SUSTAINING CAPITAL

1.0 INTRODUCTION

Distribution Sustaining Capital represents investments required to ensure that existing distribution system facilities function as originally designed. Hydro One Distribution manages its distribution sustaining capital program by dividing the program into three program categories, namely: stations, lines, and meters.

Stations, lines, and meter program categories include investments in equipment and related components required to deliver electricity through the distribution system, as well as investments that facilitate the efficient use of joint-use of assets. Investments covered under the Sustaining Capital program are proposed for the purpose of maintaining the long term and short term functionality of assets, to ensure public and employee safety, comply with regulations and contractual requirements, and to provide a level of reliability that is aligned with corporate objectives.

A description of the generic process for planning Sustaining Capital investments is provided in Exhibit A, Tab 14, Schedule 5. Details of Hydro One Distribution's Sustaining specific Capital programs and proposed spending levels for 2010 and 2011 are described below.

2.0 DISCUSSION

Distribution stations, lines and meter assets, and their components, are subject to deterioration that will eventually impede their ability to function as originally designed. Asset deterioration depends on factors such as geographic environment and location, utilization, age, weather, and maintenance practices. As assets deteriorate, equipment performance and reliability usually suffers, resulting in increased environmental risks, an increase in potential safety hazards to the public and employees, and decreased system reliability. Ultimately, assets deteriorate to the point that they are no longer able to perform their function(s) in a cost-effective manner, at which point replacement becomes necessary.

Sustaining Capital programs fund both planned work and demand (unplanned) work. Planned work is required to preserve functionality of the existing distribution system by replacing deteriorated components with new components that are designed to perform an equivalent function. The identification of specific facilities for possible replacement is based on data collected during the Asset Condition Assessment ("ACA") process described in Exhibit D1, Tab 2, Schedule 1. The condition of assets is one consideration in determining replacement. Other factors include historic performance, asset criticality, availability of spare equipment, load growth, and local customer impacts as well as the business drivers that form part of the work program prioritization process described in Exhibit A, Tab 14, Schedule 6. The prioritization process allows all distribution programs to be ranked and compared to one another so that investments can be directed to where they provide the maximum business value.

Demand capital work involves asset replacement that is required during service interruptions and in response to contractual and other commitments with road authorities and joint use partners (i.e. cable and telecommunication companies). The varying nature of this work requires Hydro One Distribution to forecast costs based on historical averages with adjustments made to reflect recent changes in expenditure patterns or work requirements.

Demand work requires an immediate or timely response to customer needs and is initiated by interruptions to service, line and station inspection findings, and by request from customer and property owners. Hydro One Distribution maintains infrastructure, equipment and resources to respond to these issues within the time lines specified by the Distribution System Code. Planned work on the other hand, does not generally pose the same degree of urgency and is scheduled over time, based on knowledge of the condition of the assets.

The Sustaining Capital spending for 2010 and 2011, as well as the spending in prior years is provided in Table 1 below.

Table 1
Sustaining Capital
($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Stations	8.5	7.7	12.5	13.3	14.0	15.3
Lines	162.1	138.8	157.2	161.6	168.0	183.1
Meters	1.6	0.4	1.0	1.6	3.8	4.1
Total	**172.2**	**146.9**	**170.7**	**176.5**	**185.8**	**202.5**

The increase in spending for 2010 and 2011 relative to historic expenditures is largely attributed to the following:

- An increase in planned pole replacements for 2010 and then again in 2011 based on ACA findings indicating a need to address a subset of poles that are showing signs of premature decay.
- An increase to planned overhead line and submarine cable refurbishment in 2010, which is maintained in 2011, to address assets determined to be at end of life and to mitigate reliability and safety risks.
- The implementation of PCB equipment replacement programs as a result of new PCB regulations.

- Updated forecasts for demand activities such as storm response costs and joint use and line relocations to reflect historical spending.

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

2.1 Stations

Hydro One Distribution has 1,005 distributing and regulating station facilities, which are used for the delivery of power, voltage transformation and switching. Station facilities contain many of the following components: power transformers, instrument devices, reclosers, fuses, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station service supplies, grounding systems, fences, and buildings.

Hydro One Distribution's service to customers is also performed with a fleet of 28 mobile substations used primarily for emergency response to power disruptions at stations. The mobile substations are also used during planned maintenance programs and capital refurbishment at distributing stations to reduce power interruptions. Investments for mobile substation are included in the Sustaining Capital program to ensure these mobile assets are available for the above purposes.

Stations Sustaining Capital funding covers capital investments required to replace or upgrade assets located within distributing and regulating stations, and mobile substations. The work is divided among three programs. Funding of the three programs for 2010 and 2011, along with the spending levels for the bridge and historic years are provided in Table 2 below.

