	Apprentice 518
519.	434a	Powerline Technician	Apprentice 519
520.	434a	Powerline Technician	Apprentice 520
521.	434a	Powerline Technician	Apprentice 521
522.	434a	Powerline Technician	Apprentice 522

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
523.	434a	Powerline Technician	Apprentice 523
524.	434a	Powerline Technician	Apprentice 524
525.	434a	Powerline Technician	Apprentice 525
526.	434a	Powerline Technician	Apprentice 526
527.	434a	Powerline Technician	Apprentice 527
528.	434a	Powerline Technician	Apprentice 528
529.	434a	Powerline Technician	Apprentice 529
530.	434a	Powerline Technician	Apprentice 530
531.	309a	Electrician-Construction and Maintenance	Apprentice 531
532.	309a	Electrician-Construction and Maintenance	Apprentice 532
533.	309a	Electrician-Construction and Maintenance	Apprentice 533
534.	434a	Powerline Technician	Apprentice 534
535.	434a	Powerline Technician	Apprentice 535
536.	434a	Powerline Technician	Apprentice 536
537.	434a	Powerline Technician	Apprentice 537
538.	434a	Powerline Technician	Apprentice 538
539.	434a	Powerline Technician	Apprentice 539
540.	434a	Powerline Technician	Apprentice 540
541.	434a	Powerline Technician	Apprentice 541
542.	434a	Powerline Technician	Apprentice 542
543.	434a	Powerline Technician	Apprentice 543
544.	434a	Powerline Technician	Apprentice 544
545.	434a	Powerline Technician	Apprentice 545
546.	434a	Powerline Technician	Apprentice 546
547.	434a	Powerline Technician	Apprentice 547
548.	434a	Powerline Technician	Apprentice 548
549.	434a	Powerline Technician	Apprentice 549
550.	434a	Powerline Technician	Apprentice 550
551.	309a	Electrician-Construction and Maintenance	Apprentice 551
552.	309a	Electrician-Construction and Maintenance	Apprentice 552
553.	309a	Electrician-Construction and Maintenance	Apprentice 553
554.	309a	Electrician-Construction and Maintenance	Apprentice 554
555.	309a	Electrician-Construction and Maintenance	Apprentice 555
556.	309a	Electrician-Construction and Maintenance	Apprentice 556
557.	309a	Electrician-Construction and Maintenance	Apprentice 557
558.	309a	Electrician-Construction and Maintenance	Apprentice 558
559.	434a	Powerline Technician	Apprentice 559
560.	434a	Powerline Technician	Apprentice 560
561.	434a	Powerline Technician	Apprentice 561
562.	434a	Powerline Technician	Apprentice 562
563.	434a	Powerline Technician	Apprentice 563
564.	434a	Powerline Technician	Apprentice 564
565.	309a	Electrician-Construction and Maintenance	Apprentice 565
566.	434a	Powerline Technician	Apprentice 566
567.	434a	Powerline Technician	Apprentice 567
568.	434a	Powerline Technician	Apprentice 568
569.	434a	Powerline Technician	Apprentice 569
570.	434a	Powerline Technician	Apprentice 570
571.	434a	Powerline Technician	Apprentice 571
572.	434a	Powerline Technician	Apprentice 572
573.	434a	Powerline Technician	Apprentice 573
574.	310t	Truck And Coach Technician	Apprentice 574
575.	310t	Truck And Coach Technician	Apprentice 575
576.	310t	Truck And Coach Technician	Apprentice 576
577.	434a	Powerline Technician	Apprentice 577

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
578.	434a	Powerline Technician	Apprentice 578
579.	434a	Powerline Technician	Apprentice 579
580.	434a	Powerline Technician	Apprentice 580
581.	434a	Powerline Technician	Apprentice 581
582.	434a	Powerline Technician	Apprentice 582
583.	434a	Powerline Technician	Apprentice 583
584.	434a	Powerline Technician	Apprentice 584
585.	434a	Powerline Technician	Apprentice 585
586.	434a	Powerline Technician	Apprentice 586
587.	434a	Powerline Technician	Apprentice 587
588.	434a	Powerline Technician	Apprentice 588
589.	434a	Powerline Technician	Apprentice 589
590.	434a	Powerline Technician	Apprentice 590
591.	309a	Electrician-Construction and Maintenance	Apprentice 591
592.	309a	Electrician-Construction and Maintenance	Apprentice 592
593.	309a	Electrician-Construction and Maintenance	Apprentice 593
594.	309a	Electrician-Construction and Maintenance	Apprentice 594
595.	309a	Electrician-Construction and Maintenance	Apprentice 595
596.	309a	Electrician-Construction and Maintenance	Apprentice 596
597.	309a	Electrician-Construction and Maintenance	Apprentice 597
598.	309a	Electrician-Construction and Maintenance	Apprentice 598
599.	309a	Electrician-Construction and Maintenance	Apprentice 599
600.	309a	Electrician-Construction and Maintenance	Apprentice 600
601.	309a	Electrician-Construction and Maintenance	Apprentice 601
602.	309a	Electrician-Construction and Maintenance	Apprentice 602
603.	309a	Electrician-Construction and Maintenance	Apprentice 603
604.	434a	Powerline Technician	Apprentice 604
605.	434a	Powerline Technician	Apprentice 605
606.	434a	Powerline Technician	Apprentice 606
607.	434a	Powerline Technician	Apprentice 607
608.	434a	Powerline Technician	Apprentice 608
609.	434a	Powerline Technician	Apprentice 609
610.	434a	Powerline Technician	Apprentice 610
611.	434a	Powerline Technician	Apprentice 611

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PA0222	2008-01-21	2012-01-01	2012-01-21
2.	PA0220	2008-02-04	2012-01-01	2012-02-04
3.	PA0221	2008-02-04	2012-01-01	2012-02-04
4.	PB1852	2008-02-19	2012-01-01	2012-02-19
5.	PB1853	2008-02-19	2012-01-01	2012-02-19
6.	PB1854	2008-02-19	2012-01-01	2012-02-19
7.	PB1855	2008-02-19	2012-01-01	2012-02-19
8.	PB1857	2008-02-19	2012-01-01	2012-02-19
9.	PB1858	2008-02-19	2012-01-01	2012-02-19
10.	PB1589	2008-02-19	2012-01-01	2012-02-19
11.	PB1860	2008-02-19	2012-01-01	2012-02-19
12.	PB1862	2008-02-19	2012-01-01	2012-02-19
13.	PB1864	2008-02-19	2012-01-01	2012-02-19
14.	PB1865	2008-02-19	2012-01-01	2012-02-19

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
15.	PB1866	2008-02-19	2012-01-01	2012-02-19
16.	PB0226	2008-03-25	2012-01-01	2012-03-25
17.	PB0227	2008-03-25	2012-01-01	2012-03-25
18.	PB0228	2008-03-25	2012-01-01	2012-03-25
19.	PB1867	2008-03-31	2012-01-01	2012-03-31
20.	PB1883	2008-03-31	2012-01-01	2012-03-31
21.	PB1869	2008-03-31	2012-01-01	2012-03-31
22.	PB1871	2008-03-31	2012-01-01	2012-03-31
23.	PB1872	2008-03-31	2012-01-01	2012-03-31
24.	PB1873	2008-03-31	2012-01-01	2012-03-31
25.	PB1874	2008-03-31	2012-01-01	2012-03-31
26.	PB1875	2008-03-31	2012-01-01	2012-03-31
27.	PB1876	2008-03-31	2012-01-01	2012-03-31
28.	PB1877	2008-03-31	2012-01-01	2012-03-31
29.	PB1878	2008-03-31	2012-01-01	2012-03-31
30.	PB1879	2008-03-31	2012-01-01	2012-03-31
31.	PB1880	2008-03-31	2012-01-01	2012-03-31
32.	PB1881	2008-03-31	2012-01-01	2012-03-31
33.	PB1882	2008-03-31	2012-01-01	2012-03-31
34.	PB1885	2008-04-21	2012-01-01	2012-04-21
35.	PB1887	2008-04-21	2012-01-01	2012-04-21
36.	PB1888	2008-04-21	2012-01-01	2012-04-21
37.	PB1889	2008-04-21	2012-01-01	2012-04-21
38.	PB1890	2008-04-21	2012-01-01	2012-04-21
39.	PB1891	2008-04-21	2012-01-01	2012-04-21
40.	PB1892	2008-04-21	2012-01-01	2012-04-21
41.	PB1893	2008-04-21	2012-01-01	2012-04-21
42.	PB1894	2008-04-21	2012-01-01	2012-04-21
43.	PB1895	2008-04-21	2012-01-01	2012-04-21
44.	PB1896	2008-04-21	2012-01-01	2012-04-21
45.	PB1897	2008-04-21	2012-01-01	2012-04-21
46.	D24331	2008-04-21	2012-01-01	2012-04-21
47.	PB1898	2008-04-21	2012-01-01	2012-04-21
48.	PB1910	2008-05-20	2012-01-01	2012-05-20
49.	PB1913	2008-05-20	2012-01-01	2012-05-20
50.	PB1902	2008-05-20	2012-01-01	2012-05-20
51.	PB1904	2008-05-20	2012-01-01	2012-05-20
52.	PB1911	2008-05-20	2012-01-01	2012-05-20
53.	PB1901	2008-05-20	2012-01-01	2012-05-20
54.	PB1905	2008-05-20	2012-01-01	2012-05-20
55.	PB1903	2008-05-20	2012-01-01	2012-05-20
56.	PB1914	2008-05-20	2012-01-01	2012-05-20
57.	PB1909	2008-05-20	2012-01-01	2012-05-20
58.	PB1912	2008-05-20	2012-01-01	2012-05-20
59.	PB1908	2008-05-20	2012-01-01	2012-05-20
60.	PB1907	2008-05-20	2012-01-01	2012-05-20
61.	PB1899	2008-05-20	2012-01-01	2012-05-20
62.	PB1906	2008-05-20	2012-01-01	2012-05-20
63.	PB1900	2008-05-20	2012-01-01	2012-05-20
64.	AF8125	2008-05-26	2012-03-01	2012-05-26
65.	AG9969	2008-06-02	2012-01-01	2012-06-02
66.	PB1643	2008-06-02	2012-01-01	2012-06-02
67.	PB0247	2008-06-02	2012-01-01	2012-06-02

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
68.	PB1919	2008-06-02	2012-01-01	2012-06-02
69.	PB0257	2008-06-02	2012-01-01	2012-06-02
70.	PB0241	2008-06-02	2012-01-01	2012-06-02
71.	PB0248	2008-06-02	2012-01-01	2012-06-02
72.	PB1917	2008-06-02	2012-01-01	2012-06-02
73.	PA0491	2008-06-02	2012-01-01	2012-06-02
74.	PB1918	2008-06-02	2012-01-01	2012-06-02
75.	PA4673	2008-06-02	2012-01-01	2012-06-02
76.	PB0249	2008-06-02	2012-01-01	2012-06-02
77.	PB0240	2008-06-02	2012-01-01	2012-06-02
78.	PB0252	2008-06-02	2012-01-01	2012-06-02
79.	971667	2008-06-02	2012-01-01	2012-06-02
80.	PB0239	2008-06-02	2012-01-01	2012-06-02
81.	PB2058	2008-06-02	2012-01-01	2012-06-02
82.	PB0235	2008-06-02	2012-01-01	2012-06-02
83.	PB0255	2008-06-02	2012-01-01	2012-06-02
84.	PB0259	2008-06-02	2012-01-01	2012-06-02
85.	PB0238	2008-06-02	2012-01-01	2012-06-02
86.	PB0420	2008-06-02	2012-01-01	2012-06-02
87.	PB0419	2008-06-02	2012-01-01	2012-06-02
88.	PB0256	2008-06-02	2012-01-01	2012-06-02
89.	PB0256	2008-06-02	2012-01-01	2012-06-02
90.	PB1826	2008-06-11	2012-01-01	2012-06-11
91.	PB0230	2008-08-05	2012-01-01	2012-07-11
92.	PB1817	2008-08-11	2012-01-01	2012-08-07
93.	PD1820	2008-08-11	2012-01-01	2012-08-11
94.	PB1822	2008-08-11	2012-01-01	2012-07-05
95.	PB0231	2008-08-25	2012-01-01	2012-08-25
96.	PC1245	2008-09-15	2012-01-01	2012-02-17
97.	PC1247	2008-10-14	2012-01-01	2012-10-14
98.	PB0233	2008-10-14	2012-01-01	2012-10-14
99.	PB0234	2008-10-14	2012-01-01	2012-10-14
100.	PB1827	2008-10-23	2012-01-01	2012-10-23
101.	PB1828	2008-10-23	2012-01-01	2012-09-20
102.	PB1833	2008-10-23	2012-01-01	2012-10-23
103.	PC1248	2008-12-01	2012-01-01	2012-12-01
104.	PC1249	2008-12-01	2012-01-01	2012-12-01
105.	PC1250	2008-12-01	2012-01-01	2012-11-20
106.	PC1251	2008-12-01	2012-01-01	2012-09-07
107.	PC1252	2008-12-01	2012-01-01	2012-12-01
108.	PC1257	2008-12-15	2012-01-01	2012-08-01
109.	AG9781	2009-01-05	2012-01-01	2012-12-31
110.	AG9783	2009-01-05	2012-01-01	2012-08-27
111.	AG9783	2009-01-05	2012-10-26	2012-12-31
112.	AG9782	2009-01-05	2012-01-01	2012-12-31
113.	AD9948	2009-01-12	2012-01-01	2012-12-31
114.	PB0246	2009-01-12	2012-01-01	2012-12-31
115.	PA3471	2009-01-12	2012-01-01	2012-12-31
116.	PB1924	2009-01-12	2012-01-01	2012-12-31
117.	PB5880	2009-01-12	2012-01-01	2012-12-31
118.	PB0244	2009-01-12	2012-01-01	2012-12-31
119.	PC2643	2009-01-23	2012-01-01	2012-12-31
120.	PC1260	2009-02-02	2012-01-01	2012-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
121.	PC1259	2009-02-02	2012-01-01	2012-12-31
122.	PC1261	2009-02-02	2012-01-01	2012-05-24
123.	PB1930	2009-02-02	2012-01-01	2012-12-31
124.	PB1928	2009-02-02	2012-01-01	2012-12-31
125.	PB1929	2009-02-02	2012-01-01	2012-12-31
126.	PB1932	2009-02-02	2012-01-01	2012-12-31
127.	PC2635	2009-02-02	2012-01-01	2012-12-31
128.	PB1926	2009-02-02	2012-01-01	2012-12-31
129.	PB1925	2009-02-02	2012-01-01	2012-12-31
130.	PB1921	2009-02-02	2012-01-01	2012-12-31
131.	PB0245	2009-02-02	2012-01-01	2012-12-31
132.	PC2631	2009-02-02	2012-01-01	2012-12-31
133.	PC2632	2009-02-02	2012-01-01	2012-12-31
134.	PC2634	2009-02-02	2012-01-01	2012-12-31
135.	PC2633	2009-02-02	2012-01-01	2012-12-31
136.	PB1931	2009-02-02	2012-01-01	2012-12-31
137.	PA6242	2009-02-02	2012-01-01	2012-12-31
138.	PA4078	2009-02-02	2012-01-01	2012-12-31
139.	PC1262	2009-02-17	2012-01-01	2012-12-31
140.	PC2637	2009-02-23	2012-01-01	2012-12-31
141.	PC2638	2009-02-23	2012-01-01	2012-12-31
142.	PC2641	2009-02-23	2012-01-01	2012-12-31
143.	PC2642	2009-02-23	2012-01-01	2012-12-31
144.	PC2639	2009-02-23	2012-01-01	2012-12-31
145.	PC2644	2009-02-23	2012-01-01	2012-12-31
146.	PC2645	2009-02-23	2012-01-01	2012-12-31
147.	PC2648	2009-02-23	2012-01-01	2012-12-31
148.	PC2649	2009-02-23	2012-01-01	2012-12-31
149.	PC2650	2009-02-23	2012-01-01	2012-12-31
150.	PC2646	2009-02-23	2012-01-01	2012-12-31
151.	PC2647	2009-02-23	2012-01-01	2012-12-31
152.	PC2651	2009-02-23	2012-01-01	2012-12-31
153.	PA6247	2009-02-23	2012-01-01	2012-12-31
154.	PA4122	2009-02-23	2012-01-01	2012-12-31
155.	PA6238	2009-02-23	2012-01-01	2012-12-31
156.	PC2655	2009-03-16	2012-01-01	2012-12-31
157.	PC2654	2009-03-16	2012-01-01	2012-12-31
158.	PC2653	2009-03-16	2012-01-01	2012-12-31
159.	PC2652	2009-03-16	2012-01-01	2012-12-31
160.	PC2656	2009-03-16	2012-01-01	2012-12-31
161.	PC2657	2009-03-16	2012-01-01	2012-12-31
162.	PC2658	2009-03-16	2012-01-01	2012-12-31
163.	PC2659	2009-03-16	2012-01-01	2012-12-31
164.	PC2662	2009-03-16	2012-01-01	2012-12-31
165.	PC2663	2009-03-16	2012-01-01	2012-12-31
166.	PC2660	2009-03-16	2012-01-01	2012-12-31
167.	PC2661	2009-03-16	2012-01-01	2012-12-31
168.	PC2665	2009-03-16	2012-01-01	2012-12-31
169.	PC1274	2009-03-26	2012-01-01	2012-12-31
170.	PC1269	2009-03-26	2012-01-01	2012-12-31
171.	PC1270	2009-03-26	2012-01-01	2012-11-27
172.	PC1273	2009-03-26	2012-01-01	2012-12-31
173.	PC1279	2009-03-26	2012-01-01	2012-12-03

