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RATE BASE

Rate Base Overview

The rate base underlying the revenue requirement sought in this Application has been determined on a basis consistent with the definition in the 2006 Electricity Distribution Rate ("EDR") Handbook. The rate base used to determine the revenue requirement is defined as net fixed assets calculated as an average of the balances at the beginning and the end of each Test Year, plus a working capital allowance.

The net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. OPUCN does not have any non-distribution assets.

Controllable expenses include operations, maintenance, billing and collecting, and administration expenses.

The working capital allowance is 13% of the sum of the cost of power and controllable expenses based on OPUCN's Lead/Lag Study provided below.

Where applicable, OPUCN has adopted the policies provided in the Board's report dated January 15, 2010 entitled – *The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors* – to identify: construction work in progress that OPUCN believes should be considered in its rate base; and Green Energy Act-related investments that accommodate the connection of renewable generation or to develop and implement a smart grid.

Modified International Financial Reporting Standards ("IFRS")

The Board issued a report in July 2009 with guidance on IFRS within the regulatory environment entitled – *Report of the Board on the Transition to International Financial Reporting Standards* (EB-2008-0408). The Board also issued a clarification letter regarding the capitalization of overhead costs in February 2010. A Board sponsored depreciation study was issued in July of 2010. On November 8, 2010, an amendment to the July report was issued to address the delay in implementing IFRS until January 1,

2012. A letter was also issued on March 15, 2011 to address the use of IFRS in cost of service applications for 2012 rates. Lastly an *–Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2008-0408) – was issued on June 13, 2011. Collectively this set of guidance is referred to as the Board's IFRS Guidance throughout this exhibit. The Board's IFRS Guidance uses the term Modified IFRS ("MIFRS") to refer to IFRS accounting, as modified by the Board for regulatory purposes.

In a letter dated March 15, 2011 and subsequent EB-2008-0408, – Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment – issued on June 13, 2011, the Board directions were updated to include, among other items, the following:

"Electricity distributors filing cost of service applications for rates for 2012 should make all reasonable efforts to provide the forecasts for the 2012 test year in modified IFRS accounting format. In addition, the electricity distributor must provide the required actual years, the bridge year, and the forecasts for the test year(s) in CGAAP-based format..."

OPUCN's 2012 cost of service application, *EB-2011-0073*, was prepared in compliance with the Board's Guidelines for MIFRS noted above.

Upon OPUCN's transition to reporting under MIFRS in 2012, there is no requirement for comparative Canadian Generally Accepted Accounting Principles amounts. As a result all balances included in this Application have been determined under MIFRS.

Rate Base

OPUCN has provided a summary of its rate base calculations for the: 2012 Board Approved amount; 2012 and 2013 actual results; and forecast 2014 Bridge Year, and 2015 through 2019 Test Years in Table 2-1 below. Table 2-2 calculates the variances from year to year.

TABLE 2-1 - SUMMARY OF RATE BASE

Account Description	Board-Approved	Actual		Bridge Year	Test Years at Proposed Rates				
	2012	2012	2013	2014	2015	2016	2017	2018	2019
Opening Fixed Assets, Net Book Value	60,896,584	61,933,453	69,526,603	76,200,678	83,418,175	92,040,040	98,554,606	105,743,420	112,613,084
Closing Fixed Assets, Net Book Value	68,036,873	69,526,603	76,200,678	83,418,175	92,040,040	98,554,606	105,743,420	112,613,084	117,622,147
Average Fixed Assets, Net Book Value	64,466,729	65,730,028	72,863,640	79,809,426	87,729,108	95,297,323	102,149,013	109,178,252	115,117,616
Cost of Power	97,524,785	96,181,988	102,012,056	112,530,041	120,634,817	122,428,838	123,586,740	124,964,741	125,921,985
Operation Expenses	982,254	1,167,906	919,397	1,025,060	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
Maintenance Expenses	1,409,450	1,094,190	1,313,715	1,311,703	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
Billing and Collecting Expenses	2,433,401	2,398,127	2,462,960	2,594,648	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
Administrative and General Expenses	6,505,765	6,430,919	6,361,731	6,204,724	6,699,898	6,877,527	6,942,612	7,079,635	7,219,041
Taxes Other than Income Taxes	149,350	149,309	152,292	155,338	158,445	161,613	165,007	168,473	172,010
Working Capital	109,005,005	107,422,438	113,222,151	123,821,514	132,780,518	135,043,042	136,473,428	138,074,546	139,105,474
Working Capital Allowance Rate	15.0%	15.0%	15.0%	15.0%	13.0%	13.0%	13.0%	13.0%	13.0%
Working Capital Allowance	16,350,751	16,113,366	16,983,323	18,573,227	17,261,467	17,555,595	17,741,546	17,949,691	18,083,712
Rate Base	80,817,479	81,843,394	89,846,963	98,382,653	104,990,575	112,852,919	119,890,558	127,127,943	133,201,327

TABLE 2-2 - VARIANCES IN YEAR OVER YEAR RATE BASE

Account Description	2012 Actual to 2012 Board-Approved	2013 Actual to 2012 Actual	2014 Bridge Year to 2013 Actual	2015 Test Year to 2014 Bridge Year	2016 Test Year to 2015 Test Year	2016 Test Year to 2015 Test Year	2016 Test Year to 2015 Test Year	2016 Test Year to 2015 Test Year
Opening Fixed Assets, Net Book Value	1,036,869	7,593,150	6,674,075	7,217,497	8,621,866	6,514,565	7,188,814	6,869,664
Closing Fixed Assets, Net Book Value	1,489,730	6,674,075	7,217,497	8,621,866	6,514,565	7,188,814	6,869,664	5,009,063
Average Fixed Assets, Net Book Value	1,263,299	7,133,612	6,945,786	7,919,681	7,568,216	6,851,690	7,029,239	5,939,364
Cost of Power	(1,342,798)	5,830,068	10,517,985	8,104,776	1,794,021	1,157,902	1,378,000	957,244
Operation Expenses	185,652	(248,509)	105,663	262,959	196,129	109,350	(14,353)	(168,631)
Maintenance Expenses	(315,260)	219,525	(2,012)	34,576	29,236	29,954	30,608	31,276
Billing and Collecting Expenses	(35,274)	64,833	131,688	58,414	62,339	64,701	66,374	68,096
Administrative and General Expenses	(74,846)	(69,187)	(157,008)	495,174	177,629	65,085	137,023	139,405
Taxes Other than Income Taxes	(41)	2,983	3,046	3,107	3,169	3,394	3,465	3,538
Working Capital	(1,582,567)	5,799,713	10,599,363	8,959,005	2,262,523	1,430,387	1,601,118	1,030,928
Working Capital Allowance	(237,385)	869,957	1,589,904	(1,311,760)	294,128	185,950	208,145	134,021
Rate Base	1,025,914	8,003,569	8,535,690	6,607,922	7,862,344	7,037,640	7,237,385	6,073,384

OPUCN's rate base is forecast to be $105.0 million in the 2015 Test Year; $24.2 million higher than the Board-Approved 2012 rate base totaling $80.8 million. This represents an increase of 30% over a three year period.

Average net fixed assets increased by $23.3 million while working capital allowance increased by $0.9 million.

The rate applied to OPUCN's working capital was reduced from 15% in 2012 to 13% in 2015 resulting from the Lead/Lag Study obtained from a third-party and provided below.

The impact of the rate reduction on 2015 working capital allowance is estimated to be $2.7 million which was offset by $3.6 million related to increases in cost of power and controllable expenses. Cost of power has increased by $23.1 million (23.7% over the period) while controllable expenses increased by $0.7 million or 5.8% (cumulative average annual increase of 1.9%). Forecast demand and consumption are approximately the same as the Board-Approved amounts in 2012; the increases to cost of power are related to increases in applicable rates (cumulative average annual increase of 7.3%).

The requirement for large capital expenditures experienced by OPUCN, which is the key driver for the increase in its 2015 rate base, was outlined in the cost of service rate application filed with the Board in 2011 for rates beginning in 2012. The following highlighted material was copied from the rate application as filed.

> *OPUCN's capital investment in its distribution plant has averaged approximately $5 million per year over the past 10 years. By comparison, OPUCN estimates that it will require average capital expenditures of approximately $12 million over the next five years, beginning with 2011. As presented in the Asset Condition Assessment and Asset Management Plan ("Asset Management Plan") prepared by Metsco Energy Solutions filed as Appendix A to this Exhibit, this level of investment is required to upgrade the Company's assets which are near or at the end of their useful lives and to ensure the City of Oshawa continues to receive safe and reliable power in the future.*
>
> *A summary of the expected capital expenditures over the next five years is presented in the table that follows:*
>
> - *2011 – $10,740,059*
> - *2012 – $11,122,343*
> - *2013 – $11,885,858*
> - *2014 – $13,594,095*
> - *2015 – $13,312,993*

The total in-service capital expenditures for the five year period presented in the 2012 cost of service rate application was $60 million and did not include the investment in smart meters. Based upon actual expenditures on in-service capital for 2011 through 2013 (net of smart meters) plus forecast 2014 and 2015, the total spend is expected to be $58.

Total planned in-service capital expenditures outlined in OPUCN's 2012 cost of service application are in line with actual expenditures for 2011, 2012 and 2013 plus forecast 2014 and 2015 amounts. The investment in smart meters was excluded from the comparison due to the special circumstances in reporting the expenditures and recognition was subject to a separate Board review and Decision.

The requirement for in-service capital expenditures outlined in OPUCN's 2012 cost of service application was acknowledged by the Board as evidenced in their decision to: approve $10.2 million for 2012; and, additionally, approve an Accounting Order for an asymmetrical variance account to capture the difference between actual capital expenditures and the Board-Approved amount in the event the actual amount is lower.

The following has been copied from OPUCN's Draft Rate Order dated December 13, 2011:

Issue 2.3, "Are the capital expenditures appropriate?"

On page 11 of the Settlement Agreement, the Parties agreed that the resulting forecast of 2012 Test Year capital expenditures is appropriate. However, in the event that actual capital expenditures are less than the amount forecast, the Parties have agreed that it is appropriate to establish an asymmetrical variance account ("Capital Additions Variance Account") that would provide for the return to customers of the revenue requirement impact related to the difference between $10.2 million (under IFRS) of capital expenditures, and actual 2012 capital expenditures, if lower.

The Capital Additions Variance Account would record the difference in all components of annual revenue requirement (including, but not limited to, depreciation, interest, return on equity and PILs) resulting from any under spending on total capital expenditures closed to rate base in the Test Year. That is, if the capital expenditures are less than $10.2 million, the revenue requirement impact of the shortfall will be calculated and credited to the account. The account would be subject to disposition in accordance with the Board's normal policies from time to time on the disposition of applicable variance accounts.

In addition, the *Transcript Oral Hearing 20111206* filed on December 6, 2011 relating to the 2012 cost of service application included recordings of: a discussion regarding capital expenditure requirements for the years 2013 through 2015; and mechanisms to ensure OPUCN investments in its capital expenditures met its planned spend included in the table above.

The applicable recordings can be found on pages 6 through 15 of the *Transcript Oral Hearing 20111206* filed on December 6, 2011.

In addition to the level of in-service capital expenditures required to ensure the continued operational viability of OPUCN's distribution system, the annual cash investments in capital expenditures have been significantly more than the depreciation expense reported over the same period.

The following table provides the comparison between capital expenditures and depreciation expense for the period in millions of dollars:

TABLE 2-3 - COMPARISON BETWEEN CAPITAL EXPENDITURES AND DEPRECIATION

	2012 Approved	2012	2013	2014	2015
Capital	$ 10.2	$ 11.1	$ 10.7	$ 11.7	$ 13.5
Depreciation	$ 3.1	$ 3.3	$ 3.9	$ 4.1	$ 4.5
Difference	$ 7.1	$ 7.8	$ 6.8	$ 7.6	$ 8.9
Multiple	3.3	3.7	2.7	2.9	3.0

This pattern of high capital expenditures relative to lower depreciation expense results in the increase in net fixed assets driving the increase in rate base provided in Table 1. The variances in OPUCN's rate base for the 2016 to 2019 Test Years are summarized as follows:

- The 2016 Test Year rate base is calculated as $112.9 million, a $7.9 million, or 7.5% increase over the 2015 Test Year rate base.
- The 2017 Test Year rate base is calculated as $119.9 million, a $7.0 million, or 6.2% increase over the 2016 Test Year rate base.
- The 2018 Test Year rate base is calculated as $127.1 million, a $7.2 million, or 6.0% increase over the 2017 Test Year rate base.
- The 2019 Test Year rate base is calculated as $133.2 million, a $6.1 million, or 4.8% increase over the 2018 Test Year rate base.

The variances summarized above highlights the need for OPUCN to file its rate application for the period under the Custom Incentive Rate-Setting mechanism identified in the Report of the Board, ***Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach ("RRFE")***, issued on October 18, 2012.

Under Section 2.2.1 of the RRFE, the Board made the following statements:

"In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The

Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels."

The significant driver for the Custom IR approach to rate-making is OPUCN's requirement for large multi-year investments in capital expenditures. Based upon OPUCN's Distribution System Plan included in Chapter 5 of this rate application, annual capital expenditures and the applicable Depreciation Expenses are presented in the following table:

TABLE 2-4 - COMPARISON BETWEEN CAPITAL EXPENDITURES AND DEPRECIATION

	Test Years				
	2015	2016	2017	2018	2019
Capital Expenditures	13,509,900	11,627,000	12,372,000	12,476,000	10,761,000
Depreciation Expense	4,491,588	4,847,338	5,000,972	5,203,071	5,370,697
Multiple	3	2	2	2	2

The pace of capital expenditures continues to be approximately two to three times the level of annual depreciation expense which places financial pressure on OPUCN's ability to generate reasonable returns on its deemed equity unless rates are adjusted in accordance with the Custom IR approach. In addition to the lag on returns associated with the capital expenditures, the annual increase in depreciation expense out paces the increase in operating revenue received under an IRM rate regime.

Net Capital Additions – 2012 to 2019

The increase in net capital additions from OPUCN's 2012 Board-Approved to the 2019 Test Year is principally the result of necessary rising investment in the renewal of distribution assets at or near end-of-life for the years 2012 through 2014; expansion requirements and capacity constraints relating to higher than normal expected customer growth; and, to a lesser extent distribution automation and new technology. OPUCN identified the need for careful planning, review, and prioritization of the increased asset investment in its 2012 cost of service application as noted above.

As described in OPUCN's Distribution System Plan, Chapter 5, OPUCN's capital expenditures over the period 2011 -2019, are summarized below and listed in the elements prescribed by the OEB.

TABLE 2-5 – CAPITAL EXPENDITURES 2011 TO 2019 ($'000S)

CATEGORY	Historical Period (previous plan[1] & actual)					Forecast Period (planned)				
	2011	2012		2013	2014	2015	2016	2017	2018	2019
	Actual	Plan	Actual	Actual	Bridge[2]					
	$ '000	$ '000		$ '000	$ '000	$ '000				
System Access	8,913	2,609	2,899	4,042	3,867	8,995	4,140	3,550	3,435	3,455
System Renewal	7,039	7,037	7,162	5,971	5,958	4,883	4,932	4,472	4,761	4,851
System Service	0		0	1,903	2,830	2,868	2,830	4,670	4,645	3,050
General Plant	1,476	1,500	2,302	530	634	1,675	1,180	755	730	510
TOTAL EXPENDITURE GROSS	17,428	11,146	12,363	12,446	13,289	18,421	13,082	13,447	13,571	11,866
Less 3rd Party Contributions	(931)	(931)	(1,271)	(1,699)	(1,560)	(4,911)	(1,455)	(1,075)	(1,095)	(1,105)
TOTAL EXPENDITURE NET	16,497	10,215	11,092	10,747	11,729	13,510	11,627	12,372	12,476	10,761

System Access: Non-discretionary investments related to customer service connections, third party requests for plant relocations, metering and regulated mandatory requirements.

Third Party requests for Plant Relocation

During 2011 to 2014, OPUCN worked collaboratively with the City of Oshawa and the Durham Region to relocate its distribution plant to accommodate roadway reconstruction.

In 2014, the Eastern Construction General Partners (ECGP) started the extension of the Highway 407 with the expected opening in 2015. Gross expenditure of approximately $5.1 million was planned for 2014 and relates to OPUCN's plant relocation to accommodate the Highway extension. However delays in the ECGP's construction has extended this work into 2015, and the Net expenditures will then be accounted. As the ECGP is responsible for "like for like" relocation costs, OPUCN's Net capital is estimated to be $1.3 million to cover infrastructure required for future services.

Similarly, in 2014, plant relocation related to the Region of Durham's and the City of Oshawa's road widening projects is approximately $380 thousand gross (Net $250 thousand) and $430 thousand gross (Net $300 thousand) respectively.

Over the period 2015-2019, OPUCN forecasts gross expenditures of approximately $13.9 million (Net $7.7 million) in third party relocation requests (that is 407, Durham Region and City of Oshawa).

Expansions and Service connections

Customer connections and subdivision expansions have been steadily increasing from 2011 to 2014. The City of Oshawa, with their aggressive marketing and developmental incentives, has attracted significant residential and business development. Based on the City's forecasted data, OPUCN has projected accelerated customer growth of approximately 3% annually in Oshawa, over the period 2015 – 2019, with forecasts of approximately $6.3 million Gross (Net $3.5 million) of expenditures related to subdivision expansions and service connections.

<u>Metering</u>

Over the period 2015 – 2019, the total associated metering installation related to service connection activities and meeting OEB's mandatory requirements is projected to be approximately $3.4 million.

System Renewal - Renewal of Distribution Assets primarily identified by the Asset Condition Assessment, operational inspection and testing reports, primary cable fault analysis and maintenance reports

In 2013, OPUCN retained a third party consultant (METSCO Energy Solutions) to complete an Asset Condition Assessment (ACA) on OPUCN major assets (e.g. substations, Overhead and Underground plant) to determine the overall condition of its distribution system plant. METSCO also prepared a five year Asset Management Plan (AMP) based on the asset's condition, age, optimal operating conditions, end of useful service life and financial or budget consideration. This Plan identifies critical or poor assets that are at the end of their useful life and need to be replaced to avoid unacceptable risk of in service failure. OPUCN used METSCO's ACA report and AMP as a major guideline to define necessary rebuild projects or plant upgrades under the system renewal investments. METSCO's Asset Condition Assessment Report and Asset Management Plan is attached separately as an appendix of the DS Plan.

These renewal projects will improve OPUCN's system reliability and resilience, mitigate outage impacts to customers, address safety related issues or upgrade old plant to meet new standards due to materials/equipment being obsolete.

In 2011 - 2013, OPUCN replaced the following major critical assets in addition to required overhead and underground rebuilds:

- Four municipal stations rebuilds (MS2, MS15, MS13 and MS5) involving the replacements of eight power transformers, related underground and overhead

44kV infrastructure replacements; relays and breakers replacements (~ $7.0 million);

- Four Underground transformer vault rebuilds with associated equipment upgrades, - Bond St, Simcoe St, Athol St, Regent Theatre and William Vault (~$1.5 million);

In 2014, replacement of overhead and underground rebuilds including station power transformer replacement (MS5) and replacement of MS14 switchgear. Forecast total is ~$6 million.

System Service (~$2.8 million):

- To address load growth in Oshawa and resulting capacity constrains at both Wilson and Thornton transmission stations (TS) –overhead extension and upgrades of primary feeders to allow switching flexibility and system load balancing between Wilson and Thornton TS (~$1.8 million).
- Underground downtown vault automation to enhance system reliability and resiliency (a “smart grid” project) (~$1 million).

Over the period 2015 - 2019, OPUCN renewal of assets will be more of a sustaining approach, with an average annual expenditure as follows:

- Overhead rebuilds approximately $2.3 million
- Underground rebuilds approximately $1 million
- Stations rebuilds approximately $630 thousand. Couple of anomalies to note and that is in 2015, major expenditures of #1.5 million will be accounted for to cover the replacement of MS14’s metal clad 13.8kV switchgear and associated lead primary cables that reached end of life. This MS14 switchgear project started in 2014 and will be commissioned and placed in service in 2015. (~$2 million). Also, in 2019, MS5 T2 transformer unit is proposed to be replaced as this transformer unit is greater than 30 years and has now started to show

moderate increase in combustible gas levels. It is not significant at this time and we will be constantly monitoring this to avoid major in service failure. (~$1 million)

Overall the total expenditures for system renewal over the 2015 – 2019 period is approximately $23.9 million which includes unplanned emergency type replacements of $4.2 million.