Table 2
Stations Sustaining Capital
($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Strategic Spare Transformers	2.8	0.6	2.8	4.9	3.6	4.1
Mobile Substation Investments	1.0	0.3	1.7	1.5	2.5	2.8
Station Projects & Demand	4.7	6.8	8.0	6.9	7.9	8.4
Total	**8.5**	**7.7**	**12.5**	**13.3**	**14.0**	**15.3**

2.1.1 Management of Transformer Assets (Strategic Spares & Mobile Substations)

Power transformers are devices used to reduce the voltage of the electricity being distributed, and to provide voltage control. Distribution power transformers convert a high level voltage (typically 115kV, 44kV, or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 and 4.16 kV).

The management of transformer assets is a key component of the Stations Capital Sustaining program. The reliability of supply provided by power transformers is managed through proactive maintenance activities and a coordinated use of strategic spare transformers and mobile substations. These programs are interdependent and have proven to be a cost-effective approach for managing transformers for a largely rural utility such as Hydro One Distribution. This approach reduces capital expenditures for distribution facilities as discussed below while still providing reliable delivery of electricity to customers.

Hydro One Distribution's system is largely a radial system characterized by little or no load transfer capability, and by design the majority of distributing stations are equipped with only one power transformer. The consequence of this system design is that a transformer failure at a distributing station results in a service interruption to all customers supplied from that station. Since service to customers cannot be restored until the function of the distributing station is restored, in many instances mobile substations are dispatched to the affected station to provide service restoration. The mobile substation remains in place until such time as a spare transformer can be brought in to replace the failed unit. The extent to which spare transformers are available will influence the reliance on mobile stations for extended periods. Alternatives to this approach include having a spare a transformer at every distributing station or adding supply lines to provide a redundant supply. These alternatives have been assessed to be cost prohibitive on a system wide basis.

Mobile substations also facilitate maintenance at distributing stations by carrying the station load while the station is isolated for planned maintenance work. This approach permits the cost effective bundling of work while mitigating power disruptions to customers. The extent to which mobile substations are in-service for an extended period of time, due to unavailability of spare transformers, will limit the ability to complete the required planned maintenance and capital work at distributing stations.

Details of the programs used to manage strategic spare transformers and mobile substations are provided below.

2.1.1.1 Strategic Spare Transformers

Hydro One Distribution has 1,328 station transformers and 139 regulators in service. As discussed in Exhibit D1, Tab 2, Schedule 1, Asset Condition Assessment & Analysis, Hydro One's distribution stations have experienced an average of 23 transformer failures a year over the last 3 years. In a number of instances, station failures require removing the transformer off site and subsequent replacement from the strategic spare transformer inventory. The strategic spare inventory is maintained by purchasing new transformers if required and by refurbishing existing, unserviceable units (i.e. transformers that failed or were required to be removed from service based on poor condition as determined through the ACA process).

The majority of distribution transformers that fail, or that are found to be unserviceable based on ACA results, can be refurbished economically. Repair costs can vary significantly, from $15,000 to $150,000 per transformer, depending on the nature of the failure and whether the damage results from external or internal faults. Before a transformer is refurbished, Hydro One Distribution first determines whether the transformer is needed as a spare, and estimates the refurbishment costs by dismantling the transformer and assessing the extent of damage. If refurbishing the transformer versus buying a new transformer is economically justified and is technically acceptable, the existing transformer is refurbished and added to the pool of strategic spare transformers.

Due to the importance of these system elements to customer reliability, Hydro One Distribution maintains a spares inventory of transformers and regulators that is based on the number and type of transformers and regulators in-service, reliability of equipment in use and the availability of mobile substations. Historically, a number of spare station transformers are put into service and cannot be returned to the spares inventory. In these cases, the complement of spare transformers is reduced unless replacement transformers are purchased, or transformers become available through system reinforcement projects (i.e. transformer replaced in response to an increase in customer load is freed-up for another use). This program funds the purchase of transformers to maintain a spares compliment that meets system needs and ensures reliability.

Funding of this program enhances customer reliability by reducing the reliance placed on mobile substations for extended periods, making them available to respond to emergencies and to assist in carrying out the planned maintenance on distributing stations, thereby ensuring equipment performance.

The 2010 and 2011 spending requirements for this program are $3.6 million and $4.1 million respectively. Historically expenditures have fluctuated from year to year based on the number of failed transformers that are beyond repair and replaced by transformers from the spares pool. Those transformers removed from the spares pool that become permanent field installations need to be replaced in the spares inventory to maintain adequate spares coverage. In addition, system conditions and failures are monitored and if there is an appreciable increase in the failure rate of a specific class of transformer, there may be a need to increase the number of spares within the subject group to manage reliability to acceptable levels.