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174.	PC1278	2009-03-26	2012-01-01	2012-12-31
175.	PC1277	2009-03-26	2012-01-01	2012-12-31
176.	PC1268	2009-03-26	2012-01-01	2012-08-27
177.	PC1282	2009-03-30	2012-01-01	2012-12-31
178.	AD9950	2009-04-16	2012-01-01	2012-12-31
179.	PC2674	2009-04-20	2012-01-01	2012-12-31
180.	PD8712	2009-04-20	2012-01-01	2012-12-31
181.	PC2679	2009-04-20	2012-01-01	2012-12-31
182.	PC2678	2009-04-20	2012-01-01	2012-12-31
183.	PC2672	2009-04-20	2012-01-01	2012-12-31
184.	PD8714	2009-04-20	2012-01-01	2012-12-31
185.	PC2677	2009-04-20	2012-01-01	2012-12-31
186.	PC2671	2009-04-20	2012-01-01	2012-12-31
187.	PD8711	2009-04-20	2012-01-01	2012-12-31
188.	PC2675	2009-04-20	2012-01-01	2012-12-31
189.	PC2673	2009-04-20	2012-01-01	2012-12-31
190.	PD8713	2009-04-20	2012-01-01	2012-12-31
191.	PC2666	2009-04-20	2012-01-01	2012-12-31
192.	PC2667	2009-04-20	2012-01-01	2012-12-31
193.	PA4079	2009-05-25	2012-01-01	2012-12-31
194.	PD8721	2009-05-25	2012-01-01	2012-12-31
195.	PD8720	2009-05-25	2012-01-01	2012-12-31
196.	PD8717	2009-05-25	2012-01-01	2012-12-31
197.	PD8719	2009-05-25	2012-01-01	2012-12-31
198.	PD8718	2009-05-25	2012-01-01	2012-12-31
199.	PD8723	2009-05-25	2012-01-01	2012-12-31
200.	PD8722	2009-05-25	2012-01-01	2012-12-31
201.	PD8725	2009-05-25	2012-01-01	2012-12-31
202.	PD8724	2009-05-25	2012-01-01	2012-12-31
203.	PD8726	2009-05-25	2012-01-01	2012-12-31
204.	PD8729	2009-05-25	2012-01-01	2012-12-31
205.	PD8715	2009-05-25	2012-01-01	2012-12-31
206.	PD8716	2009-05-25	2012-01-01	2012-12-31
207.	PD8730	2009-06-01	2012-01-01	2012-12-31
208.	PC2797	2009-06-01	2012-01-01	2012-12-31
209.	PA4695	2009-06-01	2012-01-01	2012-12-31
210.	PB7417	2009-06-01	2012-01-01	2012-12-31
211.	PA3572	2009-06-01	2012-01-01	2012-12-31
212.	PA6104	2009-06-01	2012-01-01	2012-12-31
213.	PC9747	2009-06-01	2012-01-01	2012-12-31
214.	PD8840	2009-06-01	2012-01-01	2012-12-31
215.	PD8830	2009-06-01	2012-01-01	2012-12-31
216.	PD8838	2009-06-01	2012-01-01	2012-12-31
217.	PA8998	2009-06-01	2012-01-01	2012-12-31
218.	PB5524	2009-06-01	2012-01-01	2012-12-31
219.	PC2799	2009-06-01	2012-01-01	2012-12-31
220.	PC7114	2009-06-01	2012-01-01	2012-12-31
221.	PD8833	2009-06-01	2012-01-01	2012-12-31
222.	PD8836	2009-06-01	2012-01-01	2012-12-31
223.	PD8842	2009-06-01	2012-01-01	2012-12-31
224.	A85304	2009-06-01	2012-01-01	2012-12-31
225.	PC2804	2009-06-01	2012-01-01	2012-12-31
226.	PD8841	2009-06-01	2012-01-01	2012-12-31

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227.	PD8837	2009-06-01	2012-01-01	2012-12-31
228.	PD8839	2009-06-01	2012-01-01	2012-12-31
229.	PD8835	2009-06-01	2012-01-01	2012-12-31
230.	PD8846	2009-06-01	2012-01-01	2012-12-31
231.	PD8843	2009-06-01	2012-01-01	2012-12-31
232.	PD8831	2009-06-01	2012-01-01	2012-12-31
233.	PC2798	2009-06-01	2012-01-01	2012-12-31
234.	PD8834	2009-06-01	2012-01-01	2012-12-31
235.	PD8832	2009-06-01	2012-01-01	2012-12-31
236.	PC1283	2009-06-11	2012-01-01	2012-12-31
237.	PD8870	2009-07-13	2012-01-01	2012-12-31
238.	PD8871	2009-07-13	2012-01-01	2012-12-31
239.	PD8865	2009-07-13	2012-01-01	2012-12-31
240.	PD8866	2009-07-13	2012-01-01	2012-12-31
241.	PD8867	2009-07-13	2012-01-01	2012-12-31
242.	PB8593	2009-07-13	2012-01-01	2012-04-02
243.	PD8868	2009-07-13	2012-01-01	2012-12-31
244.	PD8869	2009-07-13	2012-01-01	2012-12-31
245.	AG9966	2009-08-17	2012-01-01	2012-12-31
246.	PD8874	2009-09-21	2012-04-12	2012-12-31
247.	PD8877	2009-10-13	2012-01-01	2012-12-31
248.	PD8878	2009-10-19	2012-01-01	2012-12-31
249.	PD8879	2009-10-21	2012-05-31	2012-12-31
250.	PD8880	2009-10-21	2012-01-01	2012-12-31
251.	PD8884	2009-10-29	2012-01-01	2012-12-31
252.	PD8887	2009-10-29	2012-01-01	2012-12-31
253.	PD8886	2009-10-29	2012-01-01	2012-12-31
254.	PD8883	2009-10-29	2012-01-01	2012-12-31
255.	A86038	2009-10-29	2012-01-01	2012-12-31
256.	PD8885	2009-10-29	2012-01-01	2012-12-31
257.	PD8882	2009-10-29	2012-01-01	2012-12-31
258.	PD8849	2009-11-16	2012-01-01	2012-12-31
259.	AD9905	2010-01-11	2012-01-01	2012-12-31
260.	PD1190	2010-01-11	2012-01-01	2012-12-31
261.	PD8853	2010-01-11	2012-01-01	2012-12-31
262.	PD1194	2010-01-11	2012-01-01	2012-12-31
263.	PD1193	2010-01-11	2012-01-01	2012-12-31
264.	PD8855	2010-01-11	2012-01-01	2012-12-31
265.	PD8854	2010-01-11	2012-01-01	2012-12-31
266.	PD8860	2010-01-11	2012-01-01	2012-12-31
267.	PD8852	2010-01-11	2012-01-01	2012-12-31
268.	PD8857	2010-01-11	2012-01-01	2012-12-31
269.	PD1191	2010-01-11	2012-01-01	2012-12-31
270.	PD1192	2010-01-11	2012-01-01	2012-12-31
271.	PA9019	2010-01-11	2012-01-01	2012-12-31
272.	PD8859	2010-01-11	2012-01-01	2012-12-31
273.	PD1195	2010-01-11	2012-01-01	2012-12-31
274.	PD8856	2010-01-11	2012-01-01	2012-12-31
275.	D24335	2010-01-11	2012-01-01	2012-12-31
276.	PA3582	2010-01-11	2012-01-01	2012-12-31
277.	PD1200	2010-01-11	2012-01-01	2012-12-31
278.	PD1197	2010-01-11	2012-01-01	2012-12-31
279.	PD1201	2010-01-11	2012-01-01	2012-12-31

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280.	PD1199	2010-01-11	2012-01-01	2012-12-31
281.	PD1202	2010-01-11	2012-01-01	2012-12-31
282.	PC5463	2010-01-11	2012-01-01	2012-12-31
283.	PD1204	2010-01-11	2012-01-01	2012-12-31
284.	PD1203	2010-01-11	2012-01-01	2012-12-31
285.	PD1206	2010-01-11	2012-01-01	2012-12-31
286.	PD1207	2010-01-11	2012-01-01	2012-12-31
287.	A78556	2010-01-18	2012-05-31	2012-12-31
288.	PD8890	2010-01-18	2012-01-01	2012-12-31
289.	D13161	2010-01-18	2012-01-01	2012-12-31
290.	PD1198	2010-01-25	2012-01-01	2012-12-31
291.	PD1210	2010-01-25	2012-01-01	2012-12-31
292.	PA4126	2010-01-25	2012-01-01	2012-12-31
293.	PD1214	2010-01-25	2012-01-01	2012-12-31
294.	PD1217	2010-01-25	2012-01-01	2012-12-31
295.	PD8851	2010-01-25	2012-01-01	2012-12-31
296.	PD1209	2010-01-25	2012-01-01	2012-12-31
297.	PD1220	2010-01-25	2012-01-01	2012-12-31
298.	PD1216	2010-01-25	2012-01-01	2012-12-31
299.	PD1196	2010-01-25	2012-01-01	2012-12-31
300.	PD1218	2010-01-25	2012-01-01	2012-12-31
301.	PD1213	2010-01-25	2012-01-01	2012-12-31
302.	PD1219	2010-01-25	2012-01-01	2012-12-31
303.	PD1212	2010-01-25	2012-01-01	2012-12-31
304.	PD1211	2010-01-25	2012-01-01	2012-12-31
305.	PD1221	2010-01-25	2012-01-01	2012-12-31
306.	PD1226	2010-02-22	2012-01-01	2012-12-31
307.	PD1234	2010-02-22	2012-01-01	2012-12-31
308.	PD1225	2010-02-22	2012-01-01	2012-12-31
309.	PA8734	2010-02-22	2012-01-01	2012-12-31
310.	PD1224	2010-02-22	2012-01-01	2012-12-31
311.	PD1231	2010-02-22	2012-01-01	2012-12-31
312.	PD1228	2010-02-22	2012-01-01	2012-12-31
313.	PD1223	2010-02-22	2012-01-01	2012-12-31
314.	PD1233	2010-02-22	2012-01-01	2012-12-31
315.	PD1229	2010-02-22	2012-01-01	2012-12-31
316.	PD1236	2010-02-22	2012-01-01	2012-12-31
317.	PD1235	2010-02-22	2012-01-01	2012-12-31
318.	PD1231	2010-02-22	2012-01-01	2012-12-31
319.	PD1227	2010-02-22	2012-01-01	2012-12-31
320.	PD1222	2010-02-22	2012-01-01	2012-12-31
321.	PD1230	2010-02-22	2012-01-01	2012-12-31
322.	PD8895	2010-03-02	2012-01-01	2012-12-31
323.	PE8406	2010-03-08	2012-01-01	2012-12-31
324.	PD1243	2010-03-08	2012-01-01	2012-12-31
325.	PE8405	2010-03-08	2012-01-01	2012-12-31
326.	PD1240	2010-03-08	2012-01-01	2012-12-31
327.	PD1242	2010-03-08	2012-01-01	2012-12-31
328.	PE8412	2010-03-08	2012-01-01	2012-12-31
329.	PD1244	2010-03-08	2012-01-01	2012-12-31
330.	PE8407	2010-03-08	2012-01-01	2012-12-31
331.	PE8408	2010-03-08	2012-01-01	2012-09-02
332.	PD1237	2010-03-08	2012-01-01	2012-12-31