System Service – Investments to address system capacity constraints and grid modernization:

Prior to 2011, Oshawa's load growth did not warrant the need to rebuild or extend its distribution plant to facilitate load transfers in between transmission stations. With the promotion of the Highway 407 extension into Oshawa, subdivision activity started to increase, and in 2012, discussions resurrected with HONI to review station capacity at both Wilson TS and Thornton TS. Over the period 2013-2014, OPUCN completed approximately $3.8 million in major overhead expansions and rebuilds as part of its initial collaborative solution with Hydro One Transmission and Distribution. These investments were triggered by stations capacity constraints at Wilson TS and subsequent Hydro One's suggestion to OPUCN to transfer load from Wilson TS to Thornton TS given that this station had available capacity. OPUCN's load transfer from Wilson TS to Thornton TS provides the required initial relief at Wilson TS to accommodate ongoing load growth from accelerated subdivision development activity and customer connections.

During this 2013 – 2014 period, OPUCN also invested approximately $0.9 million in modernizing its grid with automated intelligent devices and equipment to allow OPUCN to have faster restoration times, reduce outage duration to customers and improve overall system reliability.

Going forward in 2015 – 2019 and based on the projected load growth in Oshawa (along with future load projections from other affected local distribution utilities) there is need for transmission station capacity relief at both Wilson TS and Thornton TS.

Regional Planning discussions are in progress including Local Planning meetings to address both Station and feeder capacity constraints. Original discussions with Hydro One Transmission suggested a preliminary Contribution from OPUCN to HONI of approximately $6.5 million to cover the provision of two 44KV feeder positions at both Wilson TS and Thornton TS. This amount is included in OPUCN 5 year plan and smooth out to minimize rate impact. Recent regional meetings with HONI Tx and Dx, and impacted LDCs suggest the construction of a new 230kV/44kV transmission station (Enfield TS) to be the permanent solution to address the station capacity issues at Wilson and Thornton TS. This option is still under discussion and if implemented will increase OPUCN's contribution from $6.5 million to potentially $10 million to $12 million.

Furthermore, Local Planning meetings are now being conducted separately from the Regional Planning process to resolve feeder capacity issues at Thornton TS. Options are still being reviewed and are not yet finalized but will now have an additional cost that will now be covered through the initial $3 million included in the 5 year plan to address Thornton Capacity issues.

As a result of the accelerated development activity and customer connections over 2015- 2019, OPUCN has identified the need to construct a new municipal substation (MS9) with appropriate associated distribution feeders to service these new homes and retail or commercial premises. The approximate total cost for this 4 year project is $9 million.

Grid Modernization - OPUCN is continuing to move forward with its plan to increase the installation of automated and self-healing devices and equipment to allow remote automated switching and fault isolation to reduce restoration time and outage impact to customers.

Advanced technology with intelligent devices and management systems will enable OPUCN to operate a “smarter grid” that will have better visibility and operational flexibility to not only minimize outage impacts, but will also identify areas to achieve grid performance by improving line losses, and managing peak consumption to reduce transmission charges and resulting customers' electricity costs.

Over the next 5 years (2015-2019), OPUCN forecasts approximately $2.6 million of capital spend in grid modernization

General Plant: Investments in this category include day to day business and operational support including non-system physical plant:

- Fleet
- Facilities
- Major Tools and equipment
- Office IT Software and hardware Upgrades
- Operational software & systems (e.g. Outage Management System (OMS), Mobile Work force system (MWF), Operational Data Storage (ODS), Geographical Information System (GIS), Customer Information System (CIS), Automated Meter Information (AMI), Interactive Voice Response (IVR)

In 2011 - 2014, significant investments of approximately $4.9 million included:

- vehicle replacements
- enhancements in AMI, ODS and GIS and telephone systems
- facilities or leasehold improvements.
- software solutions that would improve and sustain GIS data connectivity accuracy, which is critical for OMS implementation. OPUCN is scheduled to have a vendor selection by end of 2014 and a system installation start date early 2015.
- IT security software and hardware including a Disaster Recovery data backup system to cover production site server failures or damages.

In 2015-2019, OPUCN total overall general plant expenditures are approximately $4.9 million to cover the completion and in-service of a fully integrated OMS solution with SCADA, GIS, AMI, CIS, IVR plus ongoing system enhancements (~1.9M); fleet replacements (~$1.6 million), facilities, tools and equipment (~$0.7 million) and Server upgrades that has reached its end of life (~$0.7 million).

WORKING CAPITAL ALLOWANCE

OPUCN engaged Ernst and Young LLP ("E&Y") to undertake its Lead/Lag Study; which is the principal basis for its proposal for working capital allowance. In this application, based on the work completed by E&Y, OPUCN submits that 13% is the appropriate statistic applied to operating, maintenance and administrative ("OM&A"), and cost of power for the purpose of calculating the working capital allowance commencing in 2015. This represents a decrease of 2% from the 15% rate for working capital allowance that the Board approved in its Decision in OPUCN's 2012 cost of service application.

OPUCN's proposed working capital allowance for each of the Test Years is:

- 2015 – $17,261,467
- 2016 – $17,555,595
- 2017 – $17,741,546
- 2018 – $17,949,691
- 2019 – $18,083,712

RATE BASE VARIANCE ANALYSIS

Section 2.4.5 of *Filing Requirements For Electricity Distribution Rate Applications – 2014 Edition for 2015 Rates Applications* – ("Filing Requirements") set out the methodology for calculating the materiality threshold that distributors are to use to explain year over year variances exceeding this threshold for rate base, capital expenditures and OM&A.

The Filing Requirements state the relevant default materiality threshold as, "0.5% of operating revenue for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million."

OPUCN's revenue requirement exceeds $10 million and is less than $200 million and as such the materiality threshold is calculated as 0.5% of the Company's operating revenue. With an operating revenue requirement ranging from $18.1 million and $25.9 million, OPUCN has calculated a materiality threshold ranging from approximately $90,000 to $130,000, as reported in the following table.

TABLE 2-6 – MATERIALITY THRESHOLD

	At Board-Approved Rates				Test Years at Proposed Rates				
	2012 Board-Approved	2012 Audited	2013 Audited	2014 Bridge Year	2015	2016	2017	2018	2019
Total Distribution Revenue	20,043,142	19,842,114	19,859,729	19,503,876	22,901,583	25,054,593	26,022,430	27,057,622	27,711,474
Other Distribution Revenue	(1,792,057)	(2,030,035)	(1,934,649)	(1,390,271)	(1,336,319)	(1,506,940)	(1,631,192)	(1,452,379)	(1,517,631)
Operating Revenue	18,251,085	17,812,079	17,925,081	18,113,604	21,565,264	23,547,653	24,391,239	25,605,243	26,193,843
Materiality Threshold Rate	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Materiality Threshold	91,255	89,060	89,625	90,568	107,826	117,738	121,956	128,026	130,969

In an effort to provide a thorough and relevant analysis OPUCN has used a materiality threshold of $100,000 throughout this Application.

2012 Actual Comparison to 2012 Board-Approved Rate Base

The actual rate base of $81,843,394 for 2012 was higher than the Board-Approved 2012 amount by $1,025,914 due to an increase in average net fixed assets of $1,263,299 partially offset by lower working capital allowance of $237,384.

The following table provides the variance calculations:

TABLE 2-7 – 2012 ACTUAL COMPARISON TO 2012 BOARD-APPROVED RATE BASE

Account Description	Board-Approved	Actual	Variance	
	2012	2012	$	%
Opening Fixed Assets, Net Book Value	60,896,584	61,933,453	1,036,869	1.7%
Closing Fixed Assets, Net Book Value	68,036,873	69,526,603	1,489,730	2.2%
Average Fixed Assets, Net Book Value	64,466,729	65,730,028	1,263,299	2.0%
Cost of Power	97,524,785	96,181,988	(1,342,798)	-1.4%
Operation Expenses	982,254	1,167,906	185,652	18.9%
Maintenance Expenses	1,409,450	1,094,190	(315,260)	-22.4%
Billing and Collecting Expenses	2,433,401	2,398,127	(35,274)	-1.4%
Administrative and General Expenses	6,505,765	6,430,919	(74,846)	-1.2%
Taxes Other than Income Taxes	149,350	149,309	(41)	0.0%
Working Capital	109,005,005	107,422,438	(1,582,567)	-1.5%
Working Capital Allowance	16,350,751	16,113,366	(237,385)	-1.5%
Rate Base	80,817,479	81,843,394	1,025,914	1.3%

The variance increase in the average net fixed assets 2012 Actuals compared with 2012 Board Approved of $1,263,299 is primarily due to more than planned emergency replacements of overhead plant; unplanned purchased of cameras installed in substations for security reasons and unplanned system software and licence expenses.

The actual working capital allowance was lower than Board-Approved due to lower cost of power ($1,342,798) and lower OM&A expenses ($239,770).

Actual cost of power was lower than Board-Approved because actual consumption was approximately 2% lower as a result of fewer customer connections (1,627 fewer average connections) and a declining average consumption per customer connection.

OM&A expenses were lower primarily due to lower labour costs of approximately $110,000 and provision for bad debts totalling $140,000.

2013 Actual Comparison to 2012 Actual Rate Base

The actual rate base of $89,846,963 for 2013 increased by $8,003,569 compared to 2012 actual. Average net fixed assets increased by $7,133,612 and working capital allowance of $869,957.

The following table provides the variance calculations:

TABLE 2-8 – 2013 ACTUAL COMPARISON TO 2012 ACTUAL RATE BASE

Account Description	Actual		Variance	
	2012	2013	$	%
Opening Fixed Assets, Net Book Value	61,933,453	69,526,603	7,593,150	12.3%
Closing Fixed Assets, Net Book Value	69,526,603	76,200,678	6,674,075	9.6%
Average Fixed Assets, Net Book Value	65,730,028	72,863,640	7,133,612	10.9%
Cost of Power	96,181,988	102,012,056	5,830,068	6.1%
Operation Expenses	1,167,906	919,397	(248,509)	-21.3%
Maintenance Expenses	1,094,190	1,313,715	219,525	20.1%
Billing and Collecting Expenses	2,398,127	2,462,960	64,833	2.7%
Administrative and General Expenses	6,430,919	6,361,731	(69,187)	-1.1%
Taxes Other than Income Taxes	149,309	152,292	2,983	2.0%
Working Capital	107,422,438	113,222,151	5,799,713	5.4%
Working Capital Allowance	16,113,366	16,983,323	869,957	5.4%
Rate Base	81,843,394	89,846,963	8,003,569	9.8%

The increase in average net fixed assets of $7,133,612 is due to:

- Capital rebuilds (overhead, underground and station assets) required as part of s renewal to maintain or improve system reliability. Of significance is the replacement of the station power transformer at MS13 and related UG lead primary cables, along with the reconstruction of two underground below grade transformer vaults and associated equipment upgrades with modernized intelligent units.
- Phase 1 of the major overhead plant expansion and rebuilds to allow load transfer from Wilson TS to Thornton TS and provide station capacity for ongoing increased load growth north of Oshawa

- IT system security upgrades, including MAS, ODS and GIS enhancements
- Distribution plant expansion to eliminate Long Term Load Transfer (LTLT) customers with HONI
- Capital additions resulting from increased residential and commercial subdivision development
- Year over year actual working capital allowance increased largely from an increase in cost of power ($5,830,068) and, to a lesser extent, lower OM&A expenses ($30,355).
- Billed demand and consumption for 2013 was in line with 2012 (2013 was lower than 2012 by less than 1%). However, cost of power was higher by approximately 6% due to increased rates in the Province.
- OM&A expenses were marginally lower year over year and the variance is less than the materiality threshold.

2014 Bridge Year Forecast Comparison to 2013 Actual Rate Base

The forecast rate base of $98,382,653 for the 2014 Bridge Year increased by $8,535,690 compared to 2013 actual. Average net fixed assets increased by $6,945,786 and working capital allowance of $1,589,904.

The following table provides the variance calculations:

TABLE 2-9 – 2014 BRIDGE YEAR FORECAST COMPARISON TO 2013 ACTUAL RATE BASE

Account Description	Actual 2013	Bridge Year 2014	Variance $	Variance %
Opening Fixed Assets, Net Book Value	69,526,603	76,200,678	6,674,075	9.6%
Closing Fixed Assets, Net Book Value	76,200,678	83,418,175	7,217,497	9.5%
Average Fixed Assets, Net Book Value	72,863,640	79,809,426	6,945,786	9.5%
Cost of Power	102,012,056	112,530,041	10,517,985	10.3%
Operation Expenses	919,397	1,025,060	105,663	11.5%
Maintenance Expenses	1,313,715	1,311,703	(2,012)	-0.2%
Billing and Collecting Expenses	2,462,960	2,594,648	131,688	5.3%
Administrative and General Expenses	6,361,731	6,204,724	(157,008)	-2.5%
Taxes Other than Income Taxes	152,292	155,338	3,046	2.0%
Working Capital	113,222,151	123,821,514	10,599,363	9.4%
Working Capital Allowance	16,983,323	18,573,227	1,589,904	9.4%
Rate Base	89,846,963	98,382,653	8,535,690	9.5%

The 2014 bridge year average net fixed assets increased by $6,945,786 due to:

- Capital rebuilds (overhead, underground and station assets) required as part of asset renewal to maintain or improve system reliability. Of significance is the replacement of the MS14 Switchgear and related UG 13.8kV lead primary feeders; the replacement of station power transformer at MS5; and the reconstruction of an underground below grade transformer vault and associated equipment upgrades with modernized intelligent units.
- Phase 2 of the overhead plant expansion and rebuilds to allow load transfer from Wilson TS to Thornton TS and provide station capacity for ongoing increased load growth north of Oshawa.
- Phase 1 and 2 of the Distribution UG Vault Automation project involving the replacement of old switches with intelligent, remote operated switches to form an underground self-healing system in downtown Oshawa.
- IT system security upgrades, including MAS, ODS and GIS enhancements.

- Distribution plant expansion to eliminate Long Term Load Transfer (LTLT) customers with HONI.

- Capital additions resulting from increased residential and commercial subdivision development.

Year over year actual working capital allowance increased largely from an increase in cost of power ($10,517,985) and, to a lesser extent, higher OM&A expenses ($81,378).

Forecast billed demand and consumption for 2014 is expected to increase by approximately 2% and 1% respectively compared with actual 2013 results. However, year over year cost of power is forecast to be higher by approximately 10%.

OM&A expenses were less than 1% higher year over year and the variance is less than the materiality threshold.

2015 Test Year Forecast to 2014 Bridge Year Forecast Rate Base

The forecast rate base of $104,990,575 for the 2015 Test Year is expected to increase by $6,607,922 compared to forecast for the 2014 Bridge Year. Average net fixed assets increased by $7,919,681 offset by a reduction to working capital allowance of $1,311,760.

The following table provides the variance calculations:

TABLE 2-10 –2015 TEST YEAR FORECAST TO 2014 BRIDGE YEAR FORECAST RATE BASE

Account Description	Bridge Year 2014	Test Year 2015	Variance $	Variance %
Opening Fixed Assets, Net Book Value	76,200,678	83,418,175	7,217,497	9.5%
Closing Fixed Assets, Net Book Value	83,418,175	92,040,040	8,621,866	10.3%
Average Fixed Assets, Net Book Value	79,809,426	87,729,108	7,919,681	9.9%
Cost of Power	112,530,041	120,634,817	8,104,776	7.2%
Operation Expenses	1,025,060	1,288,019	262,959	25.7%
Maintenance Expenses	1,311,703	1,346,279	34,576	2.6%
Billing and Collecting Expenses	2,594,648	2,653,062	58,414	2.3%
Administrative and General Expenses	6,204,724	6,699,898	495,174	8.0%
Taxes Other than Income Taxes	155,338	158,445	3,107	2.0%
Working Capital	123,821,514	132,780,518	8,959,005	7.2%
Working Capital Allowance	18,573,227	17,261,467	(1,311,760)	-7.1%
Rate Base	98,382,653	104,990,575	6,607,922	6.7%

The increase in average net fixed assets by $7,919,681 is primarily due to:

- Third party's request for OPUCN plant relocation, specifically to facilitate the completion of ECGP's highway 407 construction and its scheduled opening in Dec 2015. The Region of Durham has also carried over into 2015, road reconstruction that was planned for or started in 2014 and not completed.
- OPUCN's proposed preliminary capital contribution (1st payment) to HONI for transmission station capacity at Thornton TS. Preliminary estimated total contribution spread over two years (2015 and 2016).
- Design phase of the proposed municipal substation (MS9). Turn-key project, including required distribution primary feeders, scheduled completion over 5 years (2015-2019).
- Phase 3 of the Distribution UG Vault Automation project involving the replacement of old switches with intelligent, remote operated switches to form an underground self-healing system in downtown Oshawa.

- Installation of Outage Management System (OMS); along with IT system upgrades.
- Sustaining capital rebuilds (overhead, underground and station assets) required as part of asset renewal to maintain or improve system reliability.

Year over year forecast working capital is expected to increase by $8,959,005 however, working capital allowance will decrease significantly because the rate applied in the calculation is decreasing from 15% to 13% based upon a Lead/Lag Study prepared for OPUCN which is provided in this application below. The impact of the rate reduction on 2015 working capital allowance is estimated to be $2,655,610.

When comparing the working capital allowance for 2015 with 2014, the impact of the rate reduction to 13% was offset by $1,343,850 related to increases in cost of power totalling $8,104,776 and controllable expenses in the amount of $854,229.

Forecast billed demand and consumption for the 2015 Test Year are 2% and 1% respectively, higher than forecast for the 2014 Bridge Year.

Rates for cost of power are explained in detail below. For the Test Years 2015 through 2019, OPUCN has applied rates for commodity based upon Board's *Regulated Price Plan Price Report - November 1, 2014 to October 31, 2015 (Report)* issued on October 16, 2014.

In addition, current active rates for additional billing determinants including; Smart Meter Entity Charge, Ontario Clean Energy Benefit, Wholesale Market Services, Transmission - Network, Transmission - Connection and Rural Rate Assistance, were used for the Test Years.

OM&A expenses forecast for the 2015 Test Year are approximately 8% higher than 2014 Bridge Year forecast. Labour, professional services and contractor costs are forecast to increase by $870,000 which explains the majority of the year over year change in OM&A expenses. OPUCN's full-time equivalent ("FTE") labour force is expected to increase by 5.5 employees in 2015; 2 additional headcount when comparing the number of employees on December 31st of each year. In addition: professional services in 2014 were lower than historical trends and have been forecast according to the trends for 2015; and contractor costs are expected to increase by approximately 10% in accordance with the increase in related construction work described in OPUCN's DSP.

2016 Through 2019 Test Years Forecast to 2015 Test Year Forecast Rate Base

The forecast rate base for the 2019 final Test Year is $133,201,327 compared with $104,990,575 in the first Test Year, 2015. This represents an increase of $28,201,327, or approximately 27% over the four year period.

Average net fixed assets increase by $27,388,508 and working capital allowance by $822,244.

The following tables provide the rate base and variance calculations:

TABLE 2-11 - 2015 TO 2019 TEST YEARS FORECAST RATE BASE

Account Description	Test Year	Test Years			
	2015	2016	2017	2018	2019
Opening Fixed Assets, Net Book Value	83,418,175	92,040,040	98,554,606	105,743,420	112,613,084
Closing Fixed Assets, Net Book Value	92,040,040	98,554,606	105,743,420	112,613,084	117,622,147
Average Fixed Assets, Net Book Value	87,729,108	95,297,323	102,149,013	109,178,252	115,117,616
Cost of Power	120,634,817	122,428,838	123,586,740	124,964,741	125,921,985
Operation Expenses	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
Maintenance Expenses	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
Billing and Collecting Expenses	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
Administrative and General Expenses	6,699,898	6,877,527	6,942,612	7,079,635	7,219,041
Taxes Other than Income Taxes	158,445	161,613	165,007	168,473	172,010
Working Capital	132,780,518	135,043,042	136,473,428	138,074,546	139,105,474
Working Capital Allowance	17,261,467	17,555,595	17,741,546	17,949,691	18,083,712
Rate Base	104,990,575	112,852,919	119,890,558	127,127,943	133,201,327

TABLE 2-12 - 2015 TO 2019 TEST YEARS FORECAST RATE BASE VARIANCES

Account Description	$ Variance				% Variance			
	2016	2017	2018	2019	2016	2017	2018	2019
Opening Fixed Assets, Net Book Value	8,621,866	6,514,565	7,188,814	6,869,664	10.34%	7.08%	7.29%	6.50%
Closing Fixed Assets, Net Book Value	6,514,565	7,188,814	6,869,664	5,009,063	7.08%	7.29%	6.50%	4.45%
Average Fixed Assets, Net Book Value	7,568,216	6,851,690	7,029,239	5,939,364	8.63%	7.19%	6.88%	5.44%
Cost of Power	1,794,021	1,157,902	1,378,000	957,244	1.49%	0.95%	1.12%	0.77%
Operation Expenses	196,129	109,350	(14,353)	(168,631)	15.23%	7.37%	-0.90%	-10.68%
Maintenance Expenses	29,236	29,954	30,608	31,276	2.17%	2.18%	2.18%	2.18%
Billing and Collecting Expenses	62,339	64,701	66,374	68,096	2.35%	2.38%	2.39%	2.39%
Administrative and General Expenses	177,629	65,085	137,023	139,405	2.65%	0.95%	1.97%	1.97%
Taxes Other than Income Taxes	3,169	3,394	3,465	3,538	2.00%	2.10%	2.10%	2.10%
Working Capital	2,262,523	1,430,387	1,601,118	1,030,928	1.70%	1.06%	1.17%	0.75%
Working Capital Allowance	294,128	185,950	208,145	134,021	1.70%	1.06%	1.17%	0.75%
Rate Base	7,862,344	7,037,640	7,237,385	6,073,384	7.49%	6.24%	6.04%	4.78%

Over the period 2016 – 2019, the increase in net fixed assets compared with 2015 of $27,388,508 is primarily due to:

- OPUCN capital contributions to HONI to address transmission station capacity at both Wilson TS and Thornton TS over the 5 year period. These contributions are preliminary and will most likely increase subject to the final outcomes of the Regional Planning and Local LDCs planning meetings.
- The design and construction and in service of proposed municipal substation MS9, along with required distribution primary feeders.
- Replacement of fleet that has reached its end of life.
- Replacement of servers (production and DR) that will reached its end of life and whose maintenance will no longer be supported by vendor; including replacement of the Operational Data Storage (ODS).