The 2010 spending covers the purchase of 4 new spare transformers. The 2011 spending involves the purchase of 4 new spare transformers and 1 regulator.

Funding reductions in this program would result in an increased utilization of mobile substations at failed transformer locations thereby negatively impacting planned maintenance and jeopardizing reliability at a number of distribution stations.

For additional details refer to the Investment Summary Document (ISD) in Exhibit D2, Tab 2, Schedule 3.

2.1.1.2 Mobile Substation Refurbishment

A mobile substation ("MUS") is essentially a distribution station mounted on a trailer suitable for traveling on public roads. These mobile units consist of a transformer, high voltage and low voltage switches, high voltage and low voltage fuses, and connecting bus. There are 28 of these units strategically located across the Province. The primary purpose of mobile substations is to provide emergency backup to distributing stations and restore service to customers following the failure of a station, but they also facilitate planned maintenance programs at distributing station assets by mitigating power disruption to customers. Given Hydro One Distribution's largely radial distribution system with single transformer distributing stations, the utilization of mobile substations provides a cost effective alternative to constructing redundant transformation at stations.

As mobile substations are utilized and age, the condition of their various components deteriorates. To maintain the condition of these units, periodic investments are required to replace critical electrical (e.g. transformers, reclosers) and mechanical (e.g. undercarriage, wheels, axles, suspension) components when routine maintenance cannot restore their integrity. Funding of this program allows for the efficient refurbishment of mobile substations based on the results of a monthly and yearly condition assessments required to ensure they are roadworthy, comply with Ministry of Transportation licensing requirements, and electrically capable.

The 2010 and 2011 spending requirements for this program are $2.5 million and $2.8 million. This level of spending is approximately $1.0 to $2.0 million above historic amounts and allows for the purchase of an additional MUS in 2010 and the refurbishment of two mobile substations in each year. The need to increase investment in the MUS fleet is driven by increasing maintenance needs associated with new PCB regulations (discussed in Exhibit C1, Tab2, Schedule 2) and the requirement to have adequate numbers and types of MUSs available. Inadequate investment in the MUS fleet, would have an adverse impact on station emergency response, on planned station maintenance capability, would jeopardize customer reliability and would negatively impact the ability of Hydro One Distribution to proceed with the PCB testing and retirement programs.

For additional details refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

2.1.2 Stations Projects and Demand (Unplanned)

Station Refurbishment Projects

The level of investment required to refurbish a station will vary as a function of the condition of the station. Some stations will require replacement of frost-heaved structures, power equipment components, or security fence replacements. In other cases, the work required may be more significant, such as transformer refurbishment or the complete rebuild of a station on an existing or a new site. The latter may be the case particularly for the older wood pole and timber structure station styles.

Station condition is determined using the ACA process as discussed in Exhibit D1, Tab 2, Schedule 1. Up to about 10 stations may be refurbished annually based on condition, utilization, criticality, and environmental risks. The number of stations scheduled for refurbishment on an annual basis at this time is currently less than 1% of all Hydro One distributing stations. Considering the age of these assets, (i.e. 30 to 40 years) this is a relatively low number of annual refurbishments, largely attributable to Hydro One Distribution's comprehensive maintenance program and the proactive management of transformer spares, as discussed in this Schedule and in Exhibit C1, Tab 2, Schedule 2.

Funding levels of this program will impact the amount of breakdown maintenance in future years and negatively impact customer reliability. The 2010 and 2011 spending for station refurbishment work is $3.2 million and $3.4 million respectively. These amounts are slightly greater than historic expenditures as larger station refurbishment projects are being undertaken, which contributes to the efficient bundling work. For additional details refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

Spill Containment Projects

Spill containment systems for distribution stations were not generally installed at the time of construction for most stations. As a result, a relatively small portion of Hydro One Distribution's stations (i.e. less than 5%) have spill containment systems. In the case of a transformer failure, these systems are capable of containing insulating oil and greatly minimizing risks to the environment.

Hydro One Distribution has identified high risk station sites that currently do not have spill containment systems and that would benefit from their installation. These high risk sites are typically in proximity to waterways and pose environmental risks should a transformer fail and insulating oil be released off of the station site. To mitigate risks at these sites, Hydro One Distribution intends to install spill containment systems. The 2010 and 2011 spending requirements for these installations is $1 million in each year. This level of spending is above historic levels in order to address the higher risk sites.

Component Replacement & Demand

Component replacement projects involve replacing such defective equipment as reclosers, surge arrestors, fences and switches that have been determined to be at end of life. Replacements are based on the condition of equipment and station components assessed during routine inspections, ACA and during planned and unplanned maintenance activities. Replacement decisions may also be made based on obsolescence, as is the case with the need to replace type D reclosers.