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333.	PD1241	2010-03-08	2012-01-01	2012-12-31
334.	PE8410	2010-03-08	2012-01-01	2012-12-31
335.	PD1238	2010-03-08	2012-01-01	2012-12-31
336.	PE8409	2010-03-08	2012-01-01	2012-12-31
337.	PE8411	2010-03-08	2012-01-01	2012-12-31
338.	PD1237	2010-03-08	2012-01-01	2012-12-31
339.	PE8419	2010-04-12	2012-01-01	2012-12-31
340.	PE8417	2010-04-12	2012-01-01	2012-12-31
341.	PE8416	2010-04-12	2012-01-01	2012-12-31
342.	PE8424	2010-04-12	2012-01-01	2012-12-31
343.	PA4118	2010-04-12	2012-01-01	2012-12-31
344.	PE8423	2010-04-12	2012-01-01	2012-12-31
345.	PE8415	2010-04-12	2012-01-01	2012-12-31
346.	PE8427	2010-04-12	2012-01-01	2012-12-31
347.	PA8742	2010-04-12	2012-01-01	2012-12-31
348.	PE8414	2010-04-12	2012-01-01	2012-12-31
349.	PE8420	2010-04-12	2012-01-01	2012-12-31
350.	PE8421	2010-04-12	2012-01-01	2012-12-31
351.	PE8425	2010-04-12	2012-01-01	2012-12-31
352.	PA7954	2010-04-12	2012-01-01	2012-12-31
353.	PE8426	2010-04-12	2012-01-01	2012-12-31
354.	PE8418	2010-04-12	2012-01-01	2012-12-31
355.	PC0432	2010-04-26	2012-01-01	2012-12-31
356.	D51472	2010-04-26	2012-01-01	2012-04-30
357.	PD8601	2010-04-26	2012-01-01	2012-12-31
358.	PD8899	2010-04-26	2012-01-01	2012-12-31
359.	PD8898	2010-04-26	2012-01-01	2012-12-31
360.	PA7691	2010-04-26	2012-01-01	2012-09-07
361.	PE8431	2010-05-03	2012-01-01	2012-12-31
362.	PE8428	2010-05-03	2012-01-01	2012-12-31
363.	PE8432	2010-05-03	2012-01-01	2012-12-31
364.	PE8429	2010-05-03	2012-01-01	2012-12-31
365.	PE8434	2010-05-03	2012-01-01	2012-04-23
366.	PE8434	2010-05-03	2012-08-30	2012-12-31
367.	PE8433	2010-05-03	2012-01-01	2012-12-31
368.	PE8435	2010-05-03	2012-01-01	2012-12-31
369.	PB1218	2010-05-03	2012-01-01	2012-12-31
370.	PE8413	2010-05-03	2012-01-01	2012-12-31
371.	PA0213	2010-05-03	2012-01-01	2012-12-31
372.	PE8430	2010-05-03	2012-01-01	2012-12-31
373.	AD9906	2010-05-31	2012-01-01	2012-12-31
374.	AD9907	2010-05-31	2012-01-01	2012-12-31
375.	PE8462	2010-05-31	2012-01-01	2012-12-31
376.	PE8463	2010-05-31	2012-01-01	2012-12-31
377.	PE8436	2010-05-31	2012-01-01	2012-12-31
378.	PE8456	2010-05-31	2012-01-01	2012-12-31
379.	PA6251	2010-05-31	2012-01-01	2012-12-31
380.	PE8457	2010-05-31	2012-01-01	2012-12-31
381.	PE8455	2010-05-31	2012-01-01	2012-12-31
382.	PE8460	2010-05-31	2012-01-01	2012-12-31
383.	PE8459	2010-05-31	2012-01-01	2012-12-31
384.	PE8461	2010-05-31	2012-01-01	2012-12-31
385.	PB2257	2010-05-31	2012-01-01	2012-12-31

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386.	PE8447	2010-05-31	2012-01-01	2012-12-31
387.	PE8443	2010-05-31	2012-01-01	2012-12-31
388.	PE8450	2010-05-31	2012-01-01	2012-12-31
389.	PE8440	2010-05-31	2012-01-01	2012-12-31
390.	PE9351	2010-05-31	2012-01-01	2012-12-31
391.	PE8452	2010-05-31	2012-01-01	2012-12-31
392.	PE8448	2010-05-31	2012-01-01	2012-12-31
393.	PE8449	2010-05-31	2012-01-01	2012-12-31
394.	PE8442	2010-05-31	2012-01-01	2012-12-31
395.	PE8441	2010-05-31	2012-01-01	2012-12-31
396.	PE8444	2010-05-31	2012-01-01	2012-12-31
397.	PE8453	2010-05-31	2012-01-01	2012-12-31
398.	PE8445	2010-05-31	2012-01-01	2012-12-31
399.	PE8451	2010-05-31	2012-01-01	2012-12-31
400.	PE8446	2010-05-31	2012-01-01	2012-12-31
401.	PE8454	2010-05-31	2012-01-01	2012-12-31
402.	PE8439	2010-05-31	2012-01-01	2012-12-31
403.	PA4684	2010-05-31	2012-01-01	2012-12-31
404.	PD8901	2010-06-07	2012-01-01	2012-12-31
405.	PA7871	2010-06-07	2012-01-01	2012-12-31
406.	PD8903	2010-06-14	2012-01-01	2012-12-31
407.	PC0861	2010-06-14	2012-01-01	2012-06-08
408.	PA4630	2010-06-14	2012-01-01	2012-12-31
409.	PA9197	2010-06-14	2012-01-01	2012-12-31
410.	PC7795	2010-06-14	2012-01-01	2012-12-31
411.	AD9915	2010-07-05	2012-01-01	2012-12-31
412.	AD9914	2010-07-05	2012-01-01	2012-12-31
413.	AD9913	2010-07-05	2012-01-01	2012-10-28
414.	PE8438	2010-07-05	2012-01-01	2012-12-31
415.	PB1845	2010-08-03	2012-03-29	2012-10-04
416.	PB1851	2010-08-16	2012-01-01	2012-12-31
417.	PF9066	2010-08-16	2012-01-01	2012-12-31
418.	PB1850	2010-08-16	2012-01-01	2012-12-31
419.	PF9071	2010-08-16	2012-01-01	2012-12-31
420.	PC7041	2010-08-16	2012-01-01	2012-12-31
421.	PF2888	2010-08-16	2012-01-01	2012-12-31
422.	PB1847	2010-08-16	2012-01-01	2012-12-31
423.	PC7616	2010-08-16	2012-01-01	2012-12-31
424.	PB1849	2010-08-16	2012-01-01	2012-12-31
425.	PF9072	2010-08-16	2012-01-01	2012-12-31
426.	PF9069	2010-08-16	2012-01-01	2012-12-31
427.	PD8905	2010-09-07	2012-01-01	2012-12-31
428.	PF9073	2010-09-13	2012-04-12	2012-12-31
429.	PF9093	2010-10-01	2012-04-12	2012-12-31
430.	PD8908	2010-10-04	2012-01-01	2012-12-31
431.	PD3343	2010-10-04	2012-01-01	2012-12-31
432.	PD8907	2010-10-04	2012-01-01	2012-12-31
433.	PD8911	2010-10-04	2012-01-01	2012-12-31
434.	PD8909	2010-10-04	2012-01-01	2012-12-31
435.	PD8910	2010-10-04	2012-01-01	2012-12-31
436.	PF9078	2010-10-05	2012-04-12	2012-12-31
437.	PF9080	2010-10-12	2012-04-12	2012-12-31
438.	PD3344	2010-10-19	2012-10-15	2012-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
439.	PD3345	2010-10-25	2012-01-01	2012-12-31
440.	PD3346	2010-10-25	2012-01-01	2012-12-31
441.	PD3347	2010-11-03	2012-01-01	2012-12-31
442.	PD3348	2010-11-03	2012-03-29	2012-12-31
443.	PD3354	2010-11-08	2012-01-01	2012-12-31
444.	PD3350	2010-11-08	2012-05-31	2012-12-31
445.	PF9082	2010-11-09	2012-04-12	2012-12-31
446.	PF9085	2010-11-09	2012-04-18	2012-12-31
447.	PD3355	2010-11-23	2012-05-31	2012-12-31
448.	PA3683	2011-01-10	2012-01-01	2012-12-31
449.	PF9090	2011-01-28	2012-04-04	2012-07-27
450.	PD3359	2011-03-10	2012-01-01	2012-12-31
451.	PD3361	2011-03-10	2012-01-01	2012-12-31
452.	PE8273	2011-03-10	2012-01-01	2012-12-31
453.	PC3365	2011-03-16	2012-03-29	2012-12-31
454.	PD3363	2011-03-16	2012-03-29	2012-12-31
455.	PD3364	2011-03-16	2012-03-29	2012-12-31
456.	PB5840	2011-03-17	2012-10-15	2012-12-31
457.	PE8707	2011-03-28	2012-01-01	2012-12-31
458.	PE8464	2011-03-28	2012-01-01	2012-12-31
459.	PE8465	2011-03-28	2012-01-01	2012-12-31
460.	PE8708	2011-03-28	2012-01-01	2012-12-31
461.	PE8710	2011-03-28	2012-01-01	2012-12-31
462.	PE8711	2011-03-28	2012-01-01	2012-12-31
463.	PE8713	2011-03-28	2012-01-01	2012-12-31
464.	PE8458	2011-03-28	2012-01-01	2012-12-31
465.	PE8709	2011-03-28	2012-01-01	2012-12-31
466.	PE8712	2011-03-28	2012-01-01	2012-12-31
467.	PE8716	2011-03-28	2012-01-01	2012-12-31
468.	PE8715	2011-03-28	2012-01-01	2012-12-31
469.	PE8743	2011-03-28	2012-01-01	2012-12-31
470.	PE8717	2011-03-28	2012-01-01	2012-12-31
471.	PE9718	2011-03-28	2012-01-01	2012-12-31
472.	PC3368	2011-04-12	2012-03-29	2012-12-31
473.	PD3367	2011-04-12	2012-03-29	2012-12-31
474.	PA8727	2011-04-18	2012-01-01	2012-03-21
475.	PA6230	2011-04-18	2012-01-01	2012-02-09
476.	PE8727	2011-05-02	2012-01-01	2012-12-31
477.	PE8722	2011-05-02	2012-01-01	2012-12-31
478.	PG4562	2011-05-02	2012-01-01	2012-12-31
479.	PG4564	2011-05-02	2012-01-01	2012-12-31
480.	PG4561	2011-05-02	2012-01-01	2012-12-31
481.	PE8721	2011-05-02	2012-01-01	2012-12-31
482.	PE8723	2011-05-02	2012-01-01	2012-12-31
483.	PE8725	2011-05-02	2012-01-01	2012-12-31
484.	PE8726	2011-05-02	2012-01-01	2012-12-31
485.	PG4563	2011-05-02	2012-01-01	2012-12-31
486.	PE8720	2011-05-02	2012-01-01	2012-12-31
487.	PG4566	2011-05-02	2012-01-01	2012-12-31
488.	PE8729	2011-05-02	2012-01-01	2012-12-31
489.	PE8719	2011-05-02	2012-01-01	2012-12-31
490.	PE8728	2011-05-02	2012-01-01	2012-12-31
491.	PE8724	2011-05-02	2012-01-01	2012-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
492.	PF9125	2011-05-30	2012-05-14	2012-08-31
493.	AJ8934	2011-05-30	2012-01-01	2012-12-31
494.	AJ8932	2011-05-30	2012-01-01	2012-12-31
495.	AJ8935	2011-05-30	2012-01-01	2012-12-31
496.	AJ8936	2011-05-30	2012-01-01	2012-12-31
497.	D13351	2011-05-30	2012-01-01	2012-12-31
498.	PG4569	2011-05-30	2012-01-01	2012-12-31
499.	PF3034	2011-05-30	2012-01-01	2012-12-31
500.	PG4568	2011-05-30	2012-01-01	2012-12-31
501.	PG4573	2011-05-30	2012-01-01	2012-12-31
502.	PG4570	2011-05-30	2012-01-01	2012-12-31
503.	PG4572	2011-05-30	2012-01-01	2012-12-31
504.	PB7400	2011-05-30	2012-01-01	2012-12-31
505.	PE8437	2011-05-30	2012-01-01	2012-12-31
506.	PG4574	2011-05-30	2012-06-04	2012-12-31
507.	PE8731	2011-05-30	2012-01-01	2012-12-31
508.	PA6597	2011-05-30	2012-01-01	2012-12-31
509.	PE8730	2011-05-30	2012-01-01	2012-12-31
510.	PG4571	2011-05-30	2012-01-01	2012-12-31
511.	PF2347	2011-07-14	2012-01-01	2012-12-31
512.	PC7603	2011-07-18	2012-01-01	2012-12-31
513.	PF9109	2011-11-03	2012-11-08	2012-12-31
514.	PF9102	2011-11-28	2012-04-12	2012-12-31
515.	PC7624	2012-01-30	2012-01-30	2012-12-31
516.	PG4580	2012-01-30	2012-01-30	2012-12-31
517.	PG4585	2012-01-30	2012-01-30	2012-12-31
518.	PG4583	2012-01-30	2012-01-30	2012-12-31
519.	PG4575	2012-01-30	2012-01-30	2012-12-31
520.	PG4584	2012-01-30	2012-01-30	2012-12-31
521.	PD5713	2012-01-30	2012-01-30	2012-12-31
522.	PE6763	2012-01-30	2012-01-30	2012-12-31
523.	PG4577	2012-01-30	2012-01-30	2012-12-31
524.	PG4579	2012-01-30	2012-01-30	2012-12-31
525.	PG4582	2012-01-30	2012-01-30	2012-12-31
526.	PG4581	2012-01-30	2012-01-30	2012-12-31
527.	PG4576	2012-01-30	2012-01-30	2012-12-31
528.	PG4578	2012-01-30	2012-01-30	2012-12-31
529.	PE6764	2012-01-30	2012-01-30	2012-12-31
530.	PG4567	2012-01-30	2012-01-30	2012-12-31
531.	101439A	2012-02-06	2012-02-06	2012-12-31
532.	PE6767	2012-02-06	2012-02-06	2012-12-31
533.	101449A	2012-02-06	2012-02-06	2012-12-31
534.	PE6782	2012-02-27	2012-02-27	2012-12-31
535.	PE6783	2012-02-27	2012-02-27	2012-12-31
536.	PE6779	2012-02-27	2012-02-27	2012-12-31
537.	PE6768	2012-02-27	2012-02-27	2012-12-31
538.	PE6775	2012-02-27	2012-02-27	2012-12-31
539.	PE6776	2012-02-27	2012-02-27	2012-12-31
540.	PE6778	2012-02-27	2012-02-27	2012-12-31
541.	PE6784	2012-02-27	2012-02-27	2012-12-31
542.	PE6677	2012-02-27	2012-02-27	2012-12-31
543.	PE6766	2012-02-27	2012-02-27	2012-12-31
544.	PE4038	2012-02-27	2012-02-27	2012-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
545.	PE6777	2012-02-27	2012-02-27	2012-12-31
546.	PE6765	2012-02-27	2012-02-27	2012-12-31
547.	PE6774	2012-02-27	2012-02-27	2012-12-31
548.	PE6781	2012-02-27	2012-02-27	2012-12-31
549.	PE6780	2012-02-27	2012-02-27	2012-12-31
550.	PE6773	2012-02-27	2012-02-27	2012-12-31
551.	PD3377	2012-03-29	2012-03-29	2012-06-28
552.	PD3378	2012-03-29	2012-03-29	2012-12-31
553.	PD3379	2012-03-29	2012-03-29	2012-12-31
554.	PD3384	2012-03-29	2012-03-29	2012-12-31
555.	PD3380	2012-03-29	2012-03-29	2012-12-31
556.	PE7852	2012-03-29	2012-03-29	2012-12-31
557.	PD3382	2012-03-29	2012-03-29	2012-12-31
558.	PD3383	2012-03-29	2012-03-29	2012-12-31
559.	PF9112	2012-04-12	2012-04-12	2012-12-31
560.	PF9113	2012-04-12	2012-04-12	2012-12-31
561.	PF9114	2012-04-12	2012-04-12	2012-12-31
562.	PF9115	2012-04-12	2012-04-12	2012-12-31
563.	PF9116	2012-04-12	2012-04-12	2012-12-31
564.	PF9117	2012-04-12	2012-04-12	2012-12-31
565.	PB6254	2012-04-12	2012-04-12	2012-12-31
566.	PF9124	2012-04-26	2012-04-26	2012-12-31
567.	PA6235	2012-04-26	2012-04-26	2012-09-07
568.	PF1568	2012-04-26	2012-04-30	2012-12-31
569.	PF9120	2012-04-26	2012-04-26	2012-12-31
570.	PC7606	2012-04-26	2012-04-26	2012-12-31
571.	PE1669	2012-04-26	2012-04-26	2012-12-31
572.	PF9127	2012-04-26	2012-04-30	2012-12-31
573.	PA6289	2012-04-26	2012-04-26	2012-04-26
574.	AQ1140	2012-05-28	2012-05-28	2012-12-31
575.	AQ1139	2012-05-28	2012-05-28	2012-12-31
576.	C25932	2012-05-28	2012-05-28	2012-12-31
577.	PE6792	2012-05-28	2012-05-28	2012-12-31
578.	PG4983	2012-05-28	2012-05-28	2012-12-31
579.	PE6794	2012-05-28	2012-05-28	2012-12-31
580.	PE6790	2012-05-28	2012-05-28	2012-12-31
581.	PE6793	2012-05-28	2012-05-28	2012-12-31
582.	PE6797	2012-05-28	2012-05-28	2012-12-31
583.	PE6786	2012-05-28	2012-05-28	2012-12-31
584.	PC7890	2012-05-28	2012-05-28	2012-12-31
585.	PC7288	2012-05-28	2012-05-28	2012-12-31
586.	PE6787	2012-05-28	2012-05-28	2012-12-31
587.	PE6788	2012-05-28	2012-05-28	2012-12-31
588.	PE6789	2012-05-28	2012-05-28	2012-12-31
589.	PE6796	2012-05-28	2012-05-28	2012-12-31
590.	PE6795	2012-05-28	2012-05-28	2012-12-31
591.	PD3389	2012-07-26	2012-07-26	2012-12-31
592.	PF5365	2012-08-23	2012-08-23	2012-12-31
593.	PE6952	2012-08-23	2012-04-23	2012-12-31
594.	PD3388	2012-08-23	2012-08-23	2012-12-31
595.	PD3387	2012-08-23	2012-08-23	2012-12-31
596.	PD3386	2012-08-23	2012-08-23	2012-12-31
597.	PC9315	2012-10-15	2012-10-15	2012-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
598.	PD3393	2012-10-15	2012-10-15	2012-12-31
599.	PD3395	2012-10-15	2012-10-15	2012-12-31
600.	PE6951	2012-10-15	2012-10-15	2012-12-31
601.	PD3392	2012-10-15	2012-10-15	2012-12-31
602.	PD3394	2012-10-15	2012-10-15	2012-12-31
603.	PD3391	2012-10-15	2012-10-15	2012-12-31
604.	PF9132	2012-11-08	2012-11-08	2012-12-31
605.	PF9133	2012-11-08	2012-11-08	2012-12-31
606.	PF9135	2012-11-08	2012-11-08	2012-12-31
607.	PF9136	2012-11-08	2012-11-08	2012-12-31
608.	PF9137	2012-11-08	2012-11-08	2012-12-31
609.	PF9138	2012-11-08	2012-11-08	2012-12-31
610.	PF9139	2012-11-08	2012-11-08	2012-12-31
611.	PF9140	2012-11-08	2012-11-08	2012-12-31