Working capital allowance is forecast to increase at a cumulative average annual rate of 1.2% from 2015 to 2019.

Cost of power is expected to increase by $5,287,168 over the Test Years and OM&A expenses by $1,037,788. The average annual percent increase for cost of power and OM&A expenses is 1.1% and 2.1% respectively.

Forecast billed demand and consumption for the Test Years 2016 through 2019 are estimated to increase by approximately 2.6% and 1.2% respectively, per year on average.

With respect to forecasting rates for cost of power, OPUCN is seeking as part of this Application (Exhibit 1) a mechanism to adjust its working capital allowance annually for the actual change in rates for cost of power. Historically, the change in rates for cost of power have been volatile and in recent years the increases have been substantially greater than inflation. OPUCN has requested the mechanism to avoid speculating cost of power rates and unfairly impacting rates for customers or the financial results of the Company.

The net increase in OM&A expenses forecast for the Test Years 2016 through 2019 is estimated to mirror the rate of inflation forecast for the period which is approximately 2% per year (based upon a weighted average total for labour and non-labour inflation rates found in Exhibit 4). OPUCN's full-time equivalent ("FTE") labour force is expected to be 80.8 in 2019 which is consistent with 2015 estimates totalling 80.4. Throughout the period, FTE's fluctuate to a high of 84.6 due to succession planning however, are expected to normalize by 2019.

It is important to note, OPUCN's OM&A expenses are forecast to increase by only the estimated inflation rate over the period even though the increase in customer growth is forecast to be approximately 15% due mainly to development in and around the extension of the 407 ETR Highway. In order to accomplish this OPUCN will need to continue operating at the industry's top levels of efficiency to avoid expenditures that would otherwise be required to accommodate this level of customer growth.

OPUCN's forecast OM&A costs per customer is expected to remain at $208 in 2019; the amount reported in the Board's *2013 Yearbook of Electricity Distributors*.

To underline OPUCN's ongoing effort to achieve operational efficiencies, the Company has been assigned to Group II of the *Stretch Factor Assignments by Group* reported in Pacific Economics Group Research, LLC's (PEG) *Empirical Research in Support of*

Incentive Rate-Setting: 2013 Benchmarking Update Report to the Ontario Energy Board. Group II is the second most efficient category out of five categories as indicated by the Stretch Factor applied.

In addition, the following table and graph which provide total OM&A expenses per customer for OPUCN and comparable LDCs, including the industry average, highlight OPUCN's relative efficiencies.

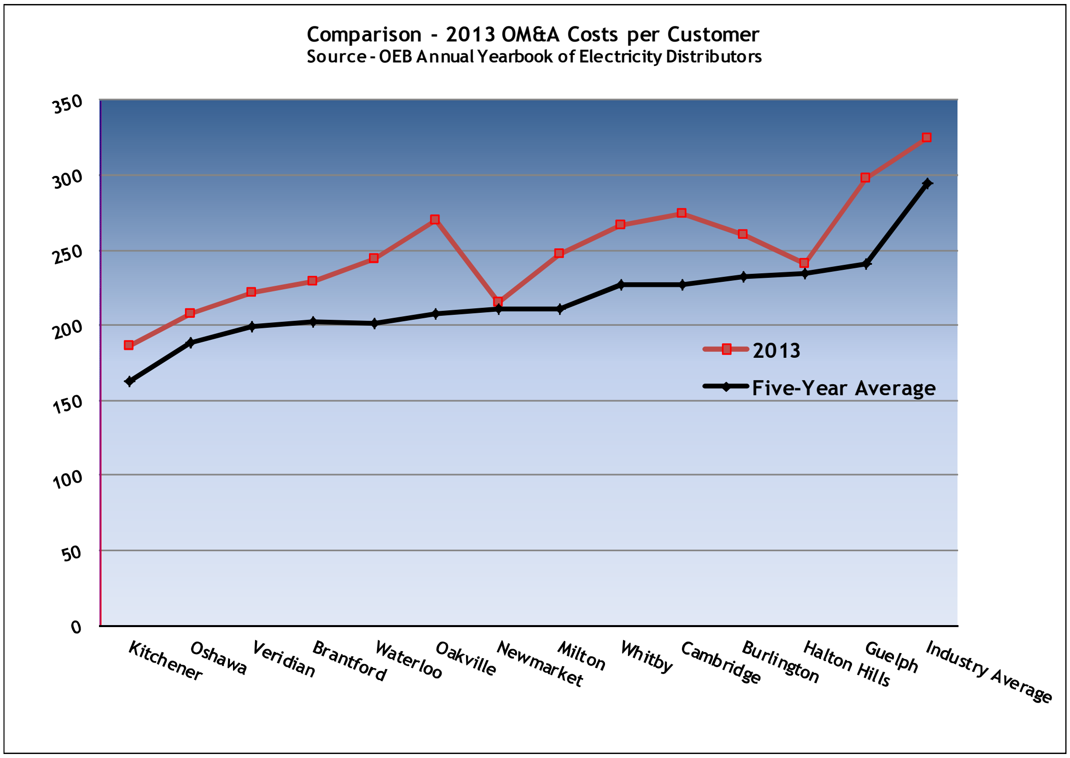
The following table includes OM&A per customer for each of the last five years as reported in the Board's annual Yearbook of Electricity Distributors and the five year average:

TABLE 2-13 - OM&A EXPENSES PER CUSTOMER FOR OPUCN AND COMPARABLE LDCS

Net OM&A Per Customer	Kitchener	Oshawa	Veridian	Brantford	Waterloo	Oakville	Newmarket
2009	142	168	174	205	172	163	199
2010	142	168	183	201	191	176	203
2011	155	191	181	176	182	206	198
2012	189	211	238	199	220	223	240
2013	186	208	221	230	244	270	215
Average	163	189	199	202	202	208	211

Net OM&A Per Customer	Milton	Whitby	Cambridge	Burlington	Halton Hills	Guelph	Industry Average
2009	195	214	197	208	209	194	267
2010	192	223	188	218	211	195	282
2011	210	214	209	225	227	251	292
2012	209	219	266	252	283	267	309
2013	248	266	275	260	241	298	325
Average	211	227	227	233	234	241	295

The following graph depicts results for 2013 and the five year average for each of the comparable LDCs and the industry average.



CONTINUITY STATEMENT AND RECONCILIATION

OPUCN has provided its continuity statements in the following Appendix 2-1. The opening and closing balances of gross assets and accumulated depreciation that have been used to calculate the fixed asset component of rate base, correspond to the respective balances before Work in Progress ('WIP') in the fixed asset continuity statements.

Additions of Smart Meters in 2011 were included in the 2012 opening balance of rate base.

OPUCN made the transition from CGAAP to MIFRS in its 2012 cost of service application. The following continuity statements are reported under MIFRS as per the Board's IFRS Guidance.

The following continuity statements have been provided:

- 2012 Board-Approved

- 2012 Actual
- 2013 Actual
- Forecast for the 2014 Bridge Year
- Forecast for the 2015 – 2019 Test Years

APPENDIX 2-1 CONTINUITY STATEMENTS

Fixed Asset Continuity Schedule (Distribution & Operations)
2012 Board Approved : As at December 31, 2012

			Cost			Accumulated Depreciation			
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Closing Balance**	**Opening Balance**	**Additions**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	293,875	0	293,875	0	0	0	293,875
CEC	1806	Land Rights	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	272,147	0	272,147	6,686	6,686	13,372	258,775
13	1810	Leasehold Improvements	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment - Normally Prima	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Prima	7,937,456	5,574,429	13,511,885	196,443	297,366	493,809	13,018,077
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	10,700,173	1,397,133	12,097,305	263,382	293,350	556,732	11,540,573
47	1835	Overhead Conductors and Devices	6,715,089	478,013	7,193,102	153,177	143,335	296,512	6,896,591
47	1840	Underground Conduit	0	0	0	0	0	0	0
47	1845	Underground Conductors and Devices	25,931,790	3,032,372	28,964,162	850,027	926,641	1,776,668	27,187,494
47	1850	Line Transformers	2,577,958	146,865	2,724,823	86,319	90,277	176,597	2,548,226
47	1855	Services	0	0	0	0	0	0	0
47	1860	Meters	7,373,588	383,974	7,757,562	675,791	569,623	1,245,414	6,512,148
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0
N/A	1905	Land	0	0	0	0	0	0	0
CEC	1906	Land Rights	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	408,244	25,000	433,244	73,715	102,215	175,931	257,314
8	1915	Office Furniture and Equipment	53,686	0	53,686	19,934	12,665	32,600	21,086
10	1920	Computer Equipment - Hardware	230,573	50,000	280,573	74,984	61,826	136,810	143,763
12	1925	Computer Software	459,420	50,000	509,420	161,544	145,627	307,170	202,250
10	1930	Transportation Equipment	1,567,750	1,220,000	2,787,750	134,825	246,408	381,233	2,406,517
8	1935	Stores Equipment	13,285	0	13,285	2,406	2,406	4,812	8,473
8	1940	Tools, Shop and Garage Equipment	929,656	50,000	979,656	378,646	199,393	578,039	401,617
8	1945	Measurement and Testing Equipment	155,475	0	155,475	59,000	22,797	81,798	73,677
8	1950	Power Operated Equipment	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	0	0	0	0	0	0	0
47	1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0
47	1975	Load Management Controls - Utility Premises	404,302	450,000	854,302	20,145	34,083	54,228	800,074
47	1980	System Supervisory Equipment	0	0	0	0	0	0	0
47	1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0
47	1995	Contributions and Grants	(1,994,208)	(2,641,312)	(4,635,520)	(23,348)	(78,515)	(101,863)	(4,533,657)
	2005	Property under Capital Lease	0	0	0	0		0	0
		Total before Work in Process	**64,030,259**	**10,216,474**	**74,246,733**	**3,133,675**	**3,076,184**	**6,209,859**	**68,036,873**
WIP		Work in Process	1,088,128	0	1,088,128	0		0	1,088,128
		Total after Work in Process	**65,118,387**	**10,216,474**	**75,334,861**	**3,133,675**	**3,076,184**	**6,209,859**	**69,125,002**

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2012**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	715,690	459,115	0	1,174,804	(365,879)	(206,525)	0	(572,404)	602,400
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	709,412	0	0	709,412	(359,638)	(14,236)	0	(373,874)	335,538
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	15,650,967	4,461,905	(940,990)	19,171,881	(7,935,939)	(304,486)	716,211	(7,524,214)	11,647,668
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	29,012,569	1,593,281	0	30,605,850	(13,619,315)	(404,082)	0	(14,023,397)	16,582,453
47	1835	Overhead Conductors & Devices	17,881,699	806,545	0	18,688,244	(9,097,722)	(210,507)	0	(9,308,228)	9,380,015
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	38,060,389	878,003	0	38,938,391	(16,483,653)	(674,673)	0	(17,158,325)	21,780,066
47	1850	Line Transformers	48,776,843	1,865,329	(208,100)	50,434,073	(28,798,432)	(665,651)	208,100	(29,255,984)	21,178,089
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	2,647,580	0	(3,090)	2,644,490	(2,483,293)	(712,727)	1,434	(3,194,586)	(550,097)
47	1860	Meters (Smart Meters)	6,971,136	247,975	0	7,219,111	0	0	0	0	7,219,111
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	689,468	200,046	0	889,513	(205,854)	(170,615)	0	(376,469)	513,044
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	684,896	6,911	0	691,808	(643,906)	(8,754)	0	(652,660)	39,148
10	1920	Computer Equipment - Hardware	2,167,954	0	0	2,167,954	(2,064,017)	0	0	(2,064,017)	103,937
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	0	129,776	0	129,776	(57,524)	(17,430)	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	3,072,834	1,405,317	(143,213)	4,334,938	(2,140,152)	(171,211)	143,213	(2,168,150)	2,166,788
8	1935	Stores Equipment	24,516	0	0	24,516	(24,228)	(288)	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,176,145	84,728	0	2,260,872	(1,489,162)	(217,059)	0	(1,706,220)	554,652
8	1945	Measurement & Testing Equipment	424,560	14,905	0	439,465	(268,607)	(13,475)	0	(282,082)	157,383
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	266,585	147,267	0	413,853	(251,398)	(12,724)	0	(264,123)	149,730
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	95,567	62,078	0	157,645	(59,758)	(19,353)	0	(79,111)	78,534
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(742,337)	(17,494)	0	(759,831)	261,862
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(29,357,707)	(1,271,166)	0	(30,628,873)	6,966,724	568,862	0	7,535,586	(23,093,287)
	etc.					0				0	0
						0				0	0
		Sub-Total	**142,387,289**	**11,092,013**	**(1,295,393)**	**152,183,909**	**(80,453,836)**	**(3,272,427)**	**1,068,958**	**(82,657,305)**	**69,526,604**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**142,387,289**	**11,092,013**	**(1,295,393)**	**152,183,909**	**(80,453,836)**	**(3,272,427)**	**1,068,958**	**(82,657,305)**	**69,526,604**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(3,272,427)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(3,272,427)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2013

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	1,174,804	377,372	0	1,552,176	(572,404)	(366,622)	0	(939,026)	613,150
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	709,412	0	0	709,412	(373,874)	(14,197)	0	(388,071)	321,341
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	19,171,881	3,998	(200,000)	18,975,879	(7,524,214)	(322,548)	186,015	(7,660,747)	11,315,132
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	30,605,850	4,590,574	(750,000)	34,446,424	(14,023,397)	(481,215)	697,555	(13,807,057)	20,639,366
47	1835	Overhead Conductors & Devices	18,688,244	1,587,521	(956,064)	19,319,701	(9,308,228)	(268,031)	889,209	(8,687,050)	10,632,650
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	38,938,391	2,500,792	(350,000)	41,089,183	(17,158,325)	(803,428)	325,525	(17,636,228)	23,452,956
47	1850	Line Transformers	50,434,073	2,370,264	(800,000)	52,004,337	(29,255,984)	(738,775)	744,058	(29,250,700)	22,753,636
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	2,644,490	57,203	0	2,701,692	(3,194,586)	0	0	(3,194,586)	(492,894)
47	1860	Meters (Smart Meters)	7,219,111	514,823	0	7,733,934	0	(747,565)	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	889,513	18,265	0	907,778	(376,469)	(153,806)	0	(530,275)	377,503
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	691,808	31,131	0	722,939	(652,660)	(9,661)	0	(662,321)	60,618
10	1920	Computer Equipment - Hardware	2,167,954	241,584	0	2,409,538	(2,064,017)	(86,794)	0	(2,150,811)	258,727
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	4,334,938	17,542	(249,145)	4,103,335	(2,168,150)	(274,279)	244,700	(2,197,729)	1,905,606
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,260,872	112,253	0	2,373,125	(1,706,220)	(200,143)	0	(1,906,363)	466,762
8	1945	Measurement & Testing Equipment	439,465	19,169	0	458,634	(282,082)	(14,792)	0	(296,874)	161,760
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	413,853	4,280	0	418,133	(264,123)	(20,482)	0	(284,605)	133,528
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(79,111)	(19,187)	0	(98,298)	59,347
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(759,831)	(17,447)	0	(777,278)	244,415
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(30,628,873)	(1,699,267)	0	(32,328,140)	7,535,586	687,172	(3,484)	8,219,274	(24,108,866)
	etc.					0				0	0
						0				0	0
		Sub-Total	**152,183,909**	**10,747,504**	**(3,305,209)**	**159,626,204**	**(82,657,305)**	**(3,851,800)**	**3,083,578**	**(83,425,527)**	**76,200,677**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**152,183,909**	**10,747,504**	**(3,305,209)**	**159,626,204**	**(82,657,305)**	**(3,851,800)**	**3,083,578**	**(83,425,527)**	**76,200,677**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(3,851,800)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	(3,851,800)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	1,552,176	354,000	0	1,906,176	(939,026)	(406,214)	0	(1,345,240)	560,937
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	709,412	0	0	709,412	(388,071)	(14,197)	0	(402,268)	307,145
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	18,975,879	1,083,303	(378,835)	19,680,347	(7,660,747)	(390,557)	284,586	(7,766,718)	11,913,629
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	34,446,424	3,589,139	(1,430,580)	36,604,983	(13,807,057)	(554,572)	1,334,584	(13,027,045)	23,577,937
47	1835	Overhead Conductors & Devices	19,319,701	2,651,741	(771,673)	21,199,769	(8,687,050)	(252,090)	711,031	(8,228,109)	12,971,659
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	41,089,183	4,266,560	(742,650)	44,613,093	(17,636,228)	(817,879)	702,992	(17,751,114)	26,861,979
47	1850	Line Transformers	52,004,337	531,671	(173,885)	52,362,123	(29,250,700)	(774,738)	163,293	(29,862,145)	22,499,978
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	2,701,692	275,616	(1,192)	2,976,116	(3,194,586)	(776,351)	1,061	(3,969,877)	(993,761)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	907,778	180,000	0	1,087,778	(530,275)	(133,851)	0	(664,126)	423,652
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	722,939	20,000	0	742,939	(662,321)	(7,441)	0	(669,761)	73,177
10	1920	Computer Equipment - Hardware	2,409,538	186,000	0	2,595,538	(2,150,811)	(128,947)	0	(2,279,758)	315,780
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	4,103,335	52,906	0	4,156,241	(2,197,729)	(274,109)	0	(2,471,838)	1,684,403
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,373,125	166,193	(16,134)	2,523,184	(1,906,363)	(176,452)	14,535	(2,068,281)	454,903
8	1945	Measurement & Testing Equipment	458,634	7,037	(577)	465,093	(296,874)	(16,817)	570	(313,121)	151,973
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,133	0	0	418,133	(284,605)	(15,854)	0	(300,459)	117,674
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(98,298)	(12,757)	0	(111,054)	46,591
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(777,278)	(17,447)	0	(794,725)	226,969
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(32,328,140)	(1,635,000)	0	(33,963,140)	8,219,274	706,399	0	8,780,753	(25,182,387)
	etc.					0				0	0
						0				0	0
		Sub-Total	**159,626,204**	**11,729,165**	**(3,515,526)**	**167,839,843**	**(83,425,527)**	**(4,063,873)**	**3,212,652**	**(84,421,669)**	**83,418,174**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**159,626,204**	**11,729,165**	**(3,515,526)**	**167,839,843**	**(83,425,527)**	**(4,063,873)**	**3,212,652**	**(84,421,669)**	**83,418,174**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(4,063,873)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(4,063,873)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2015