The demand work completed under this program covers the capital component of work required to address the failure of distributing and regulating station components and to correct emergency situations that could cause a power interruption or present a safety hazard. When station components fail, the consequence is typically a service interruption to customers. Station interruptions can impact a large number of customers, typically from 1,000 to 10,000 customers per interruption. Emergency and corrective work must be carried out in a timely manner in order to minimize the risks to customer reliability, and public and employee safety. In most cases, smaller components such as reclosers, 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 and then returning it to that specific site. If a prolonged service interruption is anticipated, service is typically restored through the temporary use of a mobile substation or replacing the failed unit with a spare transformer.

This program covers the capital corrective costs associated with components and emergency work at stations that involve plant retirement. Work that does not involve capital components or plant retirements is covered under the Sustaining OM&A, Exhibit C1, Tab 2, Schedule 2.

The 2010 and 2011 spending requirements for both component replacement and demand work are $3.8 million $4.0 million respectively. These amounts are consistent with historic years with the exception of 2008, which was greater as a result of additional component replacement and emergency work. For additional details refer to the ISDs in Exhibit D2, Tab 2, Schedule 3.

<u>Summary</u>

The 2010 and 2011 spending requirement for all Stations Sustaining Capital is $14.0 million and $15.3 million respectively. The proposed funding is greater than historic expenditures due to aforementioned increases in spares, MUS, and spill containment funding. It should be noted that spending from year to year can vary due to the influence of various factors such as the number and type of stations to be refurbished, number of failures, condition of assets, asset performance, and availability of spare equipment.

Reductions in this program could result in defective equipment and station components remaining in service for longer periods of time, thereby threatening customer supply reliability and the environment in the case of an oil spill . Reduced funding would also constrain the availability of spare transformers and MUSs, thereby limiting planned station maintenance and PCB testing.

2.2 Lines

Distribution lines total 120,200 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, transformers, switches, fuses, surge arresters, voltage regulators, capacitors, insulators, reclosers and grounding devices. A small proportion of distribution line inventory is located underground in some of the more urban locations or underwater (submarine) for servicing cottages and residences on islands. The underground and submarine inventory represents approximately 5% of the total circuit kilometres.

Sustaining Capital funding for lines includes capital investments required to maintain existing assets associated with overhead, underground, and submarine distribution lines. The work is divided among three programs as noted in Table 3. Funding for 2010 and 2011 along with spending for the bridge and historic years are provided in Table 3 below.

Table 3
Lines Sustaining Capital
($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Trouble Call & Storm Damage (d)	90.6	51.7	62.0	60.1	59.3	59.2
Joint Use & Relocations (d)	24.0	27.1	31.2	27.5	30.4	30.5
Asset Replacements	47.5	60.0	64.0	74.0	78.3	93.5
Total	**162.1**	**138.8**	**157.2**	**161.6**	**168.0**	**183.1**

(d) – indicates this is a demand program

2.2.1 Trouble Call and Storm Damage Response

This demand program provides capital investment for responding to problems on distribution lines that require immediate attention as a result of trouble calls or storm damage.

A trouble call typically captures the work required to restore the supply of power to customers following an unplanned interruption. However, a trouble call may also be required in response to a customer complaint (e.g. about power quality) or to correct a defect on a distribution asset that, if not addressed, could present a safety concern or potentially result in an interruption of power to customers. Hydro One Distribution must address trouble calls in order to comply with legal and regulatory requirements, to correct known hazardous problems and to maintain reliable electric service in accordance with good utility practice.

The majority of costs associated with trouble calls are incurred in the Sustaining OM&A program described in Exhibit C1, Tab 2, Schedule 2. In cases where capital plant is replaced as part of a trouble call (e.g. wood poles, submarine cable), all labour and material costs are capitalized under this program. Where a trouble call is as a result of damage to the distribution system caused by a third party (e.g. motor vehicle accident), Hydro One Distribution endeavours to recover the cost of making the repairs. Any costs recovered are credited to this program. Historically, damage by third party interference has totaled approximately $4 to $5 million per year with recovery of approximately $3 to $4 million annually.

Hydro One Distribution also capitalizes storm restoration costs where a storm results in the replacement of capital plant units and the distribution system experiences significant damage. Storms normally interrupt the supply of power to many thousands of customers. The impact storms have on Hydro One Distribution's system during any given year will depend on the number, type (e.g. wind, snow, ice) and severity of the storms. Historically the number of storms varies widely and the number of days affected by storms has ranged from 20 to over 50 days annually. There is also variation in the number of "force majeure" storms impacting the distribution system, with force majeure defined as a major storm affecting more than 10% of Hydro One Distribution's customers. Hydro One Distribution's experience indicates that the lines system can expect at least one force majeure storm in any given year and that this number can rise to as high as 8 as experienced in 2006, which was a year of unusually high storm activity resulting in extensive damage to the distribution system. Given the variability in the number, type and severity of storms, storm-related damage can change significantly from one year to the next.