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

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.		21	21	574
2.		35	35	956
3.		35	35	956
4.		50	50	1,366
5.		50	50	1,366
6.		50	50	1,366
7.		50	50	1,366
8.		50	50	1,366
9.		50	50	1,366
10.		50	50	1,366
11.		50	50	1,366
12.		50	50	1,366
13.		50	50	1,366
14.		50	50	1,366
15.		50	50	1,366
16.		85	85	2,322
17.		85	85	2,322
18.		85	85	2,322
19.		91	91	2,486
20.		91	91	2,486
21.		91	91	2,486
22.		91	91	2,486
23.		91	91	2,486
24.		91	91	2,486
25.		91	91	2,486
26.		91	91	2,486
27.		91	91	2,486
28.		91	91	2,486
29.		91	91	2,486
30.		91	91	2,486
31.		91	91	2,486
32.		91	91	2,486
33.		91	91	2,486
34.		112	112	3,060
35.		112	112	3,060
36.		112	112	3,060
37.		112	112	3,060
38.		112	112	3,060
39.		112	112	3,060
40.		112	112	3,060
41.		112	112	3,060
42.		112	112	3,060
43.		112	112	3,060
44.		112	112	3,060
45.		112	112	3,060
46.		112	112	3,060
47.		112	112	3,060
48.		141	141	3,852
49.		141	141	3,852
50.		141	141	3,852
51.		141	141	3,852
52.		141	141	3,852

	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
53.		141	141	3,852
54.		141	141	3,852
55.		141	141	3,852
56.		141	141	3,852
57.		141	141	3,852
58.		141	141	3,852
59.		141	141	3,852
60.		141	141	3,852
61.		141	141	3,852
62.		141	141	3,852
63.		141	141	3,852
64.		86	86	2,350
65.		154	154	4,208
66.		154	154	4,208
67.		154	154	4,208
68.		154	154	4,208
69.		154	154	4,208
70.		154	154	4,208
71.		154	154	4,208
72.		154	154	4,208
73.		154	154	4,208
74.		154	154	4,208
75.		154	154	4,208
76.		154	154	4,208
77.		154	154	4,208
78.		154	154	4,208
79.		154	154	4,208
80.		154	154	4,208
81.		154	154	4,208
82.		154	154	4,208
83.		154	154	4,208
84.		154	154	4,208
85.		154	154	4,208
86.		154	154	4,208
87.		154	154	4,208
88.		154	154	4,208
89.		154	154	4,208
90.		163	163	4,454
91.		193	193	5,273
92.		220	220	6,011
93.		224	224	6,120
94.		187	187	5,109
95.		238	238	6,503
96.		48	48	1,311
97.		288	288	7,869
98.		288	288	7,869
99.		288	288	7,869
100.		297	297	8,115
101.		264	264	7,213
102.		297	297	8,115
103.		336	336	9,180
104.		336	336	9,180
105.		325	325	8,880

	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
106.		251	251	6,858
107.		336	336	9,180
108.		214	214	5,847
109.		366	366	10,000
110.		239	239	6,530
111.		67	67	1,831
112.		366	366	10,000
113.		366	366	10,000
114.		366	366	10,000
115.		366	366	10,000
116.		366	366	10,000
117.		366	366	10,000
118.		366	366	10,000
119.		366	366	10,000
120.		366	366	10,000
121.		366	366	10,000
122.		145	145	3,962
123.		366	366	10,000
124.		366	366	10,000
125.		366	366	10,000
126.		366	366	10,000
127.		366	366	10,000
128.		366	366	10,000
129.		366	366	10,000
130.		366	366	10,000
131.		366	366	10,000
132.		366	366	10,000
133.		366	366	10,000
134.		366	366	10,000
135.		366	366	10,000
136.		366	366	10,000
137.		366	366	10,000
138.		366	366	10,000
139.		366	366	10,000
140.		366	366	10,000
141.		366	366	10,000
142.		366	366	10,000
143.		366	366	10,000
144.		366	366	10,000
145.		366	366	10,000
146.		366	366	10,000
147.		366	366	10,000
148.		366	366	10,000
149.		366	366	10,000
150.		366	366	10,000
151.		366	366	10,000
152.		366	366	10,000
153.		366	366	10,000
154.		366	366	10,000
155.		366	366	10,000
156.		366	366	10,000
157.		366	366	10,000
158.		366	366	10,000

	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
159.		366	366	10,000
160.		366	366	10,000
161.		366	366	10,000
162.		366	366	10,000
163.		366	366	10,000
164.		366	366	10,000
165.		366	366	10,000
166.		366	366	10,000
167.		366	366	10,000
168.		366	366	10,000
169.		366	366	10,000
170.		366	366	10,000
171.		332	332	9,071
172.		366	366	10,000
173.		338	338	9,235
174.		366	366	10,000
175.		366	366	10,000
176.		240	240	6,557
177.		366	366	10,000
178.		366	366	10,000
179.		366	366	10,000
180.		366	366	10,000
181.		366	366	10,000
182.		366	366	10,000
183.		366	366	10,000
184.		366	366	10,000
185.		366	366	10,000
186.		366	366	10,000
187.		366	366	10,000
188.		366	366	10,000
189.		366	366	10,000
190.		366	366	10,000
191.		366	366	10,000
192.		366	366	10,000
193.		366	366	10,000
194.		366	366	10,000
195.		366	366	10,000
196.		366	366	10,000
197.		366	366	10,000
198.		366	366	10,000
199.		366	366	10,000
200.		366	366	10,000
201.		366	366	10,000
202.		366	366	10,000
203.		366	366	10,000
204.		366	366	10,000
205.		366	366	10,000
206.		366	366	10,000
207.		366	366	10,000
208.		366	366	10,000
209.		366	366	10,000
210.		366	366	10,000
211.		366	366	10,000

	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
212.		366	366	10,000
213.		366	366	10,000
214.		366	366	10,000
215.		366	366	10,000
216.		366	366	10,000
217.		366	366	10,000
218.		366	366	10,000
219.		366	366	10,000
220.		366	366	10,000
221.		366	366	10,000
222.		366	366	10,000
223.		366	366	10,000
224.		366	366	10,000
225.		366	366	10,000
226.		366	366	10,000
227.		366	366	10,000
228.		366	366	10,000
229.		366	366	10,000
230.		366	366	10,000
231.		366	366	10,000
232.		366	366	10,000
233.		366	366	10,000
234.		366	366	10,000
235.		366	366	10,000
236.		366	366	10,000
237.		366	366	10,000
238.		366	366	10,000
239.		366	366	10,000
240.		366	366	10,000
241.		366	366	10,000
242.		93	93	2,541
243.		366	366	10,000
244.		366	366	10,000
245.		366	366	10,000
246.		264	264	7,213
247.		366	366	10,000
248.		366	366	10,000
249.		215	215	5,874
250.		366	366	10,000
251.		366	366	10,000
252.		366	366	10,000
253.		366	366	10,000
254.		366	366	10,000
255.		366	366	10,000
256.		366	366	10,000
257.		366	366	10,000
258.		366	366	10,000
259.		366	366	10,000
260.		366	366	10,000
261.		366	366	10,000
262.		366	366	10,000
263.		366	366	10,000
264.		366	366	10,000

	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
265.		366	366	10,000
266.		366	366	10,000
267.		366	366	10,000
268.		366	366	10,000
269.		366	366	10,000
270.		366	366	10,000
271.		366	366	10,000
272.		366	366	10,000
273.		366	366	10,000
274.		366	366	10,000
275.		366	366	10,000
276.		366	366	10,000
277.		366	366	10,000
278.		366	366	10,000
279.		366	366	10,000
280.		366	366	10,000
281.		366	366	10,000
282.		366	366	10,000
283.		366	366	10,000
284.		366	366	10,000
285.		366	366	10,000
286.		366	366	10,000
287.		215	215	5,874
288.		366	366	10,000
289.		366	366	10,000
290.		366	366	10,000
291.		366	366	10,000
292.		366	366	10,000
293.		366	366	10,000
294.		366	366	10,000
295.		366	366	10,000
296.		366	366	10,000
297.		366	366	10,000
298.		366	366	10,000
299.		366	366	10,000
300.		366	366	10,000
301.		366	366	10,000
302.		366	366	10,000
303.		366	366	10,000
304.		366	366	10,000
305.		366	366	10,000
306.		366	366	10,000
307.		366	366	10,000
308.		366	366	10,000
309.		366	366	10,000
310.		366	366	10,000
311.		366	366	10,000
312.		366	366	10,000
313.		366	366	10,000
314.		366	366	10,000
315.		366	366	10,000
316.		366	366	10,000
317.		366	366	10,000

	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
318.		366	366	10,000
319.		366	366	10,000
320.		366	366	10,000
321.		366	366	10,000
322.		366	366	10,000
323.		366	366	10,000
324.		366	366	10,000
325.		366	366	10,000
326.		366	366	10,000
327.		366	366	10,000
328.		366	366	10,000
329.		366	366	10,000
330.		366	366	10,000
331.		246	246	6,721
332.		366	366	10,000
333.		366	366	10,000
334.		366	366	10,000
335.		366	366	10,000
336.		366	366	10,000
337.		366	366	10,000
338.		366	366	10,000
339.		366	366	10,000
340.		366	366	10,000
341.		366	366	10,000
342.		366	366	10,000
343.		366	366	10,000
344.		366	366	10,000
345.		366	366	10,000
346.		366	366	10,000
347.		366	366	10,000
348.		366	366	10,000
349.		366	366	10,000
350.		366	366	10,000
351.		366	366	10,000
352.		366	366	10,000
353.		366	366	10,000
354.		366	366	10,000
355.		366	366	10,000
356.		121	121	3,306
357.		366	366	10,000
358.		366	366	10,000
359.		366	366	10,000
360.		251	251	6,858
361.		366	366	10,000
362.		366	366	10,000
363.		366	366	10,000
364.		366	366	10,000
365.		113	113	3,087
366.		124	124	3,388
367.		366	366	10,000
368.		366	366	10,000
369.		366	366	10,000
370.		366	366	10,000