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	1,906,176	739,565	(975)	2,644,767	(1,345,240)	(433,162)	487	(1,777,915)	866,852
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	709,412	750,000	0	1,459,412	(402,268)	(20,245)	0	(422,513)	1,036,899
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	19,680,347	1,820,436	(79,665)	21,421,119	(7,766,718)	(455,298)	79,004	(8,143,012)	13,278,107
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	36,604,983	6,241,860	(1,278,749)	41,568,094	(13,027,045)	(609,644)	1,126,765	(12,509,924)	29,058,170
47	1835	Overhead Conductors & Devices	21,199,769	2,946,495	(623,026)	23,523,238	(8,228,109)	(352,536)	542,535	(8,038,111)	15,485,128
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	44,613,093	3,518,861	(667,534)	47,464,420	(17,751,114)	(824,580)	576,961	(17,998,733)	29,465,687
47	1850	Line Transformers	52,362,123	675,031	(165,725)	52,871,429	(29,862,145)	(784,527)	142,981	(30,503,692)	22,367,738
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	2,976,116	612,932	(94,126)	3,494,923	(3,969,877)	(805,129)	47,519	(4,727,487)	(1,232,564)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,087,778	247,500	0	1,335,278	(664,126)	(171,269)	0	(835,396)	499,883
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	742,939	27,500	0	770,439	(669,761)	(9,434)	0	(679,195)	91,243
10	1920	Computer Equipment - Hardware	2,595,538	266,511	(1,334)	2,860,715	(2,279,758)	(180,849)	667	(2,459,941)	400,775
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	4,156,241	420,000	0	4,576,241	(2,471,838)	(293,863)	0	(2,765,701)	1,810,540
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,523,184	145,324	(14,392)	2,654,116	(2,068,281)	(147,464)	12,188	(2,203,556)	450,559
8	1945	Measurement & Testing Equipment	465,093	8,884	(337)	473,641	(313,121)	(18,346)	307	(331,160)	142,481
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,133	0	0	418,133	(300,459)	(15,854)	0	(316,313)	101,819
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(111,054)	(12,757)	0	(123,811)	33,834
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(794,725)	(58,017)	0	(852,742)	168,951
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(33,963,140)	(4,911,000)	0	(38,874,140)	8,780,753	701,387	0	9,482,141	(29,391,999)
	etc.					0				0	0
						0				0	0
		Sub-Total	**167,839,843**	**13,509,900**	**(2,925,861)**	**178,423,882**	**(84,421,669)**	**(4,491,588)**	**2,529,414**	**(86,383,843)**	**92,040,040**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**167,839,843**	**13,509,900**	**(2,925,861)**	**178,423,882**	**(84,421,669)**	**(4,491,588)**	**2,529,414**	**(86,383,843)**	**92,040,040**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(4,491,588)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(4,491,588)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2016**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	2,644,767	445,026	0	3,089,793	(1,777,915)	(502,319)	0	(2,280,234)	809,559
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	1,459,412	1,000,000	0	2,459,412	(422,513)	(32,094)	0	(454,607)	2,004,805
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	21,421,119	2,209,912	(184,741)	23,446,291	(8,143,012)	(503,368)	184,081	(8,462,300)	14,983,991
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	41,568,094	3,033,573	(834,719)	43,766,948	(12,509,924)	(664,493)	743,138	(12,431,279)	31,335,669
47	1835	Overhead Conductors & Devices	23,523,238	1,584,613	(420,166)	24,687,685	(8,038,111)	(383,286)	375,103	(8,046,294)	16,641,391
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	47,464,420	2,852,223	(539,061)	49,777,582	(17,998,733)	(883,051)	474,724	(18,407,060)	31,370,522
47	1850	Line Transformers	52,871,429	448,362	(131,538)	53,188,254	(30,503,692)	(793,616)	116,760	(31,180,547)	22,007,707
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	3,494,923	615,911	(93,305)	4,017,529	(4,727,487)	(849,076)	47,071	(5,529,492)	(1,511,963)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,335,278	90,000	0	1,425,278	(835,396)	(171,591)	0	(1,006,986)	418,292
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	770,439	10,000	0	780,439	(679,195)	(11,069)	0	(690,264)	90,175
10	1920	Computer Equipment - Hardware	2,860,715	172,405	0	3,033,120	(2,459,941)	(211,296)	0	(2,671,237)	361,883
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	4,576,241	415,000	0	4,991,241	(2,765,701)	(324,118)	0	(3,089,819)	1,901,422
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,654,116	145,820	(15,364)	2,784,573	(2,203,556)	(121,070)	12,968	(2,311,658)	472,915
8	1945	Measurement & Testing Equipment	473,641	59,154	(483)	532,312	(331,160)	(21,581)	435	(352,307)	180,006
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,133	0	0	418,133	(316,313)	(15,854)	0	(332,168)	85,965
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(123,811)	(11,074)	0	(134,885)	22,760
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(852,742)	(46,497)	0	(899,239)	122,454
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(38,874,140)	(1,455,000)	0	(40,329,140)	9,482,141	698,115	0	10,180,256	(30,148,884)
	etc.					0				0	0
						0				0	0
		Sub-Total	**178,423,882**	**11,627,000**	**(2,219,376)**	**187,831,507**	**(86,383,843)**	**(4,847,338)**	**1,954,279**	**(89,276,902)**	**98,554,605**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**178,423,882**	**11,627,000**	**(2,219,376)**	**187,831,507**	**(86,383,843)**	**(4,847,338)**	**1,954,279**	**(89,276,902)**	**98,554,605**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(4,847,338)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(4,847,338)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year **2017**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	3,089,793	135,847	(812)	3,224,828	(2,280,234)	(476,505)	406	(2,756,333)	468,495
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	2,459,412	0	0	2,459,412	(454,607)	(40,158)	0	(494,766)	1,964,647
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	23,446,291	3,752,553	(131,250)	27,067,594	(8,462,300)	(576,258)	130,216	(8,908,342)	18,159,252
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	43,766,948	2,806,491	(382,025)	46,191,413	(12,431,279)	(715,642)	332,721	(12,814,200)	33,377,213
47	1835	Overhead Conductors & Devices	24,687,685	1,834,323	(206,910)	26,315,098	(8,046,294)	(415,322)	183,473	(8,278,143)	18,036,955
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	49,777,582	2,913,604	(552,227)	52,138,960	(18,407,060)	(933,285)	493,151	(18,847,195)	33,291,765
47	1850	Line Transformers	53,188,254	453,753	(83,357)	53,558,650	(31,180,547)	(801,198)	74,376	(31,907,369)	21,651,281
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	4,017,529	748,885	(77,772)	4,688,642	(5,529,492)	(898,798)	39,092	(6,389,198)	(1,700,556)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,425,278	45,000	0	1,470,278	(1,006,986)	(127,163)	0	(1,134,149)	336,129
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	780,439	5,000	0	785,439	(690,264)	(11,387)	0	(701,651)	83,788
10	1920	Computer Equipment - Hardware	3,033,120	98,267	(1,112)	3,130,275	(2,671,237)	(198,711)	556	(2,869,392)	260,884
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	4,991,241	440,000	0	5,431,241	(3,089,819)	(335,065)	0	(3,424,884)	2,006,357
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,784,573	144,327	(9,163)	2,919,736	(2,311,658)	(117,558)	8,446	(2,420,769)	498,967
8	1945	Measurement & Testing Equipment	532,312	68,948	(481)	600,780	(352,307)	(23,646)	458	(375,494)	225,286
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,133	0	0	418,133	(332,168)	(15,854)	0	(348,022)	70,110
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(134,885)	(6,299)	0	(141,185)	16,460
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(899,239)	(790)	0	(900,030)	121,664
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(40,329,140)	(1,075,000)	0	(41,404,140)	10,180,256	692,669	0	10,872,924	(30,531,216)
	etc.					0				0	0
						0				0	0
		Sub-Total	**187,831,507**	**12,372,000**	**(1,445,109)**	**198,758,398**	**(89,276,902)**	**(5,000,972)**	**1,262,895**	**(93,014,979)**	**105,743,419**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**187,831,507**	**12,372,000**	**(1,445,109)**	**198,758,398**	**(89,276,902)**	**(5,000,972)**	**1,262,895**	**(93,014,979)**	**105,743,419**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(5,000,972)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(5,000,972)

Fixed Asset Continuity Schedule - MIFRS

Year 2018

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	3,224,828	242,233	(812)	3,466,249	(2,756,333)	(357,257)	406	(3,113,184)	353,065
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	2,459,412	0	0	2,459,412	(494,766)	(40,158)	0	(534,924)	1,924,488
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	27,067,594	1,509,126	(130,844)	28,445,877	(8,908,342)	(640,394)	130,183	(9,418,553)	19,027,324
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	46,191,413	3,066,233	(760,111)	48,497,535	(12,814,200)	(765,551)	608,887	(12,970,864)	35,526,671
47	1835	Overhead Conductors & Devices	26,315,098	2,117,978	(405,108)	28,027,968	(8,278,143)	(452,569)	325,010	(8,405,701)	19,622,266
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	52,138,960	4,719,972	(586,808)	56,272,123	(18,847,195)	(1,008,014)	483,921	(19,371,287)	36,900,836
47	1850	Line Transformers	53,558,650	494,501	(135,985)	53,917,166	(31,907,369)	(808,842)	110,457	(32,605,753)	21,311,412
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	4,688,642	602,951	(78,445)	5,213,148	(6,389,198)	(949,960)	39,587	(7,299,571)	(2,086,423)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,470,278	45,000	0	1,515,278	(1,134,149)	(118,827)	0	(1,252,976)	262,303
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	785,439	5,000	0	790,439	(701,651)	(11,848)	0	(713,500)	76,939
10	1920	Computer Equipment - Hardware	3,130,275	261,160	(1,112)	3,390,324	(2,869,392)	(190,191)	556	(3,059,026)	331,297
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,431,241	190,000	0	5,621,241	(3,424,884)	(366,143)	0	(3,791,028)	1,830,213
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	2,919,736	152,123	(15,055)	3,056,805	(2,420,769)	(119,736)	12,119	(2,528,387)	528,418
8	1945	Measurement & Testing Equipment	600,780	132,774	(590)	732,964	(375,494)	(38,436)	478	(413,452)	319,512
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	418,133	31,950	0	450,083	(348,022)	(17,452)	0	(365,474)	84,609
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(141,185)	(6,286)	0	(147,471)	10,174
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(900,030)	0	0	(900,030)	121,664
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(41,404,140)	(1,095,000)	0	(42,499,140)	10,872,924	688,593	0	11,561,518	(30,937,622)
	etc.					0				0	0
						0				0	0
		Sub-Total	**198,758,398**	**12,476,000**	**(2,114,869)**	**209,119,529**	**(93,014,979)**	**(5,203,071)**	**1,711,604**	**(96,506,445)**	**112,613,083**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**198,758,398**	**12,476,000**	**(2,114,869)**	**209,119,529**	**(93,014,979)**	**(5,203,071)**	**1,711,604**	**(96,506,445)**	**112,613,083**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(5,203,071)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(5,203,071)

Appendix 2-BA
Fixed Asset Continuity Schedule - MIFRS

Year 2019

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	3,466,249	194,233	(812)	3,659,670	(3,113,184)	(232,570)	406	(3,345,348)	314,322
CEC	1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	0	0
N/A	1805	Land	293,875	0	0	293,875	0	0	0	0	293,875
47	1808	Buildings	2,459,412	0	0	2,459,412	(534,924)	(40,158)	0	(575,082)	1,884,330
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment <50 kV	28,445,877	2,506,205	(299,094)	30,652,988	(9,418,553)	(686,847)	265,673	(9,839,727)	20,813,261
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	48,497,535	2,846,359	(604,238)	50,739,656	(12,970,864)	(817,672)	471,046	(13,317,491)	37,422,166
47	1835	Overhead Conductors & Devices	28,027,968	1,814,355	(323,126)	29,519,197	(8,405,701)	(490,445)	254,678	(8,641,469)	20,877,728
47	1840	Underground Conduit	0	0	0	0	0	0	0	0	0
47	1845	Underground Conductors & Devices	56,272,123	2,803,734	(533,250)	58,542,608	(19,371,287)	(1,081,624)	450,645	(20,002,267)	38,540,341
47	1850	Line Transformers	53,917,166	464,855	(113,758)	54,268,263	(32,605,753)	(816,309)	92,271	(33,329,791)	20,938,472
47	1855	Services (Overhead & Underground)	0	0	0	0	0	0	0	0	0
47	1860	Meters	5,213,148	602,560	(78,166)	5,737,541	(7,299,571)	(985,260)	39,338	(8,245,492)	(2,507,951)
47	1860	Meters (Smart Meters)	7,733,934	0	0	7,733,934	(747,565)	0	0	(747,565)	6,986,369
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	1,515,278	45,000	0	1,560,278	(1,252,976)	(126,000)	0	(1,378,976)	181,303
8	1915	Office Furniture & Equipment (10 years)	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (5 years)	790,439	5,000	0	795,439	(713,500)	(12,214)	0	(725,713)	69,725
10	1920	Computer Equipment - Hardware	3,390,324	99,160	(1,112)	3,488,372	(3,059,026)	(178,667)	556	(3,237,138)	251,235
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	129,776	0	0	129,776	(74,955)	0	0	(74,955)	54,821
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	5,621,241	170,000	0	5,791,241	(3,791,028)	(384,165)	0	(4,175,193)	1,616,049
8	1935	Stores Equipment	24,516	0	0	24,516	(24,516)	0	0	(24,516)	0
8	1940	Tools, Shop & Garage Equipment	3,056,805	150,004	(12,555)	3,194,254	(2,528,387)	(115,985)	10,325	(2,634,047)	560,207
8	1945	Measurement & Testing Equipment	732,964	132,584	(539)	865,009	(413,452)	(57,291)	472	(470,271)	394,738
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	450,083	31,950	0	482,033	(365,474)	(20,647)	0	(386,121)	95,912
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	157,645	0	0	157,645	(147,471)	(6,286)	0	(153,758)	3,888
47	1970	Load Management Controls Customer Premises	107,035	0	0	107,035	(36,163)	0	0	(36,163)	70,871
47	1975	Load Management Controls Utility Premises	1,021,693	0	0	1,021,693	(900,030)	0	0	(900,030)	121,664
47	1980	System Supervisor Equipment	293,582	0	0	293,582	(293,583)	0	0	(293,583)	(1)
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	(42,499,140)	(1,105,000)	0	(43,604,140)	11,561,518	681,444	0	12,242,962	(31,361,178)
	etc.					0				0	0
						0				0	0
		Sub-Total	**209,119,529**	**10,761,000**	**(1,966,649)**	**217,913,879**	**(96,506,445)**	**(5,370,697)**	**1,585,409**	**(100,291,733)**	**117,622,147**
		Less Socialized Renewable Energy Generation Investments (input as negative)				0				0	0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				0				0	0
		Total PP&E	**209,119,529**	**10,761,000**	**(1,966,649)**	**217,913,879**	**(96,506,445)**	**(5,370,697)**	**1,585,409**	**(100,291,733)**	**117,622,147**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)									
		Total						**(5,370,697)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	(5,370,697)

COST OF POWER

Overview

OPUCN has calculated cost of power (COP) for the 2014 Bridge Year and 2015 through 2019 Test Years in support of its rate base calculation, using the load forecast, which is discussed in detail in Exhibit 3 – Operating Revenue.

OPUCN's wholesale market participant (WMP) customers have been excluded from the calculation of electricity and global adjustment costs, as they transact directly with the Independent Electricity System Operator (IESO) for the purchase of electricity. WMP customers are included in the calculation of the retail transmission costs.

For 2014 to 2019, energy revenue is assumed to equal the COP, with no impact to net income, notwithstanding known timing variances associated with the Smart Meter Entity (SME) Charge.

The Filing Requirements state that "The commodity price estimate used to calculate the Cost of Power must be determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP time-of-use (TOU) pricing. The calculation must also reflect the most recent Uniform Transmission Rates approved by the Board…"

For the Test Years 2015 through 2019, OPUCN has applied rates for commodity based upon the Board's *Regulated Price Plan Price Report - November 1, 2014 to October 31, 2015 (Report)* issued on October 16, 2014.

The following table was prepared from information found on Pages 3 and 12 of the *Report*:

TABLE 2-14 – RPP AND NON-RPP RATES (REGULATED PRICE PLAN REPORT)

	Months	16-Oct-14
Nov 14 - Jan 15	1	$ 25.48
Feb 15 - Apr 15	3	$ 20.59
May 15 - Jul 15	3	$ 19.51
Aug 15 - Oct 15	3	$ 16.96
Nov 15 - Jan 16	2	$ 26.69
Weighted Average		$ 20.84
Global Adjustment		$ 74.88
Non-RPP Price		$ 95.72

	Months	16-Oct-14
Load Weighted Price for RPP Consumers		$ 22.52
Forecast Wholesale Electricity Price		$ 20.64
Ratio		$ 1.09
Weighted Average		$ 20.84
Load Weighted Price for RPP Consumers		$ 22.73
Global Adjustment		$ 74.88
Adjustment to Address Bias		$ 1.00
Adjustment to Clear Existing Variance		-$ 3.45
RPP Price		$ 95.16

Commodity rate used for RPP customers for the Test Years, from the table above, is $.09516 per kWh. Rates used for Non-RPP customers are $.02084 and $.07488 per kWh for Commodity and Global Adjustment respectively.

In addition, current active rates for additional billing determinants including; Smart Meter Entity Charge, Ontario Clean Energy Benefit, Wholesale Market Services, Transmission - Network, Transmission - Connection and Rural Rate Assistance, were used for the Test Years.

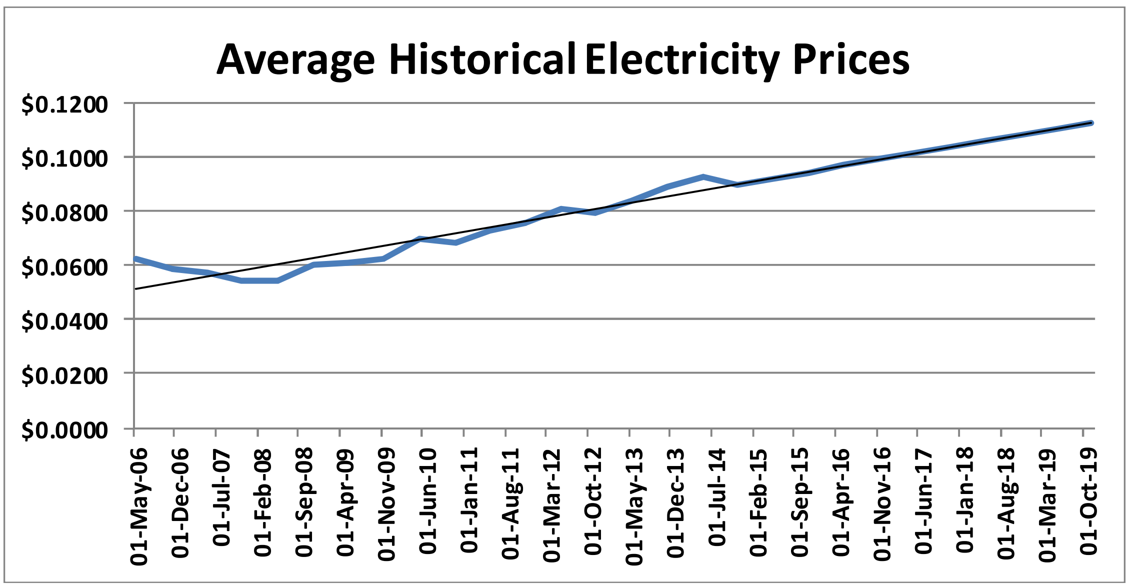
The rates are as follows for additional billing determinants:

Customer Category	Network Service Charge	Line and Connection Charge	Wholesale Market Service Charge	Rural Rate Protection Charge	Smart Meter Entity Charge	Ontario Clean Ontario Benefit
Residential	$ 0.00660	$ 0.00560	$ 0.00520	$ 0.00130	$ 0.78800	10%
General Service < 50 kW	$ 0.00600	$ 0.00510	$ 0.00520	$ 0.00130	$ 0.78800	10%
General Service 50 to 999 kW	$ 2.49290	$ 2.08530	$ 0.00520	$ 0.00130	$ -	10%
General Service 1,000 to 4,999 kW	$ 2.80070	$ 2.33360	$ 0.00520	$ 0.00130	$ -	0%
Large User >5000 kw	$ 2.98410	$ 2.54630	$ 0.00520	$ 0.00130	$ -	0%
Street Lighting	$ 1.48160	$ 2.12000	$ 0.00520	$ 0.00130	$ -	0%
Unmetered Scattered Load	$ 0.00600	$ 0.00510	$ 0.00520	$ 0.00130	$ -	0%
Sentinel Lighting	$ 1.50720	$ 2.15660	$ 0.00520	$ 0.00130	$ -	0%

As noted above, with respect to forecasting rates for COP, OPUCN is seeking as part of this Application (Exhibit 1– Administrative Documents) a mechanism to adjust its working capital allowance annually for the actual change in rates for COP. Historically, the change in rates for COP have been volatile and in recent years the increases have been substantially greater than inflation.

The following chart is provided to support OPUCN's assertion that rates have been volatile and the request to have its working capital allowance adjusted annually to reflect the change in COP rates.

Plotting the linear trend from historical data available from 2006, provides the following results:



The COP for the: 2012 Board-Approved amounts; 2012 and 2013 Actual results; 2014 Bridge Year estimates; and 2015 through 2019 Test Years forecast are summarized in following table. Detailed calculations are provided in Tables 2-15 through 2-21 below.