The extent of storm-related damage is also affected by work in other sustainment programs. Reducing vegetation management will increase the likelihood of trees and branches contacting a line under storm conditions. This is attributed to vegetation growth encroaching on the right-of-way and damaged or diseased trees remaining near line facilities for longer periods of time. As well, if assets in need of repair or replacement are not addressed, there is an increased likelihood that assets such as poles may fail under adverse weather conditions.

All work associated with storm restoration, with the exception of overtime costs and the costs to clear vegetation (e.g. trees, brush) from the storm-impacted distribution lines, are captured under this program. Overtime and forestry costs related to storm restoration are not capitalized, because these activities do not restore the capital assets to a better condition than existed before the storm, and provide no added benefit to future customers.

The funding level requested is based on an assessment of historical trends in costs and volume of work, taking into account any known factors that could impact historic trends.

The 2010 and 2011 spending requirements for this program are $59.3 and $59.2 million, which includes $28.4 million and $28.2 million for storm damage. These amounts are net of recoveries for third party damage and are consistent with projected expenditures in the bridge year. Proposed spending in the test years is based on a 4-year average of historical spending with adjustments made to incorporate recent trending in volumes and cost.

The overall program is currently seeing reductions in the need for emergency replacements with the exception of an increased need in submarine cable trouble calls. The reduction in trouble calls for poles and equipment are attributed to Hydro One Distribution’s investments and focus on activities such as wood pole and component replacements in recent years. Over the longer term, increased emphasis on submarine cable testing and refurbishment is expected to reduce the volume of emergency work required on cable plant. Planned asset replacement activities for wood poles, components, and submarine cables are discussed later in this schedule and in Investment Summary Documents in Exhibit D2, Tab 2, Schedule 2.

With respect to storm damage, variability in the number and severity of storms will impact expenditures from one year to the next. The 2010 and 2011 forecasts for storm damage of $28.4 and $28.2 million are lower than the 2006 and 2008 actual expenditures, which were $62.0 and $37.7 million respectively. As noted above and described in Exhibit A, Tab 15, Schedule 1, 2006 was an unusual year for storm damage with eight major (force majeure) storms, requiring an unprecedented 36 days of storm damage restoration. 2008 also experienced five major (force majeure) storm events including one large event. The majority of damage during storms continues to be attributed to falling trees and branches in close proximity to lines. These storms contributed from 24% to 75% of SAIDI over the historic years. Once a shorter vegetation management cycle is implemented, as discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2, it is expected that the customer outage durations and system vulnerability to storm damage, including the costs to repair storm damage, will diminish.

For additional details refer to the IJD in Exhibit D2, Tab 2, Schedule 3.

2.2.2 <u>Joint Use and Line Relocations</u>

<u>Joint Use</u>

The joint-use component of this program covers the work required to modify existing Hydro One distribution line assets to accommodate telecommunication or cable television lines, street lighting owned by municipalities, or power circuits for various Local Distribution Companies (LDCs).

Hydro One Distribution carries out joint-use projects in accordance with agreements between Hydro One Distribution and joint-use partners. The cost sharing provisions in these agreements allow Hydro One Distribution to recover its costs resulting from requests to add new attachments to poles. Historically, 25% to 35% of a joint-use project costs are recoverable. The recoverable portion represents the residual value of the line assets at the time the joint-use project is initiated plus the incremental cost for any modifications required for the new joint-use facilities. The unrecoverable portion of the costs recognizes that these projects generally result in increased life of the facilities that benefit Hydro One Distribution customers, due to a reduction of future investment needs.

All recoverable joint-use costs are paid by joint use partners at the time of the attachment. In addition, annual fees are levied per attachment to compensate for on-going incremental maintenance costs due to the presence of these attachments on the pole. Revenues associated with these annual fees are discussed in Exhibit E1, Tab 1, Schedule 2.

The joint-use program is driven by external demand for work, which Hydro One Distribution is required to provide in accordance with existing agreements. The number and size of joint-use projects in any given year can vary from 100 to over 200 projects with the scope of work typically costing less than $50,000 per project, although some projects can cost well in excess of that amount. The variation is predominantly due to activity at communication companies to enhance services to their customers.