	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
371.		366	366	10,000
372.		366	366	10,000
373.		366	366	10,000
374.		366	366	10,000
375.		366	366	10,000
376.		366	366	10,000
377.		366	366	10,000
378.		366	366	10,000
379.		366	366	10,000
380.		366	366	10,000
381.		366	366	10,000
382.		366	366	10,000
383.		366	366	10,000
384.		366	366	10,000
385.		366	366	10,000
386.		366	366	10,000
387.		366	366	10,000
388.		366	366	10,000
389.		366	366	10,000
390.		366	366	10,000
391.		366	366	10,000
392.		366	366	10,000
393.		366	366	10,000
394.		366	366	10,000
395.		366	366	10,000
396.		366	366	10,000
397.		366	366	10,000
398.		366	366	10,000
399.		366	366	10,000
400.		366	366	10,000
401.		366	366	10,000
402.		366	366	10,000
403.		366	366	10,000
404.		366	366	10,000
405.		366	366	10,000
406.		366	366	10,000
407.		160	160	4,372
408.		366	366	10,000
409.		366	366	10,000
410.		366	366	10,000
411.		366	366	10,000
412.		366	366	10,000
413.		302	302	8,251
414.		366	366	10,000
415.		190	190	5,191
416.		366	366	10,000
417.		366	366	10,000
418.		366	366	10,000
419.		366	366	10,000
420.		366	366	10,000
421.		366	366	10,000
422.		366	366	10,000
423.		366	366	10,000

	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
424.		366	366	10,000
425.		366	366	10,000
426.		366	366	10,000
427.		366	366	10,000
428.		264	264	7,213
429.		264	264	7,213
430.		366	366	10,000
431.		366	366	10,000
432.		366	366	10,000
433.		366	366	10,000
434.		366	366	10,000
435.		366	366	10,000
436.		264	264	7,213
437.		264	264	7,213
438.		78	78	2,131
439.		366	366	10,000
440.		366	366	10,000
441.		366	366	10,000
442.		278	278	7,596
443.		366	366	10,000
444.		215	215	5,874
445.		264	264	7,213
446.		258	258	7,049
447.		215	215	5,874
448.		366	366	10,000
449.		115	115	3,142
450.		366	366	10,000
451.		366	366	10,000
452.		366	366	10,000
453.		278	278	7,596
454.		278	278	7,596
455.		278	278	7,596
456.		78	78	2,131
457.		366	366	10,000
458.		366	366	10,000
459.		366	366	10,000
460.		366	366	10,000
461.		366	366	10,000
462.		366	366	10,000
463.		366	366	10,000
464.		366	366	10,000
465.		366	366	10,000
466.		366	366	10,000
467.		366	366	10,000
468.		366	366	10,000
469.		366	366	10,000
470.		366	366	10,000
471.		366	366	10,000
472.		278	278	7,596
473.		278	278	7,596
474.		81	81	2,213
475.		40	40	1,093
476.		366	366	10,000

	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
477.		366	366	10,000
478.		366	366	10,000
479.		366	366	10,000
480.		366	366	10,000
481.		366	366	10,000
482.		366	366	10,000
483.		366	366	10,000
484.		366	366	10,000
485.		366	366	10,000
486.		366	366	10,000
487.		366	366	10,000
488.		366	366	10,000
489.		366	366	10,000
490.		366	366	10,000
491.		366	366	10,000
492.		110	110	3,005
493.		366	366	10,000
494.		366	366	10,000
495.		366	366	10,000
496.		366	366	10,000
497.		366	366	10,000
498.		366	366	10,000
499.		366	366	10,000
500.		366	366	10,000
501.		366	366	10,000
502.		366	366	10,000
503.		366	366	10,000
504.		366	366	10,000
505.		366	366	10,000
506.		210	210	5,738
507.		366	366	10,000
508.		366	366	10,000
509.		366	366	10,000
510.		366	366	10,000
511.		366	366	10,000
512.		366	366	10,000
513.		54	54	1,475
514.		264	264	7,213
515.		337	337	9,208
516.		337	337	9,208
517.		337	337	9,208
518.		337	337	9,208
519.		337	337	9,208
520.		337	337	9,208
521.		337	337	9,208
522.		337	337	9,208
523.		337	337	9,208
524.		337	337	9,208
525.		337	337	9,208
526.		337	337	9,208
527.		337	337	9,208
528.		337	337	9,208
529.		337	337	9,208

	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
530.		337	337	9,208
531.		330	330	9,016
532.		330	330	9,016
533.		330	330	9,016
534.		309	309	8,443
535.		309	309	8,443
536.		309	309	8,443
537.		309	309	8,443
538.		309	309	8,443
539.		309	309	8,443
540.		309	309	8,443
541.		309	309	8,443
542.		309	309	8,443
543.		309	309	8,443
544.		309	309	8,443
545.		309	309	8,443
546.		309	309	8,443
547.		309	309	8,443
548.		309	309	8,443
549.		309	309	8,443
550.		309	309	8,443
551.		92	92	2,514
552.		278	278	7,596
553.		278	278	7,596
554.		278	278	7,596
555.		278	278	7,596
556.		278	278	7,596
557.		278	278	7,596
558.		278	278	7,596
559.		264	264	7,213
560.		264	264	7,213
561.		264	264	7,213
562.		264	264	7,213
563.		264	264	7,213
564.		264	264	7,213
565.		264	264	7,213
566.		250	250	6,831
567.		135	135	3,689
568.		246	246	6,721
569.		250	250	6,831
570.		250	250	6,831
571.		250	250	6,831
572.		246	246	6,721
573.		1	1	27
574.		218	218	5,956
575.		218	218	5,956
576.		218	218	5,956
577.		218	218	5,956
578.		218	218	5,956
579.		218	218	5,956
580.		218	218	5,956
581.		218	218	5,956
582.		218	218	5,956

	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
583.		218	218	5,956
584.		218	218	5,956
585.		218	218	5,956
586.		218	218	5,956
587.		218	218	5,956
588.		218	218	5,956
589.		218	218	5,956
590.		218	218	5,956
591.		159	159	4,344
592.		131	131	3,579
593.		253	253	6,913
594.		131	131	3,579
595.		131	131	3,579
596.		131	131	3,579
597.		78	78	2,131
598.		78	78	2,131
599.		78	78	2,131
600.		78	78	2,131
601.		78	78	2,131
602.		78	78	2,131
603.		78	78	2,131
604.		54	54	1,475
605.		54	54	1,475
606.		54	54	1,475
607.		54	54	1,475
608.		54	54	1,475
609.		54	54	1,475
610.		54	54	1,475
611.		54	54	1,475

	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.		61,509	61,509	21,528
2.		67,825	67,825	23,739
3.		72,883	72,883	25,509
4.		102,991	102,991	36,047
5.		117,635	117,635	41,172
6.		108,964	108,964	38,137
7.		113,905	113,905	39,867
8.		141,698	141,698	49,594
9.		131,034	131,034	45,862
10.		105,248	105,248	36,837
11.		118,207	118,207	41,372
12.		109,861	109,861	38,451
13.		146,156	146,156	51,155
14.		116,160	116,160	40,656
15.		109,668	109,668	38,384
16.		61,630	61,630	21,571
17.		60,993	60,993	21,348

	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
18.		59,940	59,940	20,979
19.		127,265	127,265	44,543
20.		92,817	92,817	32,486
21.		99,851	99,851	34,948
22.		107,699	107,699	37,695
23.		101,396	101,396	35,489
24.		127,260	127,260	44,541
25.		98,659	98,659	34,531
26.		119,600	119,600	41,860
27.		99,065	99,065	34,673
28.		106,478	106,478	37,267
29.		105,352	105,352	36,873
30.		103,115	103,115	36,090
31.		107,083	107,083	37,479
32.		101,154	101,154	35,404
33.		103,485	103,485	36,220
34.		104,354	104,354	36,524
35.		104,942	104,942	36,730
36.		101,343	101,343	35,470
37.		105,094	105,094	36,783
38.		96,468	96,468	33,764
39.		107,391	107,391	37,587
40.		112,778	112,778	39,472
41.		105,693	105,693	36,993
42.		94,225	94,225	32,979
43.		119,915	119,915	41,970
44.		87,115	87,115	30,490
45.		106,882	106,882	37,409
46.		124,895	124,895	43,713
47.		107,707	107,707	37,697
48.		107,181	107,181	37,513
49.		90,405	90,405	31,642
50.		88,900	88,900	31,115
51.		84,779	84,779	29,673
52.		127,965	127,965	44,788
53.		113,607	113,607	39,762
54.		75,913	75,913	26,570
55.		87,518	87,518	30,631
56.		75,582	75,582	26,454
57.		96,557	96,557	33,795
58.		84,806	84,806	29,682
59.		75,630	75,630	26,471
60.		91,394	91,394	31,988
61.		89,228	89,228	31,230
62.		119,509	119,509	41,828
63.		111,875	111,875	39,156
64.		69,861	69,861	24,451
65.		113,797	113,797	39,829
66.		80,468	80,468	28,164
67.		110,858	110,858	38,800
68.		89,310	89,310	31,259
69.		81,204	81,204	28,421
70.		83,585	83,585	29,255

	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
71.		75,298	75,298	26,354
72.		118,154	118,154	41,354
73.		118,417	118,417	41,446
74.		40,205	40,205	14,072
75.		91,202	91,202	31,921
76.		82,215	82,215	28,775
77.		84,485	84,485	29,570
78.		77,836	77,836	27,243
79.		85,372	85,372	29,880
80.		76,583	76,583	26,804
81.		94,375	94,375	33,031
82.		71,365	71,365	24,978
83.		98,934	98,934	34,627
84.		96,667	96,667	33,833
85.		75,927	75,927	26,574
86.		95,816	95,816	33,536
87.		60,888	60,888	21,311
88.		84,110	84,110	29,439
89.		73,888	73,888	25,861
90.		94,123	94,123	32,943
91.		75,181	75,181	26,313
92.		84,918	84,918	29,721
93.		60,276	60,276	21,097
94.		78,413	78,413	27,445
95.		93,746	93,746	32,811
96.		112,217	112,217	39,276
97.		54,306	54,306	19,007
98.		54,252	54,252	18,988
99.		51,334	51,334	17,967
100.		73,689	73,689	25,791
101.		70,873	70,873	24,806
102.		82,232	82,232	28,781
103.		52,064	52,064	18,222
104.		56,804	56,804	19,881
105.		65,610	65,610	22,964
106.		41,103	41,103	14,386
107.		70,635	70,635	24,722
108.		67,350	67,350	23,573
109.		63,812	63,812	22,334
110.		58,885	58,885	20,610
111.		58,885	58,885	20,610
112.		83,523	83,523	29,233
113.		96,394	96,394	33,738
114.		63,947	63,947	22,381
115.		65,436	65,436	22,903
116.		81,971	81,971	28,690
117.		69,516	69,516	24,331
118.		50,072	50,072	17,525
119.		87,278	87,278	30,547
120.		59,827	59,827	20,939
121.		53,847	53,847	18,846
122.		77,794	77,794	27,228
123.		94,330	94,330	33,016

	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
124.		95,961	95,961	33,586
125.		79,475	79,475	27,816
126.		77,694	77,694	27,193
127.		73,108	73,108	25,588
128.		76,246	76,246	26,686
129.		144,952	144,952	50,733
130.		76,459	76,459	26,761
131.		82,223	82,223	28,778
132.		78,799	78,799	27,580
133.		76,028	76,028	26,610
134.		84,598	84,598	29,609
135.		77,175	77,175	27,011
136.		108,247	108,247	37,886
137.		143,498	143,498	50,224
138.		98,472	98,472	34,465
139.		36,673	36,673	12,836
140.		107,002	107,002	37,451
141.		87,844	87,844	30,745
142.		79,337	79,337	27,768
143.		81,407	81,407	28,492
144.		74,095	74,095	25,933
145.		104,685	104,685	36,640
146.		75,667	75,667	26,483
147.		70,223	70,223	24,578
148.		89,872	89,872	31,455
149.		81,945	81,945	28,681
150.		89,183	89,183	31,214
151.		86,482	86,482	30,269
152.		75,900	75,900	26,565
153.		75,911	75,911	26,569
154.		95,175	95,175	33,311
155.		77,083	77,083	26,979
156.		80,136	80,136	28,048
157.		85,639	85,639	29,974
158.		82,272	82,272	28,795
159.		89,309	89,309	31,258
160.		88,425	88,425	30,949
161.		89,022	89,022	31,158
162.		108,860	108,860	38,101
163.		78,267	78,267	27,393
164.		83,623	83,623	29,268
165.		84,105	84,105	29,437
166.		78,521	78,521	27,482
167.		73,318	73,318	25,661
168.		87,300	87,300	30,555
169.		73,818	73,818	25,836
170.		74,584	74,584	26,104
171.		85,960	85,960	30,086
172.		66,738	66,738	23,358
173.		77,503	77,503	27,126
174.		82,038	82,038	28,713
175.		71,608	71,608	25,063
176.		75,764	75,764	26,517