TABLE 2-15 – COST OF POWER SUMMARY 2012-2019

Year	Commodity	Global Adjustment	Network Service Charge	Line and Connection Charge	Wholesale Market Service Charge	Rural Rate Protection Charge	Smart Meter Entity Charge	Ontario Clean Ontario Benefit	Total
2012 Board-Approved	45,614,419	30,922,213	7,275,370	6,166,389	6,037,115	1,509,279	0	0	97,524,785
2012 Actual	58,754,296	19,539,865	5,989,027	6,148,167	4,424,561	1,326,071	0	0	96,181,988
2013 Actual	62,384,862	20,878,746	6,591,755	6,071,129	4,520,620	1,240,243	324,701	0	102,012,056
2014 Bridge Year	63,763,054	38,437,494	7,178,759	6,081,932	5,961,010	1,452,041	511,577	(10,855,827)	112,530,041
2015 Test Year	64,220,875	46,647,705	7,277,593	6,159,937	6,039,329	1,509,832	526,925	(11,747,379)	120,634,817
2016 Test Year	64,967,705	47,625,239	7,394,616	6,253,104	6,133,157	1,533,289	542,733	(12,021,006)	122,428,838
2017 Test Year	65,235,146	48,474,148	7,465,138	6,312,682	6,193,813	1,548,453	559,014	(12,201,654)	123,586,740
2018 Test Year	65,614,507	49,496,626	7,553,835	6,387,514	6,269,998	1,567,500	479,821	(12,405,060)	124,964,741
2019 Test Year	65,943,303	50,548,253	7,640,771	6,460,816	6,345,001	1,586,250	0	(12,602,409)	125,921,985

The COP calculations and summary by charge type for the 2014 Bridge Year are provided in the following Tables. The COP calculations and summaries by charge type for the 2015 through 2019 Test Years are provided in the following Tables 2-16 through 2-21 respectively.

TABLE 2-16 - 2014 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	481,054,885	0	83.000%
General Service < 50 kW	134,663,866	0	81.7%
General Service 50 to 999 kW	349,725,891	885,168	0.0%
General Service 1,000 to 4,999 kW	72,223,027	159,223	0.0%
Large User >5000 kw	43,637,356	99,132	0.0%
Street Lighting	9,157,883	24,692	0.0%
Unmetered Scattered Load	2,720,085	0	0.0%
Sentinel Lighting	34,756	102	0.0%
TOTAL	1,093,217,749	1,168,317	

Electricity - Commodity RPP	2014	2014 Loss Factor	2014		
Class per Load Forecast RPP	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	399,275,555	1.049	418,680,347	$ 0.08900	$ 37,262,551
General Service < 50 kW	110,020,379	1.049	115,367,369	$ 0.08900	$ 10,267,696
General Service 50 to 999 kW	0	1.049	0	$ 0.08900	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.08900	$ -
Large User >5000 kw	0	1.049	0	$ 0.08900	$ -
Street Lighting	0	1.049	0	$ 0.08900	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.08900	$ -
Sentinel Lighting	0	1.049	0	$ 0.08900	$ -
TOTAL	509,295,934		534,047,716		$ 47,530,247

Electricity - Commodity Non-RPP	2014	2014 Loss Factor	2014		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	81,779,331	1.049	85,753,806	$ 0.02651	$ 2,273,435
General Service < 50 kW	24,643,488	1.049	25,841,161	$ 0.02651	$ 685,080
General Service 50 to 999 kW	349,725,891	1.049	366,722,569	$ 0.02651	$ 9,722,249
General Service 1,000 to 4,999 kW	72,223,027	1.049	75,733,066	$ 0.02651	$ 2,007,773
Large User >5000 kw	43,637,356	1.049	45,758,132	$ 0.02651	$ 1,213,102
Street Lighting	9,157,883	1.049	9,602,956	$ 0.02651	$ 254,586
Unmetered Scattered Load	2,720,085	1.049	2,852,281	$ 0.02651	$ 75,617
Sentinel Lighting	34,756	1.049	36,445	$ 0.02651	$ 966
TOTAL	583,921,816		612,300,416		$ 16,232,807

Electricity - Global Adjustment Non-RPP	2014	2014 Loss Factor	2014		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	81,779,331	1.049	85,753,806	$ 0.06278	$ 5,383,242
General Service < 50 kW	24,643,488	1.049	25,841,161	$ 0.06278	$ 1,622,193
General Service 50 to 999 kW	349,725,891	1.049	366,722,569	$ 0.06278	$ 23,021,210
General Service 1,000 to 4,999 kW	72,223,027	1.049	75,733,066	$ 0.06278	$ 4,754,185
Large User >5000 kw	43,637,356	1.049	45,758,132	$ 0.06278	$ 2,872,492
Street Lighting	9,157,883	1.049	9,602,956	$ 0.06278	$ 602,831
Unmetered Scattered Load	2,720,085	1.049	2,852,281	$ 0.06278	$ 179,053
Sentinel Lighting	34,756	1.049	36,445	$ 0.06278	$ 2,288
TOTAL	583,921,816		612,300,416		$ 38,437,494

Transmission - Network		Volume Metric	2014		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	504,434,153	$ 0.00660	$ 3,329,265
General Service < 50 kW		kWh	141,208,530	$ 0.00600	$ 847,251
General Service 50 to 999 kW		kW	885,168	$ 2.49290	$ 2,206,635
General Service 1,000 to 4,999 kW		kW	159,223	$ 2.80070	$ 445,937
Large User >5000 kw		kW	99,132	$ 2.98410	$ 295,820
Street Lighting		kW	24,692	$ 1.48160	$ 36,584
Unmetered Scattered Load		kWh	2,852,281	$ 0.00600	$ 17,114
Sentinel Lighting		kW	102	$ 1.50720	$ 154
TOTAL					$ 7,178,759

Transmission - Connection		Volume Metric	2014		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	504,434,153	$ 0.00560	$ 2,824,831
General Service < 50 kW		kWh	141,208,530	$ 0.00510	$ 720,164
General Service 50 to 999 kW		kW	885,168	$ 2.08530	$ 1,845,840
General Service 1,000 to 4,999 kW		kW	159,223	$ 2.33360	$ 371,564
Large User >5000 kw		kW	99,132	$ 2.54630	$ 252,420
Street Lighting		kW	24,692	$ 2.12000	$ 52,347
Unmetered Scattered Load		kWh	2,852,281	$ 0.00510	$ 14,547
Sentinel Lighting		kW	102	$ 2.15660	$ 220
TOTAL					$ 6,081,932

Wholesale Market Service			2014		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			504,434,153	$ 0.00520	$ 2,623,058
General Service < 50 kW			141,208,530	$ 0.00520	$ 734,284
General Service 50 to 999 kW			366,722,569	$ 0.00520	$ 1,906,957
General Service 1,000 to 4,999 kW			75,733,066	$ 0.00520	$ 393,812
Large User >5000 kw			45,758,132	$ 0.00520	$ 237,942
Street Lighting			9,602,956	$ 0.00520	$ 49,935
Unmetered Scattered Load			2,852,281	$ 0.00520	$ 14,832
Sentinel Lighting			36,445	$ 0.00520	$ 190
TOTAL			1,146,348,132		$ 5,961,010

Rural Rate Assistance			2014		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			504,434,153	$ 0.00127	$ 638,950
General Service < 50 kW			141,208,530	$ 0.00127	$ 178,864
General Service 50 to 999 kW			366,722,569	$ 0.00127	$ 464,515
General Service 1,000 to 4,999 kW			75,733,066	$ 0.00127	$ 95,929
Large User >5000 kw			45,758,132	$ 0.00127	$ 57,960
Street Lighting			9,602,956	$ 0.00127	$ 12,164
Unmetered Scattered Load			2,852,281	$ 0.00127	$ 3,613
Sentinel Lighting			36,445	$ 0.00127	$ 46
TOTAL			1,146,348,132		$ 1,452,041

Smart Meter Entity Charge			2014		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			50,177	$ 0.78800	$ 474,472
General Service < 50 kW			3,924	$ 0.78800	$ 37,105
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			54,101		$ 511,577

Ontario Clean Energy Benefit			2014		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			54,335,332	10%	-$ 5,433,533
General Service < 50 kW			15,055,532	10%	-$ 1,505,553
General Service 50 to 999 kW			39,167,406	10%	-$ 3,916,741
General Service 1,000 to 4,999 kW			8,069,199	0%	$ -
Large User >5000 kw			4,929,736	0%	$ -
Street Lighting			1,008,447	0%	$ -
Unmetered Scattered Load			304,776	0%	$ -
Sentinel Lighting			3,863	0%	$ -
TOTAL			122,874,291		-$ 10,855,827

Summary	2014
4705-Power Purchased	$ 63,763,054
4705-Smart Meter Entity Charge	$ 511,577
4705-Ontario Clean Energy Benefit	-$ 10,855,827
4708-Charges-Global Adjustment	$ 38,437,494
4708-Charges-WMS	$ 5,961,010
4714-Charges-NW	$ 7,178,759
4716-Charges-CN	$ 6,081,932
4730-Rural Rate Assistance	$ 1,452,041
4750-Low Voltage	$ -
TOTAL	$ 112,530,041

TABLE 2-17 - 2015 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	483,663,532	0	83.0%
General Service < 50 kW	137,144,452	0	81.7%
General Service 50 to 999 kW	365,803,341	925,860	0.0%
General Service 1,000 to 4,999 kW	66,360,781	146,299	0.0%
Large User >5000 kw	44,988,087	102,200	0.0%
Street Lighting	6,898,975	18,602	0.0%
Unmetered Scattered Load	2,688,072	0	0.0%
Sentinel Lighting	33,730	99	0.0%
TOTAL	1,107,580,970	1,193,061	

Electricity - Commodity RPP	2015	2015 Loss Factor	2015		
Class per Load Forecast RPP	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	401,440,732	1.049	420,950,751	$ 0.09516	$ 40,057,674
General Service < 50 kW	112,047,018	1.049	117,492,503	$ 0.09516	$ 11,180,587
General Service 50 to 999 kW	0	1.049	0	$ 0.09516	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.09516	$ -
Large User >5000 kw	0	1.049	0	$ 0.09516	$ -
Street Lighting	0	1.049	0	$ 0.09516	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.09516	$ -
Sentinel Lighting	0	1.049	0	$ 0.09516	$ -
TOTAL	513,487,749		538,443,254		$ 51,238,260

Electricity - Commodity Non-RPP	2015	2015 Loss Factor	2015		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,222,800	1.049	86,218,829	$ 0.02084	$ 1,796,800
General Service < 50 kW	25,097,435	1.049	26,317,170	$ 0.02084	$ 548,450
General Service 50 to 999 kW	365,803,341	1.049	383,581,383	$ 0.02084	$ 7,993,836
General Service 1,000 to 4,999 kW	66,360,781	1.049	69,585,915	$ 0.02084	$ 1,450,170
Large User >5000 kw	44,988,087	1.049	47,174,508	$ 0.02084	$ 983,117
Street Lighting	6,898,975	1.049	7,234,265	$ 0.02084	$ 150,762
Unmetered Scattered Load	2,688,072	1.049	2,818,712	$ 0.02084	$ 58,742
Sentinel Lighting	33,730	1.049	35,369	$ 0.02084	$ 737
TOTAL	594,093,221		622,966,152		$ 12,982,615

Electricity - Global Adjustment Non-RPP	2015	2015 Loss Factor	2015		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,222,800	1.049	86,218,829	$ 0.07488	$ 6,456,066
General Service < 50 kW	25,097,435	1.049	26,317,170	$ 0.07488	$ 1,970,630
General Service 50 to 999 kW	365,803,341	1.049	383,581,383	$ 0.07488	$ 28,722,574
General Service 1,000 to 4,999 kW	66,360,781	1.049	69,585,915	$ 0.07488	$ 5,210,593
Large User >5000 kw	44,988,087	1.049	47,174,508	$ 0.07488	$ 3,532,427
Street Lighting	6,898,975	1.049	7,234,265	$ 0.07488	$ 541,702
Unmetered Scattered Load	2,688,072	1.049	2,818,712	$ 0.07488	$ 211,065
Sentinel Lighting	33,730	1.049	35,369	$ 0.07488	$ 2,648
TOTAL	594,093,221		622,966,152		$ 46,647,705

Transmission - Network		Volume Metric	2015		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	507,169,580	$ 0.00660	$ 3,347,319
General Service < 50 kW		kWh	143,809,673	$ 0.00600	$ 862,858
General Service 50 to 999 kW		kW	925,860	$ 2.49290	$ 2,308,077
General Service 1,000 to 4,999 kW		kW	146,299	$ 2.80070	$ 409,741
Large User >5000 kw		kW	102,200	$ 2.98410	$ 304,977
Street Lighting		kW	18,602	$ 1.48160	$ 27,560
Unmetered Scattered Load		kWh	2,818,712	$ 0.00600	$ 16,912
Sentinel Lighting		kW	99	$ 1.50720	$ 149
TOTAL					$ 7,277,593

Transmission - Connection		Volume Metric	2015		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	507,169,580	$ 0.00560	$ 2,840,150
33,333		kWh	143,809,673	$ 0.00510	$ 733,429
General Service 50 to 999 kW		kW	925,860	$ 2.08530	$ 1,930,697
General Service 1,000 to 4,999 kW		kW	146,299	$ 2.33360	$ 341,404
Large User >5000 kw		kW	102,200	$ 2.54630	$ 260,233
Street Lighting		kW	18,602	$ 2.12000	$ 39,435
Unmetered Scattered Load		kWh	2,818,712	$ 0.00510	$ 14,375
Sentinel Lighting		kW	99	$ 2.15660	$ 213
TOTAL					$ 6,159,937

Wholesale Market Service			2015		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			507,169,580	$ 0.00520	$ 2,637,282
General Service < 50 kW			143,809,673	$ 0.00520	$ 747,810
General Service 50 to 999 kW			383,581,383	$ 0.00520	$ 1,994,623
General Service 1,000 to 4,999 kW			69,585,915	$ 0.00520	$ 361,847
Large User >5000 kw			47,174,508	$ 0.00520	$ 245,307
Street Lighting			7,234,265	$ 0.00520	$ 37,618
Unmetered Scattered Load			2,818,712	$ 0.00520	$ 14,657
Sentinel Lighting			35,369	$ 0.00520	$ 184
TOTAL			1,161,409,406		$ 6,039,329

Rural Rate Assistance			2015		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			507,169,580	$ 0.00130	$ 659,320
General Service < 50 kW			143,809,673	$ 0.00130	$ 186,953
General Service 50 to 999 kW			383,581,383	$ 0.00130	$ 498,656
General Service 1,000 to 4,999 kW			69,585,915	$ 0.00130	$ 90,462
Large User >5000 kw			47,174,508	$ 0.00130	$ 61,327
Street Lighting			7,234,265	$ 0.00130	$ 9,405
Unmetered Scattered Load			2,818,712	$ 0.00130	$ 3,664
Sentinel Lighting			35,369	$ 0.00130	$ 46
TOTAL			1,161,409,406		$ 1,509,832

Smart Meter Entity Charge			2015		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			51,682	$ 0.78800	$ 488,707
General Service < 50 kW			4,042	$ 0.78800	$ 38,218
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			55,724		$ 526,925

Ontario Clean Energy Benefit			2015		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			57,794,611	10%	-$ 5,779,461
General Service < 50 kW			16,230,716	10%	-$ 1,623,072
General Service 50 to 999 kW			43,448,463	10%	-$ 4,344,846
General Service 1,000 to 4,999 kW			7,864,217	0%	$ -
Large User >5000 kw			5,387,388	0%	$ -
Street Lighting			806,482	0%	$ -
Unmetered Scattered Load			319,416	0%	$ -
Sentinel Lighting			3,978	0%	$ -
TOTAL			131,855,271		-$ 11,747,379

Summary	2015
4705-Power Purchased	$ 64,220,875
4705-Smart Meter Entity Charge	$ 526,925
4705-Ontario Clean Energy Benefit	-$ 11,747,379
4708-Charges-Global Adjustment	$ 46,647,705
4708-Charges-WMS	$ 6,039,329
4714-Charges-NW	$ 7,277,593
4716-Charges-CN	$ 6,159,937
4730-Rural Rate Assistance	$ 1,509,832
4750-Low Voltage	$ -
TOTAL	$ 120,634,817

TABLE 2-18 - 2016 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	486,758,735	0	83.0%
General Service < 50 kW	139,823,685	0	81.7%
General Service 50 to 999 kW	383,057,156	969,530	0.0%
General Service 1,000 to 4,999 kW	61,520,302	135,628	0.0%
Large User >5000 kw	46,339,336	105,270	0.0%
Street Lighting	4,602,545	12,410	0.0%
Unmetered Scattered Load	2,654,071	0	0.0%
Sentinel Lighting	32,705	96	0.0%
TOTAL	1,124,788,537	1,222,934	

Electricity - Commodity RPP	2016 Forecasted Metered kWhs	2016 Loss Factor	2016		
Class per Load Forecast RPP			kWhs Purchased	Price	Cost of Power
Residential	404,009,750	1.049	423,644,624	$ 0.09516	$ 40,314,022
General Service < 50 kW	114,235,951	1.049	119,787,818	$ 0.09516	$ 11,399,009
General Service 50 to 999 kW	0	1.049	0	$ 0.09516	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.09516	$ -
Large User >5000 kw	0	1.049	0	$ 0.09516	$ -
Street Lighting	0	1.049	0	$ 0.09516	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.09516	$ -
Sentinel Lighting	0	1.049	0	$ 0.09516	$ -
TOTAL	518,245,701		543,432,442		$ 51,713,031

Electricity - Commodity Non-RPP	2016 Forecasted Metered kWhs	2016 Loss Factor	2016		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential	82,748,985	1.049	86,770,586	$ 0.02084	$ 1,808,299
General Service < 50 kW	25,587,734	1.049	26,831,298	$ 0.02084	$ 559,164
General Service 50 to 999 kW	383,057,156	1.049	401,673,734	$ 0.02084	$ 8,370,881
General Service 1,000 to 4,999 kW	61,520,302	1.049	64,510,189	$ 0.02084	$ 1,344,392
Large User >5000 kw	46,339,336	1.049	48,591,428	$ 0.02084	$ 1,012,645
Street Lighting	4,602,545	1.049	4,826,229	$ 0.02084	$ 100,579
Unmetered Scattered Load	2,654,071	1.049	2,783,059	$ 0.02084	$ 57,999
Sentinel Lighting	32,705	1.049	34,295	$ 0.02084	$ 715
TOTAL	606,542,836		636,020,817		$ 13,254,674

Electricity - Global Adjustment Non-RPP	2016 Forecasted Metered kWhs	2016 Loss Factor	2016		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential	82,748,985	1.049	86,770,586	$ 0.07488	$ 6,497,381
General Service < 50 kW	25,587,734	1.049	26,831,298	$ 0.07488	$ 2,009,128
General Service 50 to 999 kW	383,057,156	1.049	401,673,734	$ 0.07488	$ 30,077,329
General Service 1,000 to 4,999 kW	61,520,302	1.049	64,510,189	$ 0.07488	$ 4,830,523
Large User >5000 kw	46,339,336	1.049	48,591,428	$ 0.07488	$ 3,638,526
Street Lighting	4,602,545	1.049	4,826,229	$ 0.07488	$ 361,388
Unmetered Scattered Load	2,654,071	1.049	2,783,059	$ 0.07488	$ 208,395
Sentinel Lighting	32,705	1.049	34,295	$ 0.07488	$ 2,568
TOTAL	606,542,836		636,020,817		$ 47,625,239

Transmission - Network		Volume Metric	2016		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	510,415,210	$ 0.00660	$ 3,368,740
General Service < 50 kW		kWh	146,619,116	$ 0.00600	$ 879,715
General Service 50 to 999 kW		kW	969,530	$ 2.49290	$ 2,416,942
General Service 1,000 to 4,999 kW		kW	135,628	$ 2.80070	$ 379,853
Large User >5000 kw		kW	105,270	$ 2.98410	$ 314,137
Street Lighting		kW	12,410	$ 1.48160	$ 18,386
Unmetered Scattered Load		kWh	2,783,059	$ 0.00600	$ 16,698
Sentinel Lighting		kW	96	$ 1.50720	$ 145
TOTAL					$ 7,394,616

Transmission - Connection		Volume Metric	2016		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	510,415,210	$ 0.00560	$ 2,858,325
General Service < 50 kW		kWh	146,619,116	$ 0.00510	$ 747,757
General Service 50 to 999 kW		kW	969,530	$ 2.08530	$ 2,021,762
General Service 1,000 to 4,999 kW		kW	135,628	$ 2.33360	$ 316,502
Large User >5000 kw		kW	105,270	$ 2.54630	$ 268,049
Street Lighting		kW	12,410	$ 2.12000	$ 26,309
Unmetered Scattered Load		kWh	2,783,059	$ 0.00510	$ 14,194
Sentinel Lighting		kW	96	$ 2.15660	$ 207
TOTAL					$ 6,253,104