Line Relocations

The line relocation component of this program covers the work required in response to road modifications initiated by Provincial and municipal road authorities, or by individuals who require assets relocated for the purpose of developing their property. Hydro One Distribution is obligated to relocate plant at customers' request in accordance with the requirements specified in its Conditions of Service. The relocation of plant to accommodate road modifications must be done in a timely manner as per the requirements of the Public Service Works on Highways Act, R.S.O. 1990, and associated

Ministry of Transportation guidelines. Relocations may entail the construction of new plant and the removal of old plant.

The cost of relocation projects is either fully or partially recoverable, depending on the specific circumstances of the project. Typically, a customer requesting a plant relocation must pay Hydro One Distribution for all costs incurred in moving the plant. In the case of projects associated with road relocations, the applicable statute provides guidance for cost allocations and typically Hydro One Distribution has recovered 20% to 35% of the total cost.

The number of relocation projects can vary significantly from year-to-year depending on the number of government infrastructure improvement projects and economic conditions influencing individual third party development projects.

Since the number and scope of individual joint-use and line relocation projects is variable, the total funding required is based on total historic costs, taking into account any observed trending and specifically identified joint-use or relocation work.

The 2010 and 2011 spending requirements for this program are $30.4 million and $30.5 million respectively, which is net of recoverable costs. These amounts are greater than the 2006 and 2007 actual expenditures but less than the 2008.

For additional details refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

2.2.3 Asset Replacement

Distribution lines asset replacement programs involve replacement of line components and line sections determined to be at end-of-life, and line modifications to address safety and reliability issues. These projects and programs are closely coordinated and integrated with System Capability Reinforcement plans (Exhibit D1, Tab 3, Schedule 3), where appropriate, in order to maximize the benefits of these expenditures.

The asset replacement work is divided into three programs with funding for the 2010 and 2011 test years, along with spending levels for the bridge and historic years, provided in Table 4 below.

Table 4
Asset Replacement
($ Million)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Wood Structure Replacement	30.3	40.1	43.0	42.2	46.4	59.0
Lines PCB Equipment Replacement*	0.2	0.1	0.6	1.4	0.7	3.1
Line Projects	17.0	19.8	20.4	30.4.	31.1	31.4
Total	**47.5**	**60.0**	**64.0**	**74.0**	**78.2**	**93.5**

*The 2007, 2008, and $1.4M of the 2009 amounts are attributed to the Waste Management Capital expenditures.

2.2.3.1 Wood Structure Replacement

The condition of wood poles deteriorates over time due to factors such as decay and rot, insect and rodent damage, or mechanical impact. When the condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions, poles are deemed to be at end-of-life and must to be replaced to ensure reliability and safety. Planned replacement of poles is less costly than "emergency" or reactive type replacements. Replacing defective poles on a reactive basis not only costs more than planned replacement due to increased labour costs (i.e. overtime premiums), but it also results in longer outage durations to customers and increased safety risks. There is a strong business need to replace substandard poles before they negatively impact the system and planned replacements are recognized as a good utility practice.

As discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2, Hydro One Distribution assesses poles as part of its routine line patrol activities and identifies poles that are in need of replacement. During the 2005 to 2008 period, approximately two thirds of the distribution system's 1.7 million poles were assessed and approximately 3% of the poles assessed were found to be in a sub-standard condition. The percentage of substandard poles on the system has remained relatively steady in recent years due to the efforts of the Wood Pole Replacement Program but is expected to rise given the demographics of the distribution system's pole plant. As such, it is important that the proposed end of life pole replacements be maintained, so as not to place added burdens on expected future increases in replacement. Details on pole demographics and pole replacement forecasts are provided in the Asset Condition Assessment and Analysis, Exhibit D1, Tab 2, Schedule 1.

In addition to concerns with demographics, Hydro One Distribution has recently identified a potential system-wide issue with a subset of red pine poles that were manufactured between 1997 and 2004. A number of these poles have failed during storm conditions and investigations have shown that these relatively young poles contained premature rot. There are approximately 55,000 poles that make up the subset that Hydro One Distribution is particularly concerned about. The deteriorating condition of these poles will place upward pressure on the numbers of sub-standard poles on the distribution system. Further details on this particular issue is also provided as part of the Asset Condition Assessment and Analysis, Exhibit D1, Tab2, Schedule 1.

The 2010 funding for this program will permit replacement of 7,500 poles which is a moderate increase from the 6,852 poles replaced in 2007, the 6,736 poles replaced in 2008, and the 7,000 poles planned for replacement in 2009. The increase of approximately 500 poles over 2009 will begin to address the issue identified with a subset of red pine poles. In 2011, the funding will permit further increases in replacements to 9,500 to address the premature decay of the red pine poles. This increase is prudent given the high degree of deterioration in red pine poles, which increase safety risks for joint use partners and Hydro One Distribution staff that have to work on these poles under difficult conditions (e.g. storms, power restoration). These risks need to be addressed in a proactive manner as they introduce work execution complexities that require added processes and training, thereby increasing overall costs.