	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
177.		46,131	46,131	16,146
178.		86,828	86,828	30,390
179.		68,140	68,140	23,849
180.		76,420	76,420	26,747
181.		78,795	78,795	27,578
182.		74,859	74,859	26,201
183.		79,914	79,914	27,970
184.		82,923	82,923	29,023
185.		88,580	88,580	31,003
186.		89,084	89,084	31,179
187.		78,727	78,727	27,554
188.		81,802	81,802	28,631
189.		96,146	96,146	33,651
190.		66,849	66,849	23,397
191.		82,488	82,488	28,871
192.		75,697	75,697	26,494
193.		110,231	110,231	38,581
194.		82,616	82,616	28,916
195.		71,559	71,559	25,046
196.		75,391	75,391	26,387
197.		83,779	83,779	29,323
198.		71,999	71,999	25,200
199.		72,408	72,408	25,343
200.		71,704	71,704	25,096
201.		69,317	69,317	24,261
202.		75,324	75,324	26,363
203.		84,024	84,024	29,408
204.		79,322	79,322	27,763
205.		104,930	104,930	36,726
206.		71,373	71,373	24,981
207.		56,629	56,629	19,820
208.		75,895	75,895	26,563
209.		88,396	88,396	30,939
210.		73,777	73,777	25,822
211.		95,609	95,609	33,463
212.		78,334	78,334	27,417
213.		66,748	66,748	23,362
214.		42,753	42,753	14,964
215.		50,809	50,809	17,783
216.		62,164	62,164	21,757
217.		69,175	69,175	24,211
218.		112,440	112,440	39,354
219.		71,920	71,920	25,172
220.		75,828	75,828	26,540
221.		60,669	60,669	21,234
222.		86,108	86,108	30,138
223.		65,473	65,473	22,916
224.		101,648	101,648	35,577
225.		76,728	76,728	26,855
226.		60,576	60,576	21,202
227.		77,916	77,916	27,271
228.		67,406	67,406	23,592
229.		68,402	68,402	23,941

	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
230.		87,689	87,689	30,691
231.		54,096	54,096	18,934
232.		56,149	56,149	19,652
233.		64,318	64,318	22,511
234.		53,437	53,437	18,703
235.		46,052	46,052	16,118
236.		50,698	50,698	17,744
237.		70,964	70,964	24,837
238.		52,323	52,323	18,313
239.		56,493	56,493	19,773
240.		43,191	43,191	15,117
241.		60,744	60,744	21,260
242.		68,084	68,084	23,829
243.		50,178	50,178	17,562
244.		45,868	45,868	16,054
245.		45,703	45,703	15,996
246.		28,435	28,435	9,952
247.		41,744	41,744	14,610
248.		51,532	51,532	18,036
249.		38,410	38,410	13,444
250.		57,172	57,172	20,010
251.		45,611	45,611	15,964
252.		49,728	49,728	17,405
253.		50,524	50,524	17,683
254.		56,753	56,753	19,864
255.		70,626	70,626	24,719
256.		50,271	50,271	17,595
257.		50,247	50,247	17,586
258.		85,949	85,949	30,082
259.		62,902	62,902	22,016
260.		69,765	69,765	24,418
261.		73,622	73,622	25,768
262.		70,901	70,901	24,815
263.		71,658	71,658	25,080
264.		66,146	66,146	23,151
265.		66,888	66,888	23,411
266.		83,677	83,677	29,287
267.		64,821	64,821	22,687
268.		70,052	70,052	24,518
269.		72,776	72,776	25,472
270.		78,112	78,112	27,339
271.		75,825	75,825	26,539
272.		57,540	57,540	20,139
273.		43,178	43,178	15,112
274.		69,730	69,730	24,406
275.		54,857	54,857	19,200
276.		50,139	50,139	17,549
277.		75,172	75,172	26,310
278.		59,213	59,213	20,725
279.		81,370	81,370	28,480
280.		54,855	54,855	19,199
281.		60,463	60,463	21,162
282.		68,520	68,520	23,982

	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
283.		55,267	55,267	19,343
284.		75,729	75,729	26,505
285.		49,752	49,752	17,413
286.		54,948	54,948	19,232
287.		43,190	43,190	15,117
288.		41,919	41,919	14,672
289.		67,851	67,851	23,748
290.		80,030	80,030	28,011
291.		76,282	76,282	26,699
292.		71,117	71,117	24,891
293.		72,747	72,747	25,461
294.		70,179	70,179	24,563
295.		71,063	71,063	24,872
296.		66,316	66,316	23,211
297.		64,949	64,949	22,732
298.		78,992	78,992	27,647
299.		67,326	67,326	23,564
300.		69,164	69,164	24,207
301.		72,628	72,628	25,420
302.		72,014	72,014	25,205
303.		80,187	80,187	28,065
304.		64,573	64,573	22,601
305.		280	280	98
306.		65,204	65,204	22,821
307.		66,909	66,909	23,418
308.		69,873	69,873	24,456
309.		72,411	72,411	25,344
310.		57,520	57,520	20,132
311.		59,017	59,017	20,656
312.		68,971	68,971	24,140
313.		65,349	65,349	22,872
314.		74,010	74,010	25,904
315.		63,668	63,668	22,284
316.		61,035	61,035	21,362
317.		65,699	65,699	22,995
318.		64,459	64,459	22,561
319.		69,856	69,856	24,450
320.		65,814	65,814	23,035
321.		58,195	58,195	20,368
322.		70,246	70,246	24,586
323.		65,159	65,159	22,806
324.		65,136	65,136	22,798
325.		71,701	71,701	25,095
326.		59,259	59,259	20,741
327.		67,126	67,126	23,494
328.		77,441	77,441	27,104
329.		67,815	67,815	23,735
330.		75,057	75,057	26,270
331.		60,792	60,792	21,277
332.		69,320	69,320	24,262
333.		67,159	67,159	23,506
334.		72,766	72,766	25,468
335.		84,330	84,330	29,516

	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
336.		62,160	62,160	21,756
337.		62,681	62,681	21,938
338.		100,457	100,457	35,160
339.		63,788	63,788	22,326
340.		68,921	68,921	24,122
341.		64,856	64,856	22,700
342.		62,393	62,393	21,838
343.		88,498	88,498	30,974
344.		78,209	78,209	27,373
345.		83,220	83,220	29,127
346.		63,943	63,943	22,380
347.		67,674	67,674	23,686
348.		72,803	72,803	25,481
349.		62,722	62,722	21,953
350.		65,357	65,357	22,875
351.		68,368	68,368	23,929
352.		67,019	67,019	23,457
353.		66,507	66,507	23,277
354.		21,715	21,715	7,600
355.		60,774	60,774	21,271
356.		95,107	95,107	33,287
357.		43,769	43,769	15,319
358.		53,131	53,131	18,596
359.		47,746	47,746	16,711
360.		80,389	80,389	28,136
361.		59,078	59,078	20,677
362.		66,477	66,477	23,267
363.		84,616	84,616	29,616
364.		68,019	68,019	23,807
365.		75,934	75,934	26,577
366.		75,934	75,934	26,577
367.		66,714	66,714	23,350
368.		65,930	65,930	23,076
369.		112,490	112,490	39,372
370.		63,828	63,828	22,340
371.		79,258	79,258	27,740
372.		63,412	63,412	22,194
373.		57,152	57,152	20,003
374.		107,052	107,052	37,468
375.		64,369	64,369	22,529
376.		63,061	63,061	22,071
377.		65,703	65,703	22,996
378.		87,204	87,204	30,521
379.		65,422	65,422	22,898
380.		49,656	49,656	17,380
381.		57,141	57,141	19,999
382.		67,420	67,420	23,597
383.		71,616	71,616	25,066
384.		61,088	61,088	21,381
385.		92,832	92,832	32,491
386.		61,133	61,133	21,397
387.		64,697	64,697	22,644
388.		68,505	68,505	23,977

	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
389.		66,050	66,050	23,118
390.		83,762	83,762	29,317
391.		79,862	79,862	27,952
392.		51,527	51,527	18,034
393.		63,172	63,172	22,110
394.		51,821	51,821	18,137
395.		50,125	50,125	17,544
396.		57,613	57,613	20,165
397.		70,963	70,963	24,837
398.		46,279	46,279	16,198
399.		54,023	54,023	18,908
400.		54,283	54,283	18,999
401.		65,135	65,135	22,797
402.		53,160	53,160	18,606
403.		55,266	55,266	19,343
404.		47,022	47,022	16,458
405.		52,229	52,229	18,280
406.		63,019	63,019	22,057
407.		89,611	89,611	31,364
408.		76,618	76,618	26,816
409.		65,985	65,985	23,095
410.		52,961	52,961	18,536
411.		67,569	67,569	23,649
412.		67,151	67,151	23,503
413.		66,179	66,179	23,163
414.		78,732	78,732	27,556
415.		20,978	20,978	7,342
416.		66,764	66,764	23,367
417.		76,138	76,138	26,648
418.		51,716	51,716	18,101
419.		73,303	73,303	25,656
420.		61,587	61,587	21,555
421.		89,012	89,012	31,154
422.		9,234	9,234	3,232
423.		56,776	56,776	19,872
424.		67,980	67,980	23,793
425.		57,707	57,707	20,197
426.		66,579	66,579	23,303
427.		52,721	52,721	18,452
428.		44,489	44,489	15,571
429.		45,588	45,588	15,956
430.		43,918	43,918	15,371
431.		52,374	52,374	18,331
432.		55,377	55,377	19,382
433.		46,534	46,534	16,287
434.		59,926	59,926	20,974
435.		54,847	54,847	19,196
436.		42,193	42,193	14,768
437.		45,545	45,545	15,941
438.		8,307	8,307	2,907
439.		60,854	60,854	21,299
440.		54,128	54,128	18,945
441.		20,513	20,513	7,180

	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
442.		25,772	25,772	9,020
443.		27,683	27,683	9,689
444.		17,456	17,456	6,110
445.		44,243	44,243	15,485
446.		41,895	41,895	14,663
447.		35,668	35,668	12,484
448.		43,738	43,738	15,308
449.		18,901	18,901	6,615
450.		61,817	61,817	21,636
451.		36,971	36,971	12,940
452.		43,042	43,042	15,065
453.		28,161	28,161	9,856
454.		35,775	35,775	12,521
455.		20,978	20,978	7,342
456.		11,918	11,918	4,171
457.		56,169	56,169	19,659
458.		46,218	46,218	16,176
459.		68,437	68,437	23,953
460.		66,984	66,984	23,444
461.		58,216	58,216	20,376
462.		75,003	75,003	26,251
463.		64,900	64,900	22,715
464.		58,362	58,362	20,427
465.		63,865	63,865	22,353
466.		54,663	54,663	19,132
467.		59,554	59,554	20,844
468.		50,391	50,391	17,637
469.		66,270	66,270	23,195
470.		67,159	67,159	23,506
471.		55,419	55,419	19,397
472.		20,570	20,570	7,200
473.		23,111	23,111	8,089
474.		66,456	66,456	23,260
475.		4,896	4,896	1,714
476.		64,229	64,229	22,480
477.		61,829	61,829	21,640
478.		67,604	67,604	23,661
479.		56,608	56,608	19,813
480.		58,575	58,575	20,501
481.		59,294	59,294	20,753
482.		56,960	56,960	19,936
483.		62,796	62,796	21,979
484.		66,351	66,351	23,223
485.		63,274	63,274	22,146
486.		64,073	64,073	22,426
487.		56,822	56,822	19,888
488.		56,805	56,805	19,882
489.		59,995	59,995	20,998
490.		56,751	56,751	19,863
491.		38,975	38,975	13,641
492.		16,682	16,682	5,839
493.		49,033	49,033	17,162
494.		54,676	54,676	19,137

	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
495.		44,490	44,490	15,572
496.		61,018	61,018	21,356
497.		44,463	44,463	15,562
498.		56,084	56,084	19,629
499.		57,396	57,396	20,089
500.		55,559	55,559	19,446
501.		45,165	45,165	15,808
502.		64,467	64,467	22,563
503.		48,646	48,646	17,026
504.		61,982	61,982	21,694
505.		42,318	42,318	14,811
506.		60,600	60,600	21,210
507.		55,449	55,449	19,407
508.		78,302	78,302	27,406
509.		58,614	58,614	20,515
510.		41,285	41,285	14,450
511.		39,233	39,233	13,732
512.		23,685	23,685	8,290
513.		5,976	5,976	2,092
514.		35,130	35,130	12,296
515.		51,069	51,069	17,874
516.		45,167	45,167	15,808
517.		51,229	51,229	17,930
518.		53,380	53,380	18,683
519.		45,103	45,103	15,786
520.		51,227	51,227	17,929
521.		55,572	55,572	19,450
522.		42,557	42,557	14,895
523.		46,024	46,024	16,108
524.		50,056	50,056	17,520
525.		33,122	33,122	11,593
526.		46,252	46,252	16,188
527.		58,173	58,173	20,361
528.		47,930	47,930	16,776
529.		43,814	43,814	15,335
530.		43,057	43,057	15,070
531.		50,182	50,182	17,564
532.		39,030	39,030	13,661
533.		47,851	47,851	16,748
534.		45,288	45,288	15,851
535.		52,788	52,788	18,476
536.		42,726	42,726	14,954
537.		66,926	66,926	23,424
538.		45,475	45,475	15,916
539.		45,186	45,186	15,815
540.		41,307	41,307	14,457
541.		34,123	34,123	11,943
542.		46,834	46,834	16,392
543.		46,658	46,658	16,330
544.		41,456	41,456	14,510
545.		41,505	41,505	14,527
546.		42,781	42,781	14,973
547.		52,579	52,579	18,403

	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
548.		39,599	39,599	13,860
549.		44,796	44,796	15,679
550.		43,603	43,603	15,261
551.		9,098	9,098	3,184
552.		30,993	30,993	10,848
553.		31,603	31,603	11,061
554.		32,211	32,211	11,274
555.		33,680	33,680	11,788
556.		22,330	22,330	7,816
557.		28,436	28,436	9,953
558.		30,127	30,127	10,544
559.		31,827	31,827	11,139
560.		51,467	51,467	18,013
561.		49,547	49,547	17,341
562.		30,041	30,041	10,514
563.		30,270	30,270	10,595
564.		35,491	35,491	12,422
565.		38,085	38,085	13,330
566.		35,914	35,914	12,570
567.		27,283	27,283	9,549
568.		41,219	41,219	14,427
569.		36,066	36,066	12,623
570.		45,832	45,832	16,041
571.		35,188	35,188	12,316
572.		37,107	37,107	12,987
573.		78,330	78,330	27,416
574.		24,917	24,917	8,721
575.		22,857	22,857	8,000
576.		21,860	21,860	7,651
577.		31,465	31,465	11,013
578.		38,149	38,149	13,352
579.		49,404	49,404	17,291
580.		34,190	34,190	11,967
581.		53,737	53,737	18,808
582.		35,821	35,821	12,537
583.		33,869	33,869	11,854
584.		29,535	29,535	10,337
585.		41,231	41,231	14,431
586.		44,022	44,022	15,408
587.		29,511	29,511	10,329
588.		51,117	51,117	17,891
589.		27,923	27,923	9,773
590.		29,626	29,626	10,369
591.		15,332	15,332	5,366
592.		16,248	16,248	5,687
593.		10,905	10,905	3,817
594.		12,372	12,372	4,330
595.		15,478	15,478	5,417
596.		15,331	15,331	5,366
597.		11,189	11,189	3,916
598.		8,009	8,009	2,803
599.		5,822	5,822	2,038
600.		6,816	6,816	2,386