Wholesale Market Service			2016		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			510,415,210	$ 0.00520	$ 2,654,159
General Service < 50 kW			146,619,116	$ 0.00520	$ 762,419
General Service 50 to 999 kW			401,673,734	$ 0.00520	$ 2,088,703
General Service 1,000 to 4,999 kW			64,510,189	$ 0.00520	$ 335,453
Large User >5000 kw			48,591,428	$ 0.00520	$ 252,675
Street Lighting			4,826,229	$ 0.00520	$ 25,096
Unmetered Scattered Load			2,783,059	$ 0.00520	$ 14,472
Sentinel Lighting			34,295	$ 0.00520	$ 178
TOTAL			1,179,453,259		$ 6,133,157

Rural Rate Assistance			2016		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			510,415,210	$ 0.00130	$ 663,540
General Service < 50 kW			146,619,116	$ 0.00130	$ 190,605
General Service 50 to 999 kW			401,673,734	$ 0.00130	$ 522,176
General Service 1,000 to 4,999 kW			64,510,189	$ 0.00130	$ 83,863
Large User >5000 kw			48,591,428	$ 0.00130	$ 63,169
Street Lighting			4,826,229	$ 0.00130	$ 6,274
Unmetered Scattered Load			2,783,059	$ 0.00130	$ 3,618
Sentinel Lighting			34,295	$ 0.00130	$ 45
TOTAL			1,179,453,259		$ 1,533,289

Smart Meter Entity Charge			2016		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			53,233	$ 0.78800	$ 503,368
General Service < 50 kW			4,163	$ 0.78800	$ 39,365
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			57,396		$ 542,733

Ontario Clean Energy Benefit			2016		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			58,164,467	10%	-$ 5,816,447
General Service < 50 kW			16,547,797	10%	-$ 1,654,780
General Service 50 to 999 kW			45,497,793	10%	-$ 4,549,779
General Service 1,000 to 4,999 kW			7,290,587	0%	$ -
Large User >5000 kw			5,549,202	0%	$ -
Street Lighting			538,032	0%	$ -
Unmetered Scattered Load			315,376	0%	$ -
Sentinel Lighting			3,857	0%	$ -
TOTAL			133,907,111		-$ 12,021,006

Summary	2016
4705-Power Purchased	$ 64,967,705
4705-Smart Meter Entity Charge	$ 542,733
4705-Ontario Clean Energy Benefit	-$ 12,021,006
4708-Charges-Global Adjustment	$ 47,625,239
4708-Charges-WMS	$ 6,133,157
4714-Charges-NW	$ 7,394,616
4716-Charges-CN	$ 6,253,104
4730-Rural Rate Assistance	$ 1,533,289
4750-Low Voltage	$ -
TOTAL	$ 122,428,838

TABLE 2-19 - 2017 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	485,640,571	0	83.0%
General Service < 50 kW	141,342,094	0	81.7%
General Service 50 to 999 kW	397,878,346	1,007,043	0.0%
General Service 1,000 to 4,999 kW	56,063,419	123,598	0.0%
Large User >5000 kw	47,612,969	108,164	0.0%
Street Lighting	4,729,452	12,752	0.0%
Unmetered Scattered Load	2,614,011	0	0.0%
Sentinel Lighting	31,633	93	0.0%
TOTAL	1,135,912,494	1,251,649	

Electricity - Commodity RPP	2017	2017 Loss Factor	2017		
Class per Load Forecast RPP	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	403,081,674	1.049	422,671,443	$ 0.09516	$ 40,221,415
General Service < 50 kW	115,476,491	1.049	121,088,649	$ 0.09516	$ 11,522,796
General Service 50 to 999 kW	0	1.049	0	$ 0.09516	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.09516	$ -
Large User >5000 kw	0	1.049	0	$ 0.09516	$ -
Street Lighting	0	1.049	0	$ 0.09516	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.09516	$ -
Sentinel Lighting	0	1.049	0	$ 0.09516	$ -
TOTAL	518,558,165		543,760,092		$ 51,744,210

Electricity - Commodity Non-RPP	2017	2017 Loss Factor	2017		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,558,897	1.049	86,571,259	$ 0.02084	$ 1,804,145
General Service < 50 kW	25,865,603	1.049	27,122,672	$ 0.02084	$ 565,236
General Service 50 to 999 kW	397,878,346	1.049	417,215,233	$ 0.02084	$ 8,694,765
General Service 1,000 to 4,999 kW	56,063,419	1.049	58,788,101	$ 0.02084	$ 1,225,144
Large User >5000 kw	47,612,969	1.049	49,926,959	$ 0.02084	$ 1,040,478
Street Lighting	4,729,452	1.049	4,959,304	$ 0.02084	$ 103,352
Unmetered Scattered Load	2,614,011	1.049	2,741,051	$ 0.02084	$ 57,124
Sentinel Lighting	31,633	1.049	33,170	$ 0.02084	$ 691
TOTAL	617,354,329		647,357,750		$ 13,490,936

Electricity - Global Adjustment Non-RPP	2017	2017 Loss Factor	2017		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,558,897	1.049	86,571,259	$ 0.07488	$ 6,482,456
General Service < 50 kW	25,865,603	1.049	27,122,672	$ 0.07488	$ 2,030,946
General Service 50 to 999 kW	397,878,346	1.049	417,215,233	$ 0.07488	$ 31,241,077
General Service 1,000 to 4,999 kW	56,063,419	1.049	58,788,101	$ 0.07488	$ 4,402,053
Large User >5000 kw	47,612,969	1.049	49,926,959	$ 0.07488	$ 3,738,531
Street Lighting	4,729,452	1.049	4,959,304	$ 0.07488	$ 371,353
Unmetered Scattered Load	2,614,011	1.049	2,741,051	$ 0.07488	$ 205,250
Sentinel Lighting	31,633	1.049	33,170	$ 0.07488	$ 2,484
TOTAL	617,354,329		647,357,750		$ 48,474,148

Transmission - Network		Volume Metric	2017		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	509,242,703	$ 0.00660	$ 3,361,002
General Service < 50 kW		kWh	148,211,320	$ 0.00600	$ 889,268
General Service 50 to 999 kW		kW	1,007,043	$ 2.49290	$ 2,510,458
General Service 1,000 to 4,999 kW		kW	123,598	$ 2.80070	$ 346,160
Large User >5000 kw		kW	108,164	$ 2.98410	$ 322,771
Street Lighting		kW	12,752	$ 1.48160	$ 18,893
Unmetered Scattered Load		kWh	2,741,051	$ 0.00600	$ 16,446
Sentinel Lighting		kW	93	$ 1.50720	$ 140
TOTAL					$ 7,465,138

Transmission - Connection		Volume Metric	2017		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	509,242,703	$ 0.00560	$ 2,851,759
General Service < 50 kW		kWh	148,211,320	$ 0.00510	$ 755,878
General Service 50 to 999 kW		kW	1,007,043	$ 2.08530	$ 2,099,987
General Service 1,000 to 4,999 kW		kW	123,598	$ 2.33360	$ 288,428
Large User >5000 kw		kW	108,164	$ 2.54630	$ 275,417
Street Lighting		kW	12,752	$ 2.12000	$ 27,034
Unmetered Scattered Load		kWh	2,741,051	$ 0.00510	$ 13,979
Sentinel Lighting		kW	93	$ 2.15660	$ 200
TOTAL					$ 6,312,682

Wholesale Market Service			2017		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			509,242,703	$ 0.00520	$ 2,648,062
General Service < 50 kW			148,211,320	$ 0.00520	$ 770,699
General Service 50 to 999 kW			417,215,233	$ 0.00520	$ 2,169,519
General Service 1,000 to 4,999 kW			58,788,101	$ 0.00520	$ 305,698
Large User >5000 kw			49,926,959	$ 0.00520	$ 259,620
Street Lighting			4,959,304	$ 0.00520	$ 25,788
Unmetered Scattered Load			2,741,051	$ 0.00520	$ 14,253
Sentinel Lighting			33,170	$ 0.00520	$ 172
TOTAL			1,191,117,842		$ 6,193,813

Rural Rate Assistance			2017		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			509,242,703	$ 0.00130	$ 662,016
General Service < 50 kW			148,211,320	$ 0.00130	$ 192,675
General Service 50 to 999 kW			417,215,233	$ 0.00130	$ 542,380
General Service 1,000 to 4,999 kW			58,788,101	$ 0.00130	$ 76,425
Large User >5000 kw			49,926,959	$ 0.00130	$ 64,905
Street Lighting			4,959,304	$ 0.00130	$ 6,447
Unmetered Scattered Load			2,741,051	$ 0.00130	$ 3,563
Sentinel Lighting			33,170	$ 0.00130	$ 43
TOTAL			1,191,117,842		$ 1,548,453

Smart Meter Entity Charge			2017		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			54,830	$ 0.78800	$ 518,468
General Service < 50 kW			4,288	$ 0.78800	$ 40,545
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			59,117		$ 559,014

Ontario Clean Energy Benefit			2017		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			58,030,854	10%	-$ 5,803,085
General Service < 50 kW			16,727,497	10%	-$ 1,672,750
General Service 50 to 999 kW			47,258,186	10%	-$ 4,725,819
General Service 1,000 to 4,999 kW			6,643,908	0%	$ -
Large User >5000 kw			5,701,721	0%	$ -
Street Lighting			552,867	0%	$ -
Unmetered Scattered Load			310,616	0%	$ -
Sentinel Lighting			3,730	0%	$ -
TOTAL			135,229,380		-$ 12,201,654

Summary	2017
4705-Power Purchased	$ 65,235,146
4705-Smart Meter Entity Charge	$ 559,014
4705-Ontario Clean Energy Benefit	-$ 12,201,654
4708-Charges-Global Adjustment	$ 48,474,148
4708-Charges-WMS	$ 6,193,813
4714-Charges-NW	$ 7,465,138
4716-Charges-CN	$ 6,312,682
4730-Rural Rate Assistance	$ 1,548,453
4750-Low Voltage	$ -
TOTAL	$ 123,586,740

TABLE 2-20 - 2018 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	485,086,336	0	83.0%
General Service < 50 kW	143,067,915	0	81.7%
General Service 50 to 999 kW	413,841,565	1,047,447	0.0%
General Service 1,000 to 4,999 kW	51,546,101	113,639	0.0%
Large User >5000 kw	48,880,609	111,043	0.0%
Street Lighting	4,858,993	13,101	0.0%
Unmetered Scattered Load	2,572,397	0	0.0%
Sentinel Lighting	30,570	90	0.0%
TOTAL	1,149,884,488	1,285,320	

Electricity - Commodity RPP	2018 Forecasted Metered kWhs	2018 Loss Factor	2018		
Class per Load Forecast RPP			kWhs Purchased	Price	Cost of Power
Residential	402,621,659	1.049	422,189,072	$ 0.09516	$ 40,175,512
General Service < 50 kW	116,886,486	1.049	122,567,170	$ 0.09516	$ 11,663,492
General Service 50 to 999 kW	0	1.049	0	$ 0.09516	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.09516	$ -
Large User >5000 kw	0	1.049	0	$ 0.09516	$ -
Street Lighting	0	1.049	0	$ 0.09516	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.09516	$ -
Sentinel Lighting	0	1.049	0	$ 0.09516	$ -
TOTAL	519,508,145		544,756,241		$ 51,839,004

Electricity - Commodity Non-RPP	2018 Forecasted Metered kWhs	2018 Loss Factor	2018		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential	82,464,677	1.049	86,472,460	$ 0.02084	$ 1,802,086
General Service < 50 kW	26,181,428	1.049	27,453,846	$ 0.02084	$ 572,138
General Service 50 to 999 kW	413,841,565	1.049	433,954,266	$ 0.02084	$ 9,043,607
General Service 1,000 to 4,999 kW	51,546,101	1.049	54,051,242	$ 0.02084	$ 1,126,428
Large User >5000 kw	48,880,609	1.049	51,256,207	$ 0.02084	$ 1,068,179
Street Lighting	4,858,993	1.049	5,095,140	$ 0.02084	$ 106,183
Unmetered Scattered Load	2,572,397	1.049	2,697,416	$ 0.02084	$ 56,214
Sentinel Lighting	30,570	1.049	32,056	$ 0.02084	$ 668
TOTAL	630,376,343		661,012,633		$ 13,775,503

Electricity - Global Adjustment Non-RPP	2018 Forecasted Metered kWhs	2018 Loss Factor	2018		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential	82,464,677	1.049	86,472,460	$ 0.07488	$ 6,475,058
General Service < 50 kW	26,181,428	1.049	27,453,846	$ 0.07488	$ 2,055,744
General Service 50 to 999 kW	413,841,565	1.049	433,954,266	$ 0.07488	$ 32,494,495
General Service 1,000 to 4,999 kW	51,546,101	1.049	54,051,242	$ 0.07488	$ 4,047,357
Large User >5000 kw	48,880,609	1.049	51,256,207	$ 0.07488	$ 3,838,065
Street Lighting	4,858,993	1.049	5,095,140	$ 0.07488	$ 381,524
Unmetered Scattered Load	2,572,397	1.049	2,697,416	$ 0.07488	$ 201,982
Sentinel Lighting	30,570	1.049	32,056	$ 0.07488	$ 2,400
TOTAL	630,376,343		661,012,633		$ 49,496,626

Transmission - Network		Volume Metric	2018		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	508,661,532	$ 0.00660	$ 3,357,166
General Service < 50 kW		kWh	150,021,016	$ 0.00600	$ 900,126
General Service 50 to 999 kW		kW	1,047,447	$ 2.49290	$ 2,611,180
General Service 1,000 to 4,999 kW		kW	113,639	$ 2.80070	$ 318,268
Large User >5000 kw		kW	111,043	$ 2.98410	$ 331,364
Street Lighting		kW	13,101	$ 1.48160	$ 19,411
Unmetered Scattered Load		kWh	2,697,416	$ 0.00600	$ 16,184
Sentinel Lighting		kW	90	$ 1.50720	$ 135
TOTAL					$ 7,553,835

Transmission - Connection		Volume Metric	2018		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	508,661,532	$ 0.00560	$ 2,848,505
General Service < 50 kW		kWh	150,021,016	$ 0.00510	$ 765,107
General Service 50 to 999 kW		kW	1,047,447	$ 2.08530	$ 2,184,240
General Service 1,000 to 4,999 kW		kW	113,639	$ 2.33360	$ 265,188
Large User >5000 kw		kW	111,043	$ 2.54630	$ 282,749
Street Lighting		kW	13,101	$ 2.12000	$ 27,775
Unmetered Scattered Load		kWh	2,697,416	$ 0.00510	$ 13,757
Sentinel Lighting		kW	90	$ 2.15660	$ 193
TOTAL					$ 6,387,514

Wholesale Market Service			2018		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			508,661,532	$ 0.00520	$ 2,645,040
General Service < 50 kW			150,021,016	$ 0.00520	$ 780,109
General Service 50 to 999 kW			433,954,266	$ 0.00520	$ 2,256,562
General Service 1,000 to 4,999 kW			54,051,242	$ 0.00520	$ 281,066
Large User >5000 kw			51,256,207	$ 0.00520	$ 266,532
Street Lighting			5,095,140	$ 0.00520	$ 26,495
Unmetered Scattered Load			2,697,416	$ 0.00520	$ 14,027
Sentinel Lighting			32,056	$ 0.00520	$ 167
TOTAL			1,205,768,874		$ 6,269,998

Rural Rate Assistance			2018		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			508,661,532	$ 0.00130	$ 661,260
General Service < 50 kW			150,021,016	$ 0.00130	$ 195,027
General Service 50 to 999 kW			433,954,266	$ 0.00130	$ 564,141
General Service 1,000 to 4,999 kW			54,051,242	$ 0.00130	$ 70,267
Large User >5000 kw			51,256,207	$ 0.00130	$ 66,633
Street Lighting			5,095,140	$ 0.00130	$ 6,624
Unmetered Scattered Load			2,697,416	$ 0.00130	$ 3,507
Sentinel Lighting			32,056	$ 0.00130	$ 42
TOTAL			1,205,768,874		$ 1,567,500

Smart Meter Entity Charge			2018		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			56,474	$ 0.78800	$ 445,019
General Service < 50 kW			4,416	$ 0.78800	$ 34,802
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			60,891		$ 479,821

Ontario Clean Energy Benefit			2018		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			57,964,627	10%	-$ 5,796,463
General Service < 50 kW			16,931,744	10%	-$ 1,693,174
General Service 50 to 999 kW			49,154,225	10%	-$ 4,915,423
General Service 1,000 to 4,999 kW			6,108,574	0%	$ -
Large User >5000 kw			5,853,523	0%	$ -
Street Lighting			568,011	0%	$ -
Unmetered Scattered Load			305,671	0%	$ -
Sentinel Lighting			3,605	0%	$ -
TOTAL			136,889,980		-$ 12,405,060

Summary	2018
4705-Power Purchased	$ 65,614,507
4705-Smart Meter Entity Charge	$ 479,821
4705-Ontario Clean Energy Benefit	-$ 12,405,060
4708-Charges-Global Adjustment	$ 49,496,626
4708-Charges-WMS	$ 6,269,998
4714-Charges-NW	$ 7,553,835
4716-Charges-CN	$ 6,387,514
4730-Rural Rate Assistance	$ 1,567,500
4750-Low Voltage	$ -
TOTAL	$ 124,964,741

TABLE 2-21 - 2019 COST OF POWER FORECAST

Class per Load Forecast	kWh	kW	%RPP
Residential	483,951,299	0	83.0%
General Service < 50 kW	144,664,011	0	81.7%
General Service 50 to 999 kW	430,008,488	1,088,366	0.0%
General Service 1,000 to 4,999 kW	47,307,974	104,295	0.0%
Large User >5000 kw	50,156,999	113,943	0.0%
Street Lighting	4,991,186	13,458	0.0%
Unmetered Scattered Load	2,530,185	0	0.0%
Sentinel Lighting	29,529	87	0.0%
TOTAL	1,163,639,671	1,320,148	

Electricity - Commodity RPP	2019	2019 Loss Factor	2019		
Class per Load Forecast RPP	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	401,679,578	1.049	421,201,205	$ 0.09516	$ 40,081,507
General Service < 50 kW	118,190,497	1.049	123,934,555	$ 0.09516	$ 11,793,612
General Service 50 to 999 kW	0	1.049	0	$ 0.09516	$ -
General Service 1,000 to 4,999 kW	0	1.049	0	$ 0.09516	$ -
Large User >5000 kw	0	1.049	0	$ 0.09516	$ -
Street Lighting	0	1.049	0	$ 0.09516	$ -
Unmetered Scattered Load	0	1.049	0	$ 0.09516	$ -
Sentinel Lighting	0	1.049	0	$ 0.09516	$ -
TOTAL	519,870,075		545,135,761		$ 51,875,119

Electricity - Commodity Non-RPP	2019	2019 Loss Factor	2019		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,271,721	1.049	86,270,126	$ 0.02084	$ 1,797,869
General Service < 50 kW	26,473,514	1.049	27,760,127	$ 0.02084	$ 578,521
General Service 50 to 999 kW	430,008,488	1.049	450,906,901	$ 0.02084	$ 9,396,900
General Service 1,000 to 4,999 kW	47,307,974	1.049	49,607,142	$ 0.02084	$ 1,033,813
Large User >5000 kw	50,156,999	1.049	52,594,629	$ 0.02084	$ 1,096,072
Street Lighting	4,991,186	1.049	5,233,758	$ 0.02084	$ 109,072
Unmetered Scattered Load	2,530,185	1.049	2,653,152	$ 0.02084	$ 55,292
Sentinel Lighting	29,529	1.049	30,964	$ 0.02084	$ 645
TOTAL	643,769,596		675,056,799		$ 14,068,184

Electricity - Global Adjustment Non-RPP	2019	2019 Loss Factor	2019		
Class per Load Forecast	Forecasted Metered kWhs		kWhs Purchased	Price	Cost of Power
Residential	82,271,721	1.049	86,270,126	$ 0.07488	$ 6,459,907
General Service < 50 kW	26,473,514	1.049	27,760,127	$ 0.07488	$ 2,078,678
General Service 50 to 999 kW	430,008,488	1.049	450,906,901	$ 0.07488	$ 33,763,909
General Service 1,000 to 4,999 kW	47,307,974	1.049	49,607,142	$ 0.07488	$ 3,714,583
Large User >5000 kw	50,156,999	1.049	52,594,629	$ 0.07488	$ 3,938,286
Street Lighting	4,991,186	1.049	5,233,758	$ 0.07488	$ 391,904
Unmetered Scattered Load	2,530,185	1.049	2,653,152	$ 0.07488	$ 198,668
Sentinel Lighting	29,529	1.049	30,964	$ 0.07488	$ 2,319
TOTAL	643,769,596		675,056,799		$ 50,548,253