Specific pole candidates for replacement in 2010 and 2011 will be identified through the pole assessment and testing program, which identifies poles that exhibit wood decay, checks and other defects that may jeopardize the structural integrity of a pole. The end-of-life determination for wood poles complies with the Canadian Standards Association (“CSA”) criteria for pole strength that specifies replacement when a pole has reached 65% of its original strength. This testing and replacement program maximizes reliability to customers, reduces public safety risks, complies with legal requirements and ensures optimal utilization of the wood pole population.

The 2010 and 2011 spending requirements for this program are $46.4 and $59.0 million which represent an increase over historic years. As discussed above, the increases are to replace a greater number of poles identified that are at end-of-life as found by the pole assessment program.

Reduced funding of the pole replacement program will increase reliability and safety risks and will prevent Hydro One Distribution from fully meeting due diligence obligations to remove known defective assets that present a hazard to workers and the public.

For additional details refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.2 Lines PCB Equipment Replacement Program

As discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2, new PCB regulations that were enacted in September 2008 require the retirement of equipment and insulating oil that contains PCBs in excess of 50 ppm. Hydro One Distribution has commenced a comprehensive equipment inspection and testing program to identify equipment that exceeds the 50 ppm threshold.

Once PCB contaminated equipment is identified, it is replaced through this program. In 2009, emphasis is being placed on pad-mounted transformers that exceed the 500 ppm threshold as the regulations require that these units be retired in 2009, resulting in an increase in 2009 expenditures. Beyond 2009, focus will shift to the retirement of contaminated equipment beyond 50 ppm beginning with pad-mounted transformers in 2010 and then pole mounted transformers and equipment beginning in 2011.

The spending requirements for 2010 and 2011 are $0.7 and $3.1 million respectively and represent funds directed to PCB equipment replacement only. The 2010 funds will replace 100 pad-mounted transformers and the 2011 funds increase in order to replace 650 pole and pad-mounted transformers along with 70 capacitors. Transformers with oil with PCB content above 50 ppm are identified under the inspection and testing program described in Exhibit D1, Tab 2, Schedule 2, Section 2.2.3.2.

It should be noted that funds appearing under this program in 2007, 2008, along with $1.4 million in the bridge year (i.e. 2009) were directed to waste management capital and the replacement of waste storage containment tanks. Funds for Waste Management are not required over the 2010 to 2011 period given that all containment tanks requiring replaced will have been replaced by the end of 2009. The nature and the need of the work in the test years is substantially different than in the past, and as such a direct comparison of proposed spending levels to historical spending is not appropriate.

For additional details refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

2.2.3.3 Line Projects

This program funds the refurbishment of entire feeders or sections of a feeder when the cost of maintaining individual components in the circuit becomes excessive, or a number of components have reached, or are near end-of-life, jeopardizing the reliability of the electrical supply. A decision as to the most appropriate course of action is made in each case taking into account overall condition of poles, wire and cables, condition of associated components, access for maintenance and repair, current and future load requirements and environmental considerations. These projects are further integrated with any system capacity reinforcement plans for the area.

Additional projects funded under this program address safety hazards and environmental issues. Specific projects in this category involve the replacement of submarine cable where the concentric neutral wires have corroded and present a hazard to the public, as well as line modifications to correct hazardous water crossings. The program also funds structural modifications required to accommodate osprey nesting sites where the location of the nest may cause power interruptions.

In addition to the projects noted above, this program funds the replacement of individual line components such as switches, reclosers and wood arms that have been determined to be defective.

The 2010 and 2011 spending requirements for this program are $31.1 and $31.4 million respectively. The increases over bridge year and historical spending are due to the two items described below, both of which are attributed to ageing plant and deteriorating conditions that ultimately pose unacceptable safety and reliability risks:

1) Submarine Cable Refurbishment – As detailed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2 and Asset Condition Assessment Exhibit D1, Tab 2, Schedule 1, ageing submarine cables corrode as they age and can pose serious public safety hazards. Hydro One Distribution's condition assessment activities, including the new submarine cable testing program, have identified a large number of cables that require refurbishment. In particular, cables assessed using the new testing procedure are failing one out of every six to seven times. This equates to a 15% failure rate and is driving the need for increased numbers of submarine cable refurbishment. Refurbishments can take the form of entire cable replacement or the replacement of short sections around the shorelines of water bodies. Depending on the refurbishment option, the length of the cable, and the cable location's terrain, geography, and access points, the cost of a refurbishment can vary significantly. Proposed increases to fund submarine cable replacements make up approximately one third of the increase in overall Line Projects funding.