	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
601.		8,209	8,209	2,873
602.		6,686	6,686	2,340
603.		7,562	7,562	2,647
604.		5,421	5,421	1,897
605.		6,150	6,150	2,153
606.		5,608	5,608	1,963
607.		6,150	6,150	2,153
608.		4,698	4,698	1,644
609.		5,815	5,815	2,035
610.		5,172	5,172	1,810
611.		5,793	5,793	2,028

	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.	574		574
2.	956		956
3.	956		956
4.	1,366		1,366
5.	1,366		1,366
6.	1,366		1,366
7.	1,366		1,366
8.	1,366		1,366
9.	1,366		1,366
10.	1,366		1,366
11.	1,366		1,366
12.	1,366		1,366
13.	1,366		1,366
14.	1,366		1,366
15.	1,366		1,366
16.	2,322		2,322
17.	2,322		2,322
18.	2,322		2,322
19.	2,486		2,486
20.	2,486		2,486
21.	2,486		2,486
22.	2,486		2,486
23.	2,486		2,486
24.	2,486		2,486
25.	2,486		2,486
26.	2,486		2,486
27.	2,486		2,486
28.	2,486		2,486
29.	2,486		2,486
30.	2,486		2,486
31.	2,486		2,486
32.	2,486		2,486
33.	2,486		2,486
34.	3,060		3,060
35.	3,060		3,060

	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
36.	3,060		3,060
37.	3,060		3,060
38.	3,060		3,060
39.	3,060		3,060
40.	3,060		3,060
41.	3,060		3,060
42.	3,060		3,060
43.	3,060		3,060
44.	3,060		3,060
45.	3,060		3,060
46.	3,060		3,060
47.	3,060		3,060
48.	3,852		3,852
49.	3,852		3,852
50.	3,852		3,852
51.	3,852		3,852
52.	3,852		3,852
53.	3,852		3,852
54.	3,852		3,852
55.	3,852		3,852
56.	3,852		3,852
57.	3,852		3,852
58.	3,852		3,852
59.	3,852		3,852
60.	3,852		3,852
61.	3,852		3,852
62.	3,852		3,852
63.	3,852		3,852
64.	2,350		2,350
65.	4,208		4,208
66.	4,208		4,208
67.	4,208		4,208
68.	4,208		4,208
69.	4,208		4,208
70.	4,208		4,208
71.	4,208		4,208
72.	4,208		4,208
73.	4,208		4,208
74.	4,208		4,208
75.	4,208		4,208
76.	4,208		4,208
77.	4,208		4,208
78.	4,208		4,208
79.	4,208		4,208
80.	4,208		4,208
81.	4,208		4,208
82.	4,208		4,208
83.	4,208		4,208
84.	4,208		4,208
85.	4,208		4,208
86.	4,208		4,208
87.	4,208		4,208
88.	4,208		4,208

	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
89.	4,208		4,208
90.	4,454		4,454
91.	5,273		5,273
92.	6,011		6,011
93.	6,120		6,120
94.	5,109		5,109
95.	6,503		6,503
96.	1,311		1,311
97.	7,869		7,869
98.	7,869		7,869
99.	7,869		7,869
100.	8,115		8,115
101.	7,213		7,213
102.	8,115		8,115
103.	9,180		9,180
104.	9,180		9,180
105.	8,880		8,880
106.	6,858		6,858
107.	9,180		9,180
108.	5,847		5,847
109.	10,000		10,000
110.	6,530		6,530
111.	1,831		1,831
112.	10,000		10,000
113.	10,000		10,000
114.	10,000		10,000
115.	10,000		10,000
116.	10,000		10,000
117.	10,000		10,000
118.	10,000		10,000
119.	10,000		10,000
120.	10,000		10,000
121.	10,000		10,000
122.	3,962		3,962
123.	10,000		10,000
124.	10,000		10,000
125.	10,000		10,000
126.	10,000		10,000
127.	10,000		10,000
128.	10,000		10,000
129.	10,000		10,000
130.	10,000		10,000
131.	10,000		10,000
132.	10,000		10,000
133.	10,000		10,000
134.	10,000		10,000
135.	10,000		10,000
136.	10,000		10,000
137.	10,000		10,000
138.	10,000		10,000
139.	10,000		10,000
140.	10,000		10,000
141.	10,000		10,000

	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
142.	10,000		10,000
143.	10,000		10,000
144.	10,000		10,000
145.	10,000		10,000
146.	10,000		10,000
147.	10,000		10,000
148.	10,000		10,000
149.	10,000		10,000
150.	10,000		10,000
151.	10,000		10,000
152.	10,000		10,000
153.	10,000		10,000
154.	10,000		10,000
155.	10,000		10,000
156.	10,000		10,000
157.	10,000		10,000
158.	10,000		10,000
159.	10,000		10,000
160.	10,000		10,000
161.	10,000		10,000
162.	10,000		10,000
163.	10,000		10,000
164.	10,000		10,000
165.	10,000		10,000
166.	10,000		10,000
167.	10,000		10,000
168.	10,000		10,000
169.	10,000		10,000
170.	10,000		10,000
171.	9,071		9,071
172.	10,000		10,000
173.	9,235		9,235
174.	10,000		10,000
175.	10,000		10,000
176.	6,557		6,557
177.	10,000		10,000
178.	10,000		10,000
179.	10,000		10,000
180.	10,000		10,000
181.	10,000		10,000
182.	10,000		10,000
183.	10,000		10,000
184.	10,000		10,000
185.	10,000		10,000
186.	10,000		10,000
187.	10,000		10,000
188.	10,000		10,000
189.	10,000		10,000
190.	10,000		10,000
191.	10,000		10,000
192.	10,000		10,000
193.	10,000		10,000
194.	10,000		10,000

	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
195.	10,000		10,000
196.	10,000		10,000
197.	10,000		10,000
198.	10,000		10,000
199.	10,000		10,000
200.	10,000		10,000
201.	10,000		10,000
202.	10,000		10,000
203.	10,000		10,000
204.	10,000		10,000
205.	10,000		10,000
206.	10,000		10,000
207.	10,000		10,000
208.	10,000		10,000
209.	10,000		10,000
210.	10,000		10,000
211.	10,000		10,000
212.	10,000		10,000
213.	10,000		10,000
214.	10,000		10,000
215.	10,000		10,000
216.	10,000		10,000
217.	10,000		10,000
218.	10,000		10,000
219.	10,000		10,000
220.	10,000		10,000
221.	10,000		10,000
222.	10,000		10,000
223.	10,000		10,000
224.	10,000		10,000
225.	10,000		10,000
226.	10,000		10,000
227.	10,000		10,000
228.	10,000		10,000
229.	10,000		10,000
230.	10,000		10,000
231.	10,000		10,000
232.	10,000		10,000
233.	10,000		10,000
234.	10,000		10,000
235.	10,000		10,000
236.	10,000		10,000
237.	10,000		10,000
238.	10,000		10,000
239.	10,000		10,000
240.	10,000		10,000
241.	10,000		10,000
242.	2,541		2,541
243.	10,000		10,000
244.	10,000		10,000
245.	10,000		10,000
246.	7,213		7,213
247.	10,000		10,000

	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
248.	10,000		10,000
249.	5,874		5,874
250.	10,000		10,000
251.	10,000		10,000
252.	10,000		10,000
253.	10,000		10,000
254.	10,000		10,000
255.	10,000		10,000
256.	10,000		10,000
257.	10,000		10,000
258.	10,000		10,000
259.	10,000		10,000
260.	10,000		10,000
261.	10,000		10,000
262.	10,000		10,000
263.	10,000		10,000
264.	10,000		10,000
265.	10,000		10,000
266.	10,000		10,000
267.	10,000		10,000
268.	10,000		10,000
269.	10,000		10,000
270.	10,000		10,000
271.	10,000		10,000
272.	10,000		10,000
273.	10,000		10,000
274.	10,000		10,000
275.	10,000		10,000
276.	10,000		10,000
277.	10,000		10,000
278.	10,000		10,000
279.	10,000		10,000
280.	10,000		10,000
281.	10,000		10,000
282.	10,000		10,000
283.	10,000		10,000
284.	10,000		10,000
285.	10,000		10,000
286.	10,000		10,000
287.	5,874		5,874
288.	10,000		10,000
289.	10,000		10,000
290.	10,000		10,000
291.	10,000		10,000
292.	10,000		10,000
293.	10,000		10,000
294.	10,000		10,000
295.	10,000		10,000
296.	10,000		10,000
297.	10,000		10,000
298.	10,000		10,000
299.	10,000		10,000
300.	10,000		10,000

	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
301.	10,000		10,000
302.	10,000		10,000
303.	10,000		10,000
304.	10,000		10,000
305.	98		98
306.	10,000		10,000
307.	10,000		10,000
308.	10,000		10,000
309.	10,000		10,000
310.	10,000		10,000
311.	10,000		10,000
312.	10,000		10,000
313.	10,000		10,000
314.	10,000		10,000
315.	10,000		10,000
316.	10,000		10,000
317.	10,000		10,000
318.	10,000		10,000
319.	10,000		10,000
320.	10,000		10,000
321.	10,000		10,000
322.	10,000		10,000
323.	10,000		10,000
324.	10,000		10,000
325.	10,000		10,000
326.	10,000		10,000
327.	10,000		10,000
328.	10,000		10,000
329.	10,000		10,000
330.	10,000		10,000
331.	6,721		6,721
332.	10,000		10,000
333.	10,000		10,000
334.	10,000		10,000
335.	10,000		10,000
336.	10,000		10,000
337.	10,000		10,000
338.	10,000		10,000
339.	10,000		10,000
340.	10,000		10,000
341.	10,000		10,000
342.	10,000		10,000
343.	10,000		10,000
344.	10,000		10,000
345.	10,000		10,000
346.	10,000		10,000
347.	10,000		10,000
348.	10,000		10,000
349.	10,000		10,000
350.	10,000		10,000
351.	10,000		10,000
352.	10,000		10,000
353.	10,000		10,000

	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
354.	7,600		7,600
355.	10,000		10,000
356.	3,306		3,306
357.	10,000		10,000
358.	10,000		10,000
359.	10,000		10,000
360.	6,858		6,858
361.	10,000		10,000
362.	10,000		10,000
363.	10,000		10,000
364.	10,000		10,000
365.	3,087		3,087
366.	3,388		3,388
367.	10,000		10,000
368.	10,000		10,000
369.	10,000		10,000
370.	10,000		10,000
371.	10,000		10,000
372.	10,000		10,000
373.	10,000		10,000
374.	10,000		10,000
375.	10,000		10,000
376.	10,000		10,000
377.	10,000		10,000
378.	10,000		10,000
379.	10,000		10,000
380.	10,000		10,000
381.	10,000		10,000
382.	10,000		10,000
383.	10,000		10,000
384.	10,000		10,000
385.	10,000		10,000
386.	10,000		10,000
387.	10,000		10,000
388.	10,000		10,000
389.	10,000		10,000
390.	10,000		10,000
391.	10,000		10,000
392.	10,000		10,000
393.	10,000		10,000
394.	10,000		10,000
395.	10,000		10,000
396.	10,000		10,000
397.	10,000		10,000
398.	10,000		10,000
399.	10,000		10,000
400.	10,000		10,000
401.	10,000		10,000
402.	10,000		10,000
403.	10,000		10,000
404.	10,000		10,000
405.	10,000		10,000
406.	10,000		10,000

	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
407.	4,372		4,372
408.	10,000		10,000
409.	10,000		10,000
410.	10,000		10,000
411.	10,000		10,000
412.	10,000		10,000
413.	8,251		8,251
414.	10,000		10,000
415.	5,191		5,191
416.	10,000		10,000
417.	10,000		10,000
418.	10,000		10,000
419.	10,000		10,000
420.	10,000		10,000
421.	10,000		10,000
422.	3,232		3,232
423.	10,000		10,000
424.	10,000		10,000
425.	10,000		10,000
426.	10,000		10,000
427.	10,000		10,000
428.	7,213		7,213
429.	7,213		7,213
430.	10,000		10,000
431.	10,000		10,000
432.	10,000		10,000
433.	10,000		10,000
434.	10,000		10,000
435.	10,000		10,000
436.	7,213		7,213
437.	7,213		7,213
438.	2,131		2,131
439.	10,000		10,000
440.	10,000		10,000
441.	7,180		7,180
442.	7,596		7,596
443.	9,689		9,689
444.	5,874		5,874
445.	7,213		7,213
446.	7,049		7,049
447.	5,874		5,874
448.	10,000		10,000
449.	3,142		3,142
450.	10,000		10,000
451.	10,000		10,000
452.	10,000		10,000
453.	7,596		7,596
454.	7,596		7,596
455.	7,342		7,342
456.	2,131		2,131
457.	10,000		10,000
458.	10,000		10,000
459.	10,000		10,000

	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
460.	10,000		10,000
461.	10,000		10,000
462.	10,000		10,000
463.	10,000		10,000
464.	10,000		10,000
465.	10,000		10,000
466.	10,000		10,000
467.	10,000		10,000
468.	10,000		10,000
469.	10,000		10,000
470.	10,000		10,000
471.	10,000		10,000
472.	7,200		7,200
473.	7,596		7,596
474.	2,213		2,213
475.	1,093		1,093
476.	10,000		10,000
477.	10,000		10,000
478.	10,000		10,000
479.	10,000		10,000
480.	10,000		10,000
481.	10,000		10,000
482.	10,000		10,000
483.	10,000		10,000
484.	10,000		10,000
485.	10,000		10,000
486.	10,000		10,000
487.	10,000		10,000
488.	10,000		10,000
489.	10,000		10,000
490.	10,000		10,000
491.	10,000		10,000
492.	3,005		3,005
493.	10,000		10,000
494.	10,000		10,000
495.	10,000		10,000
496.	10,000		10,000
497.	10,000		10,000
498.	10,000		10,000
499.	10,000		10,000
500.	10,000		10,000
501.	10,000		10,000
502.	10,000		10,000
503.	10,000		10,000
504.	10,000		10,000
505.	10,000		10,000
506.	5,738		5,738
507.	10,000		10,000
508.	10,000		10,000
509.	10,000		10,000
510.	10,000		10,000
511.	10,000		10,000
512.	8,290		8,290