Transmission - Network		Volume Metric	2019		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	507,471,332	$ 0.00660	$ 3,349,311
General Service < 50 kW		kWh	151,694,682	$ 0.00600	$ 910,168
General Service 50 to 999 kW		kW	1,088,366	$ 2.49290	$ 2,713,187
General Service 1,000 to 4,999 kW		kW	104,295	$ 2.80070	$ 292,100
Large User >5000 kw		kW	113,943	$ 2.98410	$ 340,017
Street Lighting		kW	13,458	$ 1.48160	$ 19,939
Unmetered Scattered Load		kWh	2,653,152	$ 0.00600	$ 15,919
Sentinel Lighting		kW	87	$ 1.50720	$ 130
TOTAL					$ 7,640,771

Transmission - Connection		Volume Metric	2019		
Class per Load Forecast			kWhs/kWs Purchased	Price	Cost of Power
Residential		kWh	507,471,332	$ 0.00560	$ 2,841,839
General Service < 50 kW		kWh	151,694,682	$ 0.00510	$ 773,643
General Service 50 to 999 kW		kW	1,088,366	$ 2.08530	$ 2,269,569
General Service 1,000 to 4,999 kW		kW	104,295	$ 2.33360	$ 243,384
Large User >5000 kw		kW	113,943	$ 2.54630	$ 290,133
Street Lighting		kW	13,458	$ 2.12000	$ 28,530
Unmetered Scattered Load		kWh	2,653,152	$ 0.00510	$ 13,531
Sentinel Lighting		kW	87	$ 2.15660	$ 187
TOTAL					$ 6,460,816

Wholesale Market Service			2019		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			507,471,332	$ 0.00520	$ 2,638,851
General Service < 50 kW			151,694,682	$ 0.00520	$ 788,812
General Service 50 to 999 kW			450,906,901	$ 0.00520	$ 2,344,716
General Service 1,000 to 4,999 kW			49,607,142	$ 0.00520	$ 257,957
Large User >5000 kw			52,594,629	$ 0.00520	$ 273,492
Street Lighting			5,233,758	$ 0.00520	$ 27,216
Unmetered Scattered Load			2,653,152	$ 0.00520	$ 13,796
Sentinel Lighting			30,964	$ 0.00520	$ 161
TOTAL			1,220,192,559		$ 6,345,001

Rural Rate Assistance			2019		
Class per Load Forecast			kWhs Purchased	Price	Cost of Power
Residential			507,471,332	$ 0.00130	$ 659,713
General Service < 50 kW			151,694,682	$ 0.00130	$ 197,203
General Service 50 to 999 kW			450,906,901	$ 0.00130	$ 586,179
General Service 1,000 to 4,999 kW			49,607,142	$ 0.00130	$ 64,489
Large User >5000 kw			52,594,629	$ 0.00130	$ 68,373
Street Lighting			5,233,758	$ 0.00130	$ 6,804
Unmetered Scattered Load			2,653,152	$ 0.00130	$ 3,449
Sentinel Lighting			30,964	$ 0.00130	$ 40
TOTAL			1,220,192,559		$ 1,586,250

Smart Meter Entity Charge			2019		
Class per Load Forecast			Customer Connections	Price	Cost of Power
Residential			58,169	$ -	$ -
General Service < 50 kW			4,549	$ -	$ -
General Service 50 to 999 kW			0	$ -	$ -
General Service 1,000 to 4,999 kW			0	$ -	$ -
Large User >5000 kw			0	$ -	$ -
Street Lighting			0	$ -	$ -
Unmetered Scattered Load			0	$ -	$ -
Sentinel Lighting			0	$ -	$ -
TOTAL			62,718		$ -

Ontario Clean Energy Benefit			2019		
Class per Load Forecast			Cost of Power	%	Benefit
Residential			57,828,997	10%	-$ 5,782,900
General Service < 50 kW			17,120,638	10%	-$ 1,712,064
General Service 50 to 999 kW			51,074,459	10%	-$ 5,107,446
General Service 1,000 to 4,999 kW			5,606,326	0%	$ -
Large User >5000 kw			6,006,372	0%	$ -
Street Lighting			583,464	0%	$ -
Unmetered Scattered Load			300,655	0%	$ -
Sentinel Lighting			3,482	0%	$ -
TOTAL			138,524,394		-$ 12,602,409

Summary	2019
4705-Power Purchased	$ 65,943,303
4705-Smart Meter Entity Charge	$ -
4705-Ontario Clean Energy Benefit	-$ 12,602,409
4708-Charges-Global Adjustment	$ 50,548,253
4708-Charges-WMS	$ 6,345,001
4714-Charges-NW	$ 7,640,771
4716-Charges-CN	$ 6,460,816
4730-Rural Rate Assistance	$ 1,586,250
4750-Low Voltage	$ -
TOTAL	$ 125,921,985

GROSS ASSETS – PROPERTY, PLANT, AND EQUIPMENT AND ACCUMULATED DEPRECIATION

Overview

In support of its rate base calculation, OPUCN has attached the information required in the Chapter 2 Filing Requirements for Gross Assets, Accumulated Depreciation and Working Capital.

Gross Assets – By Function

OPUCN's Gross Assets are divided into two principal categories (distribution plant and general plant) as illustrated in Table 2-22. OPUCN has included asset accounts 1805 to 1860, and 1910 in the category of distribution plant, and accounts 1915 to 1980, and 1611 in the category of general plant in accordance with the Uniform System of Accounts ('USoA"). OPUCN does not have any transmission plant assets. Capital contributions have been listed separately.

Detailed amounts categorized by major plant account are provided Tables 2-23 through 2-25 of this Exhibit.

Table 2-22 provides a summary of Gross Assets for the 2011 Actual, 2012 Board-Approved Plan amounts; 2012 and 2013 Actual results; forecast 2014 Bridge Year; and 2015 through 2019 Test Years:

TABLE 2-22 - GROSS ASSETS BY FUNCTION

Description	2011 Actual MIFRS	2012 Board Approved MIFRS	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS
Distribution Plant	160,693,939	169,231,724	169,594,841	178,182,217	187,261,432
General Plant	11,051,057	12,621,057	13,217,942	13,772,128	14,541,551
Capital Contributions	(29,357,707)	(29,249,019)	(30,628,873)	(32,328,140)	(33,963,140)
Other	0	0	0	0	0
Gross Assets less Capital Contributions	142,387,289	152,603,763	152,183,909	159,626,204	167,839,843

Description	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Distribution Plant	201,165,724	210,796,789	221,917,858	232,376,317	241,507,754
General Plant	16,132,298	17,363,857	18,244,679	19,242,351	20,010,265
Capital Contributions	(38,874,140)	(40,329,140)	(41,404,140)	(42,499,140)	(43,604,140)
Other	0	0	0	0	0
Gross Assets less Capital Contributions	178,423,882	187,831,507	198,758,398	209,119,529	217,913,879

Gross Assets – Detailed Breakdown

Section 2.5.1.2 of the Board's Filing Requirements requires that Applicants provide a detailed breakdown by major plant account for each functionalized plant item. OPUCN has included a breakdown of each major plant account according to the Board's USofA in Tables 2-23 through 2-25 in compliance with this requirement. The tables cover historical years and the 2014 Bridge Year, as well as each of the 2015-2019 Test Years.

TABLE 2-23 - GROSS ASSETS DETAILED BREAKDOWN 2011-2012

Description	USA	2011 Actual MIFRS	2012 Actual MIFRS	Variance 2012 Actual Vs 2011 Actual	2012 Board Approved MIFRS	2012 Actual MIFRS	Variance 2012 Actual Vs 2012 Board Approved
Land	1805	293,875	293,875	0	293,875	293,875	0
Buildings	1808	709,412	709,412	0	709,412	709,412	0
Leasehold Improvements	1910	689,468	889,513	200,046	714,468	889,513	175,046
Land and Buildings sub-total		**1,692,756**	**1,892,801**	**200,046**	**1,717,756**	**1,892,801**	**175,046**
Distribution Station Equipment	1820	15,650,967	19,171,881	3,520,915	19,225,396	19,171,881	(53,514)
Distribution Station Equipment sub-total		**15,650,967**	**19,171,881**	**3,520,915**	**19,225,396**	**19,171,881**	**(53,514)**
Poles, Towers & Fixtures	1830	29,012,569	30,605,850	1,593,281	30,409,702	30,605,850	196,148
Overhead Conductors & Devices	1835	17,881,699	18,688,244	806,545	18,359,712	18,688,244	328,531
Underground Conductors & Devices	1845	38,060,389	38,938,391	878,003	39,592,760	38,938,391	(654,369)
Poles and Wires sub-total		**84,954,657**	**88,232,485**	**3,277,828**	**88,362,175**	**88,232,485**	**(129,690)**
Line Transformers	1850	48,776,843	50,434,073	1,657,229	49,923,708	50,434,073	510,364
Line Transformers sub-total		**48,776,843**	**50,434,073**	**1,657,229**	**49,923,708**	**50,434,073**	**510,364**
Meters	1860	9,618,716	9,863,601	244,885	10,002,690	9,863,601	(139,089)
Meters sub-total		**9,618,716**	**9,863,601**	**244,885**	**10,002,690**	**9,863,601**	**(139,089)**
Computer Equipment - Hardware	1920	2,167,954	2,297,730	129,776	2,217,954	2,297,730	79,776
Computer Software	1611	715,690	1,174,804	459,115	765,690	1,174,804	409,115
IT Assets sub-total		**2,883,644**	**3,472,534**	**588,890**	**2,983,644**	**3,472,534**	**488,890**
Office Furniture & Equipment	1915	684,896	691,808	6,911	684,896	691,808	6,911
Transportation Equipment	1930	3,072,834	4,334,938	1,262,104	4,292,834	4,334,938	42,104
Stores Equipment	1935	24,516	24,516	0	24,516	24,516	0
Tools, Shop & Garage Equipment	1940	2,176,145	2,260,872	84,728	2,226,145	2,260,872	34,728
Measurement & Testing Equipment	1945	424,560	439,465	14,905	424,560	439,465	14,905
Communications Equipment	1955	266,585	413,853	147,267	416,585	413,853	(2,733)
Miscellaneous Equipment	1960	95,567	157,645	62,078	95,567	157,645	62,078
Load Management Controls - Customer	1970	107,035	107,035	0	107,035	107,035	0
Load Management Controls - Utility	1975	1,021,693	1,021,693	0	1,071,693	1,021,693	(50,000)
System Supervisor Equipment	1980	293,582	293,582	0	293,582	293,582	0
Equipment sub-total		**8,167,413**	**9,745,407**	**1,577,994**	**9,637,413**	**9,745,407**	**107,994**
Gross Assets Total		**171,744,996**	**182,812,782**	**11,067,787**	**181,852,781**	**182,812,782**	**960,001**
Capital Contributions	1995	(29,357,707)	(30,628,873)	(1,271,166)	(29,249,019)	(30,628,873)	(1,379,854)
Gross Assets Less Capital Contributions		142,387,289	152,183,909	9,796,620	152,603,763	152,183,909	(419,853)

TABLE 2-24 - GROSS ASSETS DETAILED BREAKDOWN 2013-2015

Description	USA	2013 Actual MIFRS	Variance 2013 Actual Vs 2012 Actual	2014 Bridge Year MIFRS	Variance 2014 Bridge Vs 2013 Actual	2015 Test Year MIFRS	Variance 2015 Test Year Vs 2014 Bridge
Land	1805	293,875	0	293,875	0	293,875	0
Buildings	1808	709,412	0	709,412	0	1,459,412	750,000
Leasehold Improvements	1910	907,778	18,265	1,087,778	180,000	1,335,278	247,500
Land and Buildings sub-total		**1,911,066**	**18,265**	**2,091,066**	**180,000**	**3,088,566**	**997,500**
Distribution Station Equipment	1820	18,975,879	(196,002)	19,680,347	704,468	21,421,119	1,740,772
Distribution Station Equipment sub-total		**18,975,879**	**(196,002)**	**19,680,347**	**704,468**	**21,421,119**	**1,740,772**
Poles, Towers & Fixtures	1830	34,446,424	3,840,574	36,604,983	2,158,559	41,568,094	4,963,111
Overhead Conductors & Devices	1835	19,319,701	631,457	21,199,769	1,880,068	23,523,238	2,323,469
Underground Conductors & Devices	1845	41,089,183	2,150,792	44,613,093	3,523,910	47,464,420	2,851,327
Poles and Wires sub-total		**94,855,308**	**6,622,823**	**102,417,845**	**7,562,537**	**112,555,752**	**10,137,908**
Line Transformers	1850	52,004,337	1,570,264	52,362,123	357,787	52,871,429	509,306
Line Transformers sub-total		**52,004,337**	**1,570,264**	**52,362,123**	**357,787**	**52,871,429**	**509,306**
Meters	1860	10,435,627	572,026	10,710,050	274,424	11,228,857	518,807
Meters sub-total		**10,435,627**	**572,026**	**10,710,050**	**274,424**	**11,228,857**	**518,807**
Computer Equipment - Hardware	1920	2,539,314	241,584	2,725,314	186,000	2,990,491	265,177
Computer Software	1611	1,552,176	377,372	1,906,176	354,000	2,644,767	738,590
IT Assets sub-total		**4,091,490**	**618,956**	**4,631,490**	**540,000**	**5,635,258**	**1,003,768**
Office Furniture & Equipment	1915	722,939	31,131	742,939	20,000	770,439	27,500
Transportation Equipment	1930	4,103,335	(231,603)	4,156,241	52,906	4,576,241	420,000
Stores Equipment	1935	24,516	0	24,516	0	24,516	0
Tools, Shop & Garage Equipment	1940	2,373,125	112,253	2,523,184	150,058	2,654,116	130,932
Measurement & Testing Equipment	1945	458,634	19,169	465,093	6,459	473,641	8,547
Communications Equipment	1955	418,133	4,280	418,133	0	418,133	0
Miscellaneous Equipment	1960	157,645	0	157,645	0	157,645	0
Load Management Controls - Customer	1970	107,035	0	107,035	0	107,035	0
Load Management Controls - Utility	1975	1,021,693	0	1,021,693	0	1,021,693	0
System Supervisor Equipment	1980	293,582	0	293,582	0	293,582	0
Equipment sub-total		**9,680,637**	**(64,770)**	**9,910,061**	**229,424**	**10,497,041**	**586,979**
Gross Assets Total		**191,954,344**	**9,141,562**	**201,802,983**	**9,848,639**	**217,298,022**	**15,495,039**
Capital Contributions	1995	(32,328,140)	(1,699,267)	(33,963,140)	(1,635,000)	(38,874,140)	(4,911,000)
Gross Assets Less Capital Contributions		159,626,204	7,442,295	167,839,843	8,213,639	178,423,882	10,584,039

TABLE 2-25 - GROSS ASSETS DETAILED BREAKDOWN 2016-2019

Description	USA	2016 Test Year MIFRS	Variance 2016 Test Year Vs 2015 Test Year	2017 Test Year MIFRS	Variance 2017 Test Year Vs 2016 Test Year	2018 Test Year MIFRS	Variance 2018 Test Year Vs 2017 Test Year	2019 Test Year MIFRS	Variance 2019 Test Year Vs 2018 Test Year
Land	1805	293,875	0	293,875	0	293,875	0	293,875	0
Buildings	1808	2,459,412	1,000,000	2,459,412	0	2,459,412	0	2,459,412	0
Leasehold Improvements	1910	1,425,278	90,000	1,470,278	45,000	1,515,278	45,000	1,560,278	45,000
Land and Buildings sub-total		**4,178,566**	**1,090,000**	**4,223,566**	**45,000**	**4,268,566**	**45,000**	**4,313,566**	**45,000**
Distribution Station Equipment	1820	23,446,291	2,025,171	27,067,594	3,621,304	28,445,877	1,378,283	30,652,988	2,207,111
Distribution Station Equipment sub-total		**23,446,291**	**2,025,171**	**27,067,594**	**3,621,304**	**28,445,877**	**1,378,283**	**30,652,988**	**2,207,111**
Poles, Towers & Fixtures	1830	43,766,948	2,198,854	46,191,413	2,424,465	48,497,535	2,306,122	50,739,656	2,242,121
Overhead Conductors & Devices	1835	24,687,685	1,164,447	26,315,098	1,627,413	28,027,968	1,712,869	29,519,197	1,491,229
Underground Conductors & Devices	1845	49,777,582	2,313,162	52,138,960	2,361,378	56,272,123	4,133,163	58,542,608	2,270,485
Poles and Wires sub-total		**118,232,216**	**5,676,464**	**124,645,472**	**6,413,256**	**132,797,627**	**8,152,155**	**138,801,461**	**6,003,834**
Line Transformers	1850	53,188,254	316,825	53,558,650	370,396	53,917,166	358,516	54,268,263	351,098
Line Transformers sub-total		**53,188,254**	**316,825**	**53,558,650**	**370,396**	**53,917,166**	**358,516**	**54,268,263**	**351,098**
Meters	1860	11,751,463	522,606	12,422,576	671,113	12,947,082	524,506	13,471,476	524,394
Meters sub-total		**11,751,463**	**522,606**	**12,422,576**	**671,113**	**12,947,082**	**524,506**	**13,471,476**	**524,394**
Computer Equipment - Hardware	1920	3,162,896	172,405	3,260,051	97,155	3,520,099	260,048	3,618,148	98,048
Computer Software	1611	3,089,793	445,026	3,224,828	135,035	3,466,249	241,421	3,659,670	193,421
IT Assets sub-total		**6,252,688**	**617,431**	**6,484,879**	**232,191**	**6,986,349**	**501,470**	**7,277,818**	**291,470**
Office Furniture & Equipment	1915	780,439	10,000	785,439	5,000	790,439	5,000	795,439	5,000
Transportation Equipment	1930	4,991,241	415,000	5,431,241	440,000	5,621,241	190,000	5,791,241	170,000
Stores Equipment	1935	24,516	0	24,516	0	24,516	0	24,516	0
Tools, Shop & Garage Equipment	1940	2,784,573	130,457	2,919,736	135,164	3,056,805	137,068	3,194,254	137,449
Measurement & Testing Equipment	1945	532,312	58,672	600,780	68,468	732,964	132,184	865,009	132,045
Communications Equipment	1955	418,133	0	418,133	0	450,083	31,950	482,033	31,950
Miscellaneous Equipment	1960	157,645	0	157,645	0	157,645	0	157,645	0
Load Management Controls - Customer	1970	107,035	0	107,035	0	107,035	0	107,035	0
Load Management Controls - Utility	1975	1,021,693	0	1,021,693	0	1,021,693	0	1,021,693	0
System Supervisor Equipment	1980	293,582	0	293,582	0	293,582	0	293,582	0
Equipment sub-total		**11,111,169**	**614,128**	**11,759,801**	**648,632**	**12,256,003**	**496,202**	**12,732,447**	**476,444**
Gross Assets Total		**228,160,647**	**10,862,624**	**240,162,538**	**12,001,891**	**251,618,669**	**11,456,131**	**261,518,019**	**9,899,351**
Capital Contributions	1995	(40,329,140)	(1,455,000)	(41,404,140)	(1,075,000)	(42,499,140)	(1,095,000)	(43,604,140)	(1,105,000)
Gross Assets Less Capital Contributions		187,831,507	9,407,624	198,758,398	10,926,891	209,119,529	10,361,131	217,913,879	8,794,351

VARIANCE ANALYSIS ON GROSS ASSETS

The Gross Asset Variance analysis for the variances identified in the above Tables 2-23 through 2-25 is provided as follows:

2012 Actual vs. 2011 Actual

The total gross assets in 2012 of $182, 812,782 are an increase of $11,067,787 compared with 2011 actuals. This is primarily due to capital additions from renewal of assets (overhead, underground and substation rebuilds and non-distribution type) and more specifically:

- two major substation station rebuilds (MS2 and MS15) involving the replacements of four station power transformers, installation of oil containment bays and replacement of associated underground primary lead cables, reaching end of useful life.
- Reconstruction of underground below grade transformer vaults that were aged and had structural defects, along with the replacements of aged vault transformer and switchgear with new intelligent units with advanced technology.
- Installation of new overhead lines and transformers to service and maintain LTLT customers within Oshawa's service territory.
- Replacement of conventional meters with "smart meters"
- Delivery and in service of new fleet (4 bucket trucks, 2 station vans, 2 pick-ups and a pole trailer)

2012 Actual vs. 2012 Board-Approved

In comparing the 2012 Actuals with 2012 Board – Approved, the increase in gross assets of $960,001 is primarily due to the following capital additions:

- Poles and Line transformer installations related to more than forecasted emergency replacements and service connections

- Two vehicles placed in service in 2012 due to unplanned late delivery end of December 2011
  - Unplanned installation of new telephone system, GIS design software licence and security cameras in substations.

2013 Actual vs. 2012 Actual

Total gross assets in 2013 of $191,954,344 are an increase of $9,141,562 compared with 2012 Actuals. This is primarily due to the following capital additions:

- Underground conduits, cables, transformers, switches and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - Phase 1 of the overhead plant expansion and rebuilds to allow load transfer from Wilson TS to Thornton TS;
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;
  - The reconstruction of two underground below grade transformer vault and replacements of associated transformers and switches/equipment with modernized intelligent units (17 Athol Ave and 7 King St E , Regent Theatre);
  - MS13 - replacement of underground conduits and 13.8kV lead primary cables and riser poles and distribution lines;
  - New residential and commercial subdivision development and service upgrades;
  - Distribution plant expansion to eliminate Long Term Load Transfer (LTLT) customers with HONI and retain Oshawa’s customer within its service territory.