2) Large Sustaining Projects – Historic accomplishment levels are not enough to keep up with the deterioration of the lines system as identified through the ACA process. The alternatives would be to replace individual defective assets on a component basis or to wait until components fail in service and replace them on a reactive basis, at a premium cost and with increased safety risks. To avoid these alternatives, proposed increases to funding in this area are required, which contribute up to 50% of the increase in overall Line Projects funding. It should be noted that individual projects can vary significantly in size and scope (e.g. from $250 thousand per project to over $2.5 million) depending on the nature of the work. Examples of the factors that can drive cost variability include off-

road feeder sections, line sections with multiple circuits on one pole line, and the presence of submarine cables or water crossings.

For details concerning specific projects to be completed over the test years with a value of $1 million or greater, including those for submarine cables and Large Sustaining Projects, please refer to the ISDs S11 to S29 in Exhibit D2, Tab 2, Schedule 3.

2.3 Meters

Meter capital addresses spending requirements for customer retail meter upgrades and conversions. Funding for the meters program for 2010 and 2011, as well as spending in the bridge and historic years, are provided in Table 6 below.

Table 6
Metering Capital
($Million)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Customer Retail Meters	1.6	0.4	1.0	1.6	3.8	4.1
Total	**1.6**	**0.4**	**1.0**	**1.6**	**3.8**	**4.1**

2.3.1 Customer Retail Meters

The sustaining capital retail meter program includes meter upgrades, conversions of meters and meter bases, and the sustainment of the retail meter inventory. Each of these categories of work are outside the scope of the Smart Meter Program and are discussed below.

<u>Meter Upgrades</u>

Hydro One Distribution upgrades and replaces meters due to a variety of drivers. One driver is related to the Distribution System Code, which requires an existing customer's demand meters to be upgraded to interval meters when the average annual monthly peak demand is equal to or greater than 1,000 kW. A second driver is the need to upgrade a small number of non-standard meters at acquired LDCs to enhance maintenance efficiency. Other drivers include the need to install demand meters for customers who exceed 150,000 kWh of energy consumption per year and the modification of wholesale meters used by customers that did not decide to register with the IESO to participate in the wholesale market but instead chose to become retail customers of Hydro One Distribution. In total, the spending for these meter upgrades and modifications is $0.7 million in 2010 and $0.9 million 2011.

<u>Meter Conversions</u>

Meter conversions encompass three programs. The first is a new three year program that is starting in 2010 to replace about 7,500 "dumb" demand meters with electronic demand meters that have communication capability. This will eliminate manual meter reading, standardize inventory, and increase efficiency in dealing with trouble calls and maintenance due to reduced number of meter types. The cost for this program is $1.3 million in 2010 and $1.7 million in 2011. For additional details concerning this program, refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

The second conversion project is related to approximately 71,000 legacy meters with 4 jaw bases that are eligible for a Smart Meter replacement. Smart Meters require 5 jaw bases. The lowest cost method to accommodate this requirement is with a 4 to 5 jaw adaptor. A program to install these adapters began in 2009 and will continue to completion in 2010. The cost for this is $1.3M in 2010. For additional details concerning this program, refer to the ISD in Exhibit D2, Tab 2, Schedule 3.

The third conversion project is related to approximately 1,000 600V self contained meters which require replacement. A number of these 600V meters have expired seals and are on an overdue list with Measurement Canada as there were no available new, sealed meters to use in like-for-like replacement. Only recently has one manufacturer made available a like-for-like replacement. There is also an increased safety risk in resealing 600V self-contained meters when compared to 120V transformer rated meters. Replacing these 600V meters with an inherently safer 120V unit increases employee and customer safety, allows Hydro One Distribution to meet expired seal obligations, eliminates a reliance on a single source supply, and allows for a more efficient and reduced stock requirement. The cost for this program is $0.5M in 2010 and $0.8 million in 2011.

Sustainment Program

The Retail Meter Inventory Sustainment Program is required in order to efficiently replace in-service meters that fail, are obsolete, or that cannot be returned to service through the re-verification program. A historic annual level of approximately 2,000 new meter purchases ended in 2008, as the Smart Meter Program has been covering the cost of replacing failed or obsolete meters. However, about 80,000 meters which do not qualify for smart meter replacement, still require an adequate inventory, with about 100 new meter purchases required per year. The total spending for this initiative during 2010 is $0.1 million. In 2011, the inventory required to replace failed Smart Meters begins to ramp up and the expenditure level increases to $0.6 million.

In total, the 2010 and 2011 spending requirements for this program are $3.8 million and $4.1 million respectively. These requirements are greater than historic and bridge years primarily as a result of meter conversion projects described above.