	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
513.	1,475		1,475
514.	7,213		7,213
515.	9,208		9,208
516.	9,208		9,208
517.	9,208		9,208
518.	9,208		9,208
519.	9,208		9,208
520.	9,208		9,208
521.	9,208		9,208
522.	9,208		9,208
523.	9,208		9,208
524.	9,208		9,208
525.	9,208		9,208
526.	9,208		9,208
527.	9,208		9,208
528.	9,208		9,208
529.	9,208		9,208
530.	9,208		9,208
531.	9,016		9,016
532.	9,016		9,016
533.	9,016		9,016
534.	8,443		8,443
535.	8,443		8,443
536.	8,443		8,443
537.	8,443		8,443
538.	8,443		8,443
539.	8,443		8,443
540.	8,443		8,443
541.	8,443		8,443
542.	8,443		8,443
543.	8,443		8,443
544.	8,443		8,443
545.	8,443		8,443
546.	8,443		8,443
547.	8,443		8,443
548.	8,443		8,443
549.	8,443		8,443
550.	8,443		8,443
551.	2,514		2,514
552.	7,596		7,596
553.	7,596		7,596
554.	7,596		7,596
555.	7,596		7,596
556.	7,596		7,596
557.	7,596		7,596
558.	7,596		7,596
559.	7,213		7,213
560.	7,213		7,213
561.	7,213		7,213
562.	7,213		7,213
563.	7,213		7,213
564.	7,213		7,213
565.	7,213		7,213

	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
566.	6,831		6,831
567.	3,689		3,689
568.	6,721		6,721
569.	6,831		6,831
570.	6,831		6,831
571.	6,831		6,831
572.	6,721		6,721
573.	27		27
574.	5,956		5,956
575.	5,956		5,956
576.	5,956		5,956
577.	5,956		5,956
578.	5,956		5,956
579.	5,956		5,956
580.	5,956		5,956
581.	5,956		5,956
582.	5,956		5,956
583.	5,956		5,956
584.	5,956		5,956
585.	5,956		5,956
586.	5,956		5,956
587.	5,956		5,956
588.	5,956		5,956
589.	5,956		5,956
590.	5,956		5,956
591.	4,344		4,344
592.	3,579		3,579
593.	3,817		3,817
594.	3,579		3,579
595.	3,579		3,579
596.	3,579		3,579
597.	2,131		2,131
598.	2,131		2,131
599.	2,038		2,038
600.	2,131		2,131
601.	2,131		2,131
602.	2,131		2,131
603.	2,131		2,131
604.	1,475		1,475
605.	1,475		1,475
606.	1,475		1,475
607.	1,475		1,475
608.	1,475		1,475
609.	1,475		1,475
610.	1,475		1,475
611.	1,475		1,475

Ontario apprenticeship training tax credit (total of amounts in column N) 500 — 4,878,911 **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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 568

ONTARIO BUSINESS-RESEARCH INSTITUTE TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Networks Inc.	87086 5821 RC0001	2012-12-31

- Use this schedule to claim the Ontario business-research institute tax credit (OBRITC) under section 97 of the *Taxation Act, 2007* (Ontario).
- The OBRITC is a 20% refundable tax credit based on qualified expenditures incurred in Ontario under an eligible contract with an eligible research institute (ERI).
- A list of eligible research institutes and the applicable ERI codes for eligible contracts can be found on our website. Go to **www.cra.gc.ca/ctao** and select "business-research institute tax credit".
- The criteria for a corporation to be eligible for the OBRITC include the eligibility requirements in Part 1 of this schedule.
- The annual qualified expenditure limit is $20 million. If a corporation is associated with other corporations at any time in the calendar year, the $20 million limit must be allocated among the associated corporations.
- Qualifying corporations are defined in subsection 97(3) of the *Taxation Act, 2007* (Ontario).
- For each eligible contract, you must complete a separate Schedule 569, *Ontario Business-Research Institute Tax Credit Contract Information*.
- Keep the eligible contract to support your claim. Do not submit the contract with the *T2 Corporation Income Tax Return*.
- To claim the OBRITC, include the following with the *T2 Corporation Income Tax Return*:
  – a completed copy of this schedule; and
  – a completed copy of Schedule 569 for each eligible contract.

Part 1 – Eligibility

1. Did the corporation, for the tax year, carry on business in Ontario through a permanent establishment in Ontario? . . . . **100** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax for the tax year under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **105** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, the corporation is **not eligible** for the OBRITC.

Part 2 – Qualified expenditure limit for the tax year

Was the corporation associated at any time in the tax year with another corporation? . . . . **200** 1 Yes [X] 2 No [ ]

If the corporation answered **no** at line 200, enter $20,000,000 on line 205. If the corporation answered **yes** at line 200, complete Part 3 and enter on line 205 the expenditure limit allocated to the corporation in column 310 in Part 3.

Qualified expenditure limit . . . . **205** 20,000,000 A

If the tax year is 51 weeks or more, enter amount A on line 210.

If the tax year of the filing corporation is less than 51 weeks, complete the following proration calculation:

Amount A 20,000,000 x days in the tax year 366 / 365 = ... ______ B

Qualified expenditure limit for the tax year (amount A or amount B, whichever applies) . . . . **210** 20,000,000 C

Part 3 – Allocation of the $20 million expenditure limit between associated corporations

Use this part to allocate the $20 million expenditure limit to the filing corporation and all its associated corporations for each of their tax years ending in the calendar year. See subsection 38(4) of Ontario Regulation 37/09 for expenditure limit allocation rules for associated corporations. Attach additional schedules if you need more space.

	Name of all associated corporations, including the filing corporation (include the associated corporations that have a tax year that ends in the calendar year) 300	Business Number (enter "NR" if corporation is not registered) 305	Expenditure limit allocated 310
1.	Hydro One Networks Inc.	87086 5821 RC0001	20,000,000
2.	Hydro One Inc.	86999 4731 RC0001	
3.	Hydro One Remote Communities Inc.	87083 6269 RC0001	
4.	Hydro One Telecom Inc.	86800 1066 RC0001	
5.	Hydro One Telecom Link Limited	88786 7513 RC0001	
6.	Hydro One Brampton Networks Inc.	86486 7635 RC0001	
7.	Hydro One Lake Erie Link Management Inc	87892 1519 RC0001	
8.	Hydro One Lake Erie Link Company Inc.	87560 6519 RC0001	
		Total expenditure limit (cannot exceed $20 million) 315	20,000,000 D

Enter the expenditure limit allocated to the corporation on line 205 in Part 2.

Part 4 – Calculation of the Ontario business-research institute tax credit

Total number of eligible contracts used to determine the OBRITC for this tax year . . . 400 4

Total qualified expenditures for all eligible contracts identified on line 400 for this tax year (total of amounts on line 310 in Part 3 of each **Schedule 569**) . . . 405 936,875 E

Qualified expenditure limit for the tax year (amount C in Part 2) . . . 20,000,000 F

Qualified expenditures for the OBRITC for the tax year (amount E or F, whichever is less) . . . 410 936,875

Ontario business-research Institute tax credit (line 410 x 20 %) . . . 187,375 G

Enter amount G on line 470 of Schedule 5, *Tax Calculation Supplementary – Corporations*.

HYDRO ONE NETWORKS INC.

Calculation of Utility Income Taxes
Historic Year
2012 Networks Tax Return Allocation to TX and DX
Year Ending December 31
($ Millions)

Line No.	Particulars		Networks		Transmission		Distribution
	Calculation of Federal and ON Taxable Income						
1	Net Income Before Tax (NIBT)	$	838.3	$	536.4	$	301.9
2	**Required Adjustments to accounting NIBT**						
3	**Recurring items included in Revenue Requirement (RR):**						
4	Other Post Employment Benefit expense greater than payments		0.5		(0.5)		1.0
5	Depreciation and amortization		628.4		320.3		308.1
6	Capital Cost Allowance		(779.0)		(448.4)		(330.6)
7	Cumulative Eligible Capital		(10.1)		(9.8)		(0.3)
8	Removal costs		(9.7)		(2.9)		(6.8)
9	Environmental costs paid		(15.1)		(5.9)		(9.2)
10	Non-deductible items (50% Meals & entertainment / interest)		5.8		3.6		2.2
11	R & D Fed ITC/ Apprenticeship (prior yr addback)		4.8		1.4		3.4
12	Capitalized overhead costs deducted		(53.6)		(30.6)		(23.0)
13	Capital additions deducted for accounting		14.1		5.5		8.6
14	Capitalized Pension cost deductions		(86.2)		(42.4)		(43.8)
15		$	(300.1)	$	(209.7)	$	(90.4)
16	**Deferral accounts not part of RR:**						
17	RSVA/RRRP		3.2		0.0		3.2
18	Restricted Depreciation		16.3		16.3		0.0
19	Smart meter costs deferred		(1.2)		0.0		(1.2)
20	Tx Export credit/Deferred export Rev		8.3		8.3		0.0
21	Deferred Pension		(18.2)		(1.9)		(16.3)
22	Deferral a/c's etc.		1.9		2.4		(0.5)
23	Tax Changes deferral a/c		6.3		(0.8)		7.1
24	**Riders 3/6/8**		2.8		0.0		2.8
25	Station Rev. and secondary Land Use		14.0		14.0		0.0
26		$	33.4	$	38.3	$	(4.9)
27	Reversal of accounting adjustments not part of RR:						
28	**Contingent liability movement**		2.4		0.8		1.6
29	Capitalized interest deductible for tax		(58.0)		(39.6)		(18.4)
30	Capitalized SRED Expenditures deductible for tax		(26.0)		(6.8)		(19.2)
31		$	(81.6)	$	(45.6)	$	(36.0)
32	Recurring items not part of RR:						
33	Capital Contribution (CCRA True up)		8.4		8.4		0.0
34	Cumulative Eligible Capital		(1.8)		0.0		(1.8)
35			6.6		0.0		(1.8)
36	Immaterial items not in business plan detail:						
14	Reverse Insurance proceeds included in NIBT		(4.1)		(4.1)		0.0
15	Net Underwriting/Finance costs		(4.2)		(2.6)		(1.6)
16	Tenant Inducement		(1.9)		(0.9)		(1.0)
17	Other		1.2		0.3		0.9
18			(9.0)		(7.3)		(1.7)
19							
20	NET Adjustments to Accounting NIBT	$	(350.7)	$	(224.3)	$	(134.8)
21							
22	Taxable Income	$	487.6	$	312.1	$	167.1

NOTE:
Transmission includes Five Nations data

HYDRO ONE NETWORKS INC.

Calculation of Capital Cost allowance (CCA)
Historic Year
2012 Networks Tax Return CCA Allocation to TX and DX
Year Ending December 31
($ Millions)

2012 Transmission:

2012 TX CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CA Rate (%	CCA	Closing UCC
1	2,391.60	0.5	2,392.1	0.3	2,391.9	4%	95.7	2,296.46
2	686.10	-	686.1	-	686.1	6%	41.2	644.93
3	230.40	23.6	254.0	11.8	242.2	5%	12.1	241.85
6	67.40	5.6	73.0	2.8	70.2	10%	7.0	65.96
7	-	-	-	-	0.0	15%	0.0	0.03
8	36.60	6.9	43.5	5.7	37.9	20%	7.6	35.96
9	1.60	-	1.6	-	1.6	25%	0.4	1.21
10	52.30	11.2	63.5	5.6	57.9	30%	17.4	46.13
12	9.80	18.9	28.7	9.4	19.3	100%	19.3	9.45
13	0.90	0.2	1.1	0.1	1.0	N/A	0.4	0.72
17	34.40	15.2	49.6	7.6	42.0	8%	3.4	46.27
35	0.30	-	0.3	-	0.3	7%	0.0	0.29
42	85.00	13.9	98.9	7.0	91.9	12%	11.0	87.87
45	1.10	-	1.1	-	1.1	45%	0.5	0.63
46	3.20	1.9	5.1	0.9	4.2	30%	1.3	3.87
47	1,929.20	786.5	2,715.7	389.3	2,326.4	8%	186.1	2,529.59
50	47.40	71.6	119.0	37.0	82.0	55%	45.1	73.87
TX UCC	5,577.3	956.0	6,533.3	477.5	6,056.0		448.4	6,085.1
TX CEC Continuity	57.2	82.3	139.5		139.5	7%	9.8	129.7
					Total CCA		458.2	
					Less First Nations		(0.3)	
							457.9	

2012 Distribution:

CCA Class	Opening UCC	Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,751.7	1.7	1,753.4	0.8	1,752.5	4%	70.1	1,683.3
2	309.5	-	309.5	-	309.5	6%	18.6	290.9
3	13.0	-	13.0	-	13.0	5%	0.7	12.3
6	11.6	1.5	13.1	0.8	12.4	10%	1.2	11.9
8	68.8	66.8	135.6	39.7	95.9	20%	19.2	116.4
9	2.2	-	2.2	-	2.2	25%	0.5	1.6
10	94.9	37.2	132.1	18.6	113.5	30%	34.0	98.1
12	11.8	19.7	31.5	9.9	21.6	100%	21.6	9.9
13	3.7	0.4	4.1	0.2	3.9	SL	0.6	3.4
17	6.3	2.1	8.4	1.0	7.3	8%	0.6	7.7
42	0.2	-	0.2	-	0.2	12%	0.0	0.1
45	0.7	-	0.7	-	0.7	45%	0.3	0.4
46	0.1	1.5	1.6	0.7	0.9	30%	0.3	1.4
47	1,623.2	315.5	1,938.7	157.5	1,781.2	8%	142.5	1,796.2
50	30.4	19.9	50.3	13.3	37.0	55%	20.4	30.0

HYDRO ONE NETWORKS INC.

Calculation of Apprenticeship, Education and SR&ED Tax Credits
Historic Year
2012 Networks Tax Return Tax Credit Allocation to TX and DX
Year Ending December 31
($ Millions)

Line No	Particulars	Networks	Transmission	Distribution
1	ON Coop Education Credit	$ 1,114,901	$ 525,036	$ 589,865
2	Eligible Positions	372	175	197
3				
4	ON Apprenticeship Credit	$ 4,878,911	$ 2,303,074	$ 2,575,837
5	Eligible Positions	611	288	323
6				
7	Federal Apprenticeship Credit	$ 346,346	$ 169,497	$ 176,849
8	Eligible positions	203	99	104
9				
10	SR&ED FED	$ 5,528,327	$ 1,382,030	$ 4,146,297
11	SR&ED ON	$ 1,221,589	$ 306,760	$ 914,829
12	Ontario Business Research Tax Credit	$ 187,375	$ 49,063	$ 138,312