- Distribution station assets from the replacement of the MS13 station power transformer and breaker replacements from air magnetic type to vacuum type breakers;
- IT assets (software, hardware) for IT system security upgrades, including MAS, ODS and GIS enhancements;
- Metering assets related to new and upgraded customer connections.

Forecast 2014 Bridge Year vs. 2013 Actual

Total forecast gross assets in 2014 of $201,802,983 are an increase of $9,848,639 compared with 2013 Actuals. This is primarily due to the following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to
  - Phase 2 of the overhead plant expansion and rebuilds to allow load transfer from Wilson TS to Thornton TS;
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;
  - The reconstruction of an underground below grade transformer vault and replacements of associated transformers and switches/equipment with modernized intelligent units;
  - MS14 - replacement of underground conduits and 13.8kV lead primary cables and riser poles and distribution lines;
  - New residential and commercial subdivision development and service upgrades;
  - Distribution plant expansion to eliminate Long Term Load Transfer (LTLT) customers with HONI.

- Distribution station assets from the replacement of station power transformer at MS5;
- Underground cables, switchgear and communication equipment and devices related to Phase 1 and 2 of the Distribution UG Vault Automation project involving the replacement of old switches with intelligent, remote operated switches to form an underground self-healing system in downtown Oshawa;
- IT assets (software, hardware) for IT system security upgrades, including MAS, ODS and GIS enhancements;
- Metering assets related to new and upgraded customer connections.

Forecast 2015 Test Year vs. 2014 Bridge Year

Total gross assets in 2015 are forecast to be $217,298,022 or an increase of $15,495,039 compared with 2014 Bridge Year forecast. This is primarily due to following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - OPUCN plant relocation or new infrastructure to facilitate the completion of ECGP's highway 407 construction;
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;
  - New residential and commercial subdivision development or service upgrades.
- Underground cables, switchgear and communication equipment and devices related to Phase 2 and 3 of the Distribution UG Vault Automation project involving the replacement of old switches with intelligent, remote operated switches to form an underground self-healing system in downtown Oshawa;

- Distribution station equipment related to the in service of a new arc flash resistance type 2C switchgear at MS14; and breaker replacement program for the main and bus tie breakers;

- OPUCN capital contributions to HONI to purchase 2 feeder breaker position and address transmission station capacity at Thornton TS over the 5 year period. These contributions are preliminary and will most likely increase subject to the final outcomes of the Regional Planning and Local LDCs planning meetings;

- IT assets (software, hardware) related to installation of Outage Management System (OMS); along with IT system upgrades;

- Metering assets related to new and upgraded customer services connections and OEB's MIST metering requirements;

- Unplanned replacement of a 83ft bucket that reached the end of its useful life in Q2 2014 and will be place in service in 2015.

Forecast 2016 Test Year vs. 2015 Test Year

Total gross assets in 2016 are forecast to be $228,160,647 or an increase of $10,862,624 compared with 2015 Test Tear. This is primarily due to following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - OPUCN plant relocation or new infrastructure to facilitate Phase 2 of ECGP's highway 407 extension;
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;
  - New residential and commercial subdivision development or service upgrades.

- Underground cables, self-healing software and communication network equipment and devices related to Phase 4 of the Distribution UG Vault Automation project involving the replacement of old switches with intelligent, remote operated units;
- Proposed municipal substation building (MS9);

- OPUCN capital contributions to HONI to purchase 2 feeder breaker position and address transmission station capacity at Thornton TS over the 2015 – 2016 year period. These contributions are preliminary and will most likely increase subject to the final outcomes of the Regional Planning and Local LDCs planning meetings;

  - Distribution station equipment related to main and bus tie breaker replacement (13.8kV and 44kV Oil Circuit Breaker);
  - IT assets (software, hardware) – proposed replacement of ODS along with IT system upgrades;
  - Proposed two new vehicles;
  - Metering assets related to new and upgraded customer services connections and OEB's MIST metering requirements.

Forecast 2017 Test Year vs. 2016 Test Year

Total gross assets in 2017 are forecast to be $240,162,538 or an increase of $12,001,891 compared with 2016 Test Year. This is primarily due to following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;

  - Installation of self-healing Intelli-Rupter type switches for overhead grid automation;
  - New residential and commercial subdivision development or service upgrades.
- OPUCN capital contributions to HONI to purchase and own 2 feeder breaker position and address transmission station capacity at both Wilson TS and Thornton TS over the 5 year period. These contributions are preliminary and will most likely increase subject to the final outcomes of the Regional Planning and Local LDCs planning meetings;
- Distribution station equipment related to installation of MS9; including 44kV Oil circuit breaker (4 replacements every year);
- IT assets (software, hardware) – proposed IT system upgrades; self-healing grid software for overhead automated Self-healing Switching – Intelli-Rupters switches (8 feeders 13 switches over 3 years, 2017-2019);
- Purchase of two new vehicles;
- Metering assets related to new and upgraded customer services connections and OEB's MIST metering requirements.

Forecast 2018 Test Year vs. 2017 Test Year

Total gross assets in 2018 are forecast to be $251,618,669 or an increase of $11,456,131 compared with 2017 Test year. This is primarily due to following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;

  - Proposed distribution primary feeders related to proposed MS9 construction;
  - New residential and commercial subdivision development or service upgrades.
- Distribution station equipment related to proposed completion/in service of MS9; including 44kV Oil circuit breaker replacement program (4 replacements at each substation every year (2016-2018);
- OPUCN capital contributions to HONI to purchase 2 feeder breaker position and address transmission station capacity at both Wilson TS and Thornton TS over the 5 year period. These contributions are preliminary and will most likely increase subject to the final outcomes of the Regional Planning and Local LDCs planning meetings;
- IT assets (software, hardware):
  - proposed IT system upgrades;
  - Servers Upgrades in Production and DRP - End of uselife in 2018;
  - self-healing grid software for overhead automated self-healing system using Intelli-Rupters switches (8 feeders 13 switches over 3 years, 2017-2019);
  - Volt-Var optimization & Reduction in Distribution Losses;
  - Distribution System Supply Optimization.
- Purchase of new vehicles;
- Metering assets related to new and upgraded customer services connections and OEB's MIST metering requirements.

Forecast 2019 Test Year vs. 2018 Test Year

Total gross assets in 2019 are forecast to be $261,518,019 or an increase of $9,899,351 compared with 2018 Test year. This is primarily due to following capital additions:

- Underground conduits, cables, transformers, switchgear and devices plus poles, overhead lines/conductors, line transformers and devices related to:
  - The Region of Durham and City of Oshawa road reconstruction;
  - Planned overhead and underground rebuilds, including emergency work, required as part of asset renewal to maintain or improve system reliability;
  - Proposed distribution primary feeders related to proposed MS9 construction;
  - New residential and commercial subdivision development or service upgrades.
- IT assets (software, hardware):
  - proposed IT system upgrades, including MAS, GIS and ODS enhancements;
  - self-healing grid software for overhead automated Self-healing System – Intelli-Rupters switches (8 feeders 13 switches over 3 years, 2017-2019);
  - Volt-Var optimization & Reduction in Distribution Losses;
  - Distribution System Supply Optimization.
- Purchase of new vehicles;
- Metering assets related to new and upgraded customer services connections and OEB's MIST metering requirements.

ACCUMULATED DEPRECIATION – BY FUNCTION

Accumulated Depreciation is divided into two principal categories (distribution plant and general plant) as illustrated in Table 2-26. OPUCN has included the accumulated depreciation associated with asset accounts 1805 to 1860, and 1910 in the category of distribution plant, and accounts 1915 to 1980, and 1611 in the category of general plant in accordance with the Uniform System of Accounts ('USoA"). OPUCN does not have any transmission plant assets. Capital contributions have been listed separately.

TABLE 2-26 - ACCUMULATED DEPRECIATION BY FUNCTION

Description	2011 Actual MIFRS	2012 Board Approved MIFRS	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS
Distribution Plant	78,983,846	82,450,209	81,215,078	81,902,281	82,437,827
General Plant	8,436,714	9,161,919	8,977,814	9,742,521	10,785,376
Capital Contributions	(6,966,724)	(7,045,238)	(7,535,586)	(8,219,274)	(8,801,534)
Other	0	0	0	0	0
Total less Capital Contributions	80,453,836	84,566,889	82,657,305	83,425,527	84,421,669

Description	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Distribution Plant	84,038,787	86,544,299	89,993,666	93,299,174	97,014,091
General Plant	11,947,474	13,209,193	14,399,599	15,512,151	16,531,388
Capital Contributions	(9,602,419)	(10,476,590)	(11,378,287)	(12,304,880)	(13,253,746)
Other	0	0	0	0	0
Total less Capital Contributions	86,383,843	89,276,902	93,014,979	96,506,445	100,291,733

Detailed amounts categorized by major plant account are provided in Tables 2-27 through 2-29 of this Exhibit. Table 2-26 provides a summary of Accumulated Depreciation for the 2012 Board-Approved amounts; 2011, 2012 and 2013 Actual results; forecast 2014 Bridge Year; and 2015 through 2019 Test Years:

TABLE 2-27 - ACCUMULATED DEPRECIATION – DETAILED BREAKDOWN 2011-2012

Description	USA	2011 Actual MIFRS	2012 Actual MIFRS	Variance 2012 Actual Vs 2011 Actual	2012 Board Approved MIFRS	2012 Actual MIFRS	Variance 2012 Actual Vs 2012 Board Approved
Buildings	1808	359,638	373,874	14,236	366,324	373,874	7,550
Leasehold Improvements	1910	205,854	376,469	170,615	308,070	376,469	68,399
Land and Buildings sub-total		**565,493**	**750,343**	**184,851**	**674,394**	**750,343**	**75,949**
Distribution Station Equipment	1820	7,935,939	7,524,214	(411,725)	8,233,305	7,524,214	(709,091)
Distribution Station Equipment sub-total		**7,935,939**	**7,524,214**	**(411,725)**	**8,233,305**	**7,524,214**	**(709,091)**
Poles, Towers & Fixtures	1830	13,619,315	14,023,397	404,082	14,062,664	14,023,397	(39,267)
Overhead Conductors & Devices	1835	9,097,722	9,308,228	210,507	9,491,057	9,308,228	(182,829)
Underground Conductors & Devices	1845	16,483,653	17,158,325	674,673	17,410,293	17,158,325	(251,968)
Poles and Wires sub-total		**39,200,689**	**40,489,951**	**1,289,262**	**40,964,015**	**40,489,951**	**(474,064)**
Line Transformers	1850	28,798,432	29,255,984	457,551	29,388,709	29,255,984	(132,726)
Line Transformers sub-total		**28,798,432**	**29,255,984**	**457,551**	**29,388,709**	**29,255,984**	**(132,726)**
Meters	1860	2,483,293	3,194,586	711,293	3,189,785	3,194,586	4,801
Meters sub-total		**2,483,293**	**3,194,586**	**711,293**	**3,189,785**	**3,194,586**	**4,801**
Computer Equipment - Hardware	1920	2,121,541	2,138,972	17,430	2,183,367	2,138,972	(44,395)
Computer Software	1611	365,879	572,404	206,525	511,506	572,404	60,898
IT Assets sub-total		**2,487,420**	**2,711,376**	**223,955**	**2,694,873**	**2,711,376**	**16,503**
Office Furniture & Equipment	1915	643,906	652,660	8,754	656,571	652,660	(3,912)
Transportation Equipment	1930	2,140,152	2,168,150	27,998	2,386,560	2,168,150	(218,410)
Stores Equipment	1935	24,228	24,516	288	26,634	24,516	(2,118)
Tools, Shop & Garage Equipment	1940	1,489,162	1,706,220	217,059	1,688,555	1,706,220	17,665
Measurement & Testing Equipment	1945	268,607	282,082	13,475	291,404	282,082	(9,323)
Communications Equipment	1955	251,398	264,123	12,724	251,398	264,123	12,724
Miscellaneous Equipment	1960	59,758	79,111	19,353	59,758	79,111	19,353
Load Management Controls - Customer	1970	36,163	36,163	0	36,163	36,163	0
Load Management Controls - Utility	1975	742,337	759,831	17,494	776,420	759,831	(16,589)
System Supervisor Equipment	1980	293,583	293,583	0	293,583	293,583	0
Equipment sub-total		**5,949,294**	**6,266,438**	**317,145**	**6,467,046**	**6,266,438**	**(200,608)**
Accumulated Depreciation Total		**87,420,560**	**90,192,892**	**2,772,332**	**91,612,128**	**90,192,892**	**(1,419,236)**
Contributions & Grants	1995	(6,966,724)	(7,535,586)	(568,862)	(7,045,238)	(7,535,586)	(490,348)
Accumulated Depreciation Less Capital Contributions		80,453,836	82,657,305	2,203,469	84,566,889	82,657,305	(1,909,584)

TABLE 2-28 - ACCUMULATED DEPRECIATION – DETAILED BREAKDOWN 2013-2015

Description	USA	2013 Actual MIFRS	Variance 2013 Actual Vs 2012 Actual	2014 Bridge Year MIFRS	Variance 2014 Bridge Vs 2013 Actual	2015 Test Year MIFRS	Variance 2015 Test Year Vs 2014 Bridge
Buildings	1808	388,071	14,197	402,268	14,197	422,513	20,245
Leasehold Improvements	1910	530,275	153,806	664,126	133,851	835,396	171,269
Land and Buildings sub-total		**918,346**	**168,003**	**1,066,394**	**148,048**	**1,257,909**	**191,514**
Distribution Station Equipment	1820	7,660,747	136,533	7,766,718	105,971	8,143,012	376,294
Distribution Station Equipment sub-total		**7,660,747**	**136,533**	**7,766,718**	**105,971**	**8,143,012**	**376,294**
Poles, Towers & Fixtures	1830	13,807,057	(216,340)	13,034,476	(772,581)	12,565,339	(469,137)
Overhead Conductors & Devices	1835	8,687,050	(621,178)	8,231,009	(456,041)	8,059,700	(171,309)
Underground Conductors & Devices	1845	17,636,228	477,903	17,759,132	122,905	18,029,876	270,744
Poles and Wires sub-total		**40,130,335**	**(359,615)**	**39,024,618**	**(1,105,718)**	**38,654,916**	**(369,702)**
Line Transformers	1850	29,250,700	(5,283)	29,862,654	611,954	30,507,887	645,233
Line Transformers sub-total		**29,250,700**	**(5,283)**	**29,862,654**	**611,954**	**30,507,887**	**645,233**
Meters	1860	3,942,151	747,565	4,717,443	775,291	5,475,063	757,621
Meters sub-total		**3,942,151**	**747,565**	**4,717,443**	**775,291**	**5,475,063**	**757,621**
Computer Equipment - Hardware	1920	2,225,766	86,794	2,354,713	128,947	2,534,895	180,182
Computer Software	1611	939,026	366,622	1,345,240	406,214	1,777,915	432,675
IT Assets sub-total		**3,164,792**	**453,416**	**3,699,953**	**535,161**	**4,312,810**	**612,857**
Office Furniture & Equipment	1915	662,321	9,661	669,761	7,441	679,195	9,434
Transportation Equipment	1930	2,197,729	29,579	2,471,838	274,109	2,765,701	293,863
Stores Equipment	1935	24,516	0	24,516	0	24,516	0
Tools, Shop & Garage Equipment	1940	1,906,363	200,143	2,070,409	164,046	2,212,306	141,897
Measurement & Testing Equipment	1945	296,874	14,792	312,914	16,040	330,332	17,419
Communications Equipment	1955	284,605	20,482	300,459	15,854	316,313	15,854
Miscellaneous Equipment	1960	98,298	19,187	111,054	12,757	123,811	12,757
Load Management Controls - Customer	1970	36,163	0	36,163	0	36,163	0
Load Management Controls - Utility	1975	777,278	17,447	794,725	17,447	852,742	58,017
System Supervisor Equipment	1980	293,583	0	293,583	0	293,583	0
Equipment sub-total		**6,577,729**	**311,291**	**7,085,423**	**507,694**	**7,634,664**	**549,241**
Accumulated Depreciation Total		**91,644,802**	**1,451,910**	**93,223,203**	**1,578,401**	**95,986,261**	**2,763,058**
Contributions & Grants	1995	(8,219,274)	(683,688)	(8,801,534)	(582,259)	(9,602,419)	(800,885)
Accumulated Depreciation Less Capital Contributions		83,425,527	768,222	84,421,669	996,142	86,383,843	1,962,173

TABLE 2-29 - ACCUMULATED DEPRECIATION – DETAILED BREAKDOWN 2016-2019

Description	USA	2016 Test Year MIFRS	Variance 2016 Test Year Vs 2015 Test Year	2017 Test Year MIFRS	Variance 2017 Test Year Vs 2016 Test Year	2018 Test Year MIFRS	Variance 2018 Test Year Vs 2017 Test Year	2019 Test Year MIFRS	Variance 2019 Test Year Vs 2018 Test Year
Buildings	1808	454,607	32,094	494,766	40,158	534,924	40,158	575,082	40,158
Leasehold Improvements	1910	1,006,986	171,591	1,134,149	127,163	1,252,976	118,827	1,378,976	126,000
Land and Buildings sub-total		**1,461,593**	**203,685**	**1,628,915**	**167,322**	**1,787,900**	**158,985**	**1,954,058**	**166,158**
Distribution Station Equipment	1820	8,462,300	319,288	8,908,342	446,042	9,418,553	510,211	9,839,727	421,174
Distribution Station Equipment sub-total		**8,462,300**	**319,288**	**8,908,342**	**446,042**	**9,418,553**	**510,211**	**9,839,727**	**421,174**
Poles, Towers & Fixtures	1830	12,574,158	8,819	13,054,157	479,999	13,314,466	260,309	13,771,303	456,837
Overhead Conductors & Devices	1835	8,102,235	42,535	8,372,844	270,610	8,542,464	169,620	8,823,589	281,126
Underground Conductors & Devices	1845	18,475,264	445,387	18,966,297	491,033	19,555,416	589,120	20,265,909	710,493
Poles and Wires sub-total		**39,151,656**	**496,741**	**40,393,298**	**1,241,641**	**41,412,346**	**1,019,049**	**42,860,802**	**1,448,455**
Line Transformers	1850	31,191,656	683,769	31,926,277	734,621	32,633,123	706,846	33,366,275	733,152
Line Transformers sub-total		**31,191,656**	**683,769**	**31,926,277**	**734,621**	**32,633,123**	**706,846**	**33,366,275**	**733,152**
Meters	1860	6,277,093	802,030	7,136,834	859,741	8,047,252	910,418	8,993,229	945,977
Meters sub-total		**6,277,093**	**802,030**	**7,136,834**	**859,741**	**8,047,252**	**910,418**	**8,993,229**	**945,977**
Computer Equipment - Hardware	1920	2,746,192	211,296	2,944,346	198,155	3,133,981	189,635	3,312,092	178,111
Computer Software	1611	2,280,234	502,319	2,756,333	476,099	3,113,184	356,851	3,345,348	232,164
IT Assets sub-total		**5,026,425**	**713,616**	**5,700,679**	**674,253**	**6,247,165**	**546,486**	**6,657,440**	**410,275**
Office Furniture & Equipment	1915	690,264	11,069	701,651	11,387	713,500	11,848	725,713	12,214
Transportation Equipment	1930	3,089,819	324,118	3,424,884	335,065	3,791,028	366,143	4,175,193	384,165
Stores Equipment	1935	24,516	0	24,516	0	24,516	0	24,516	0
Tools, Shop & Garage Equipment	1940	2,331,693	119,387	2,456,738	125,045	2,585,036	128,298	2,716,245	131,209
Measurement & Testing Equipment	1945	350,437	20,104	372,148	21,711	408,185	36,037	462,626	54,441
Communications Equipment	1955	332,168	15,854	348,022	15,854	365,474	17,452	386,121	20,647
Miscellaneous Equipment	1960	134,885	11,074	141,185	6,299	147,471	6,286	153,758	6,286
Load Management Controls - Customer	1970	36,163	0	36,163	0	36,163	0	36,163	0
Load Management Controls - Utility	1975	899,239	46,497	900,030	790	900,030	0	900,030	0
System Supervisor Equipment	1980	293,583	0	293,583	0	293,583	0	293,583	0
Equipment sub-total		**8,182,768**	**548,103**	**8,698,921**	**516,153**	**9,264,986**	**566,065**	**9,873,948**	**608,962**
Accumulated Depreciation Total		**99,753,492**	**3,767,231**	**104,393,265**	**4,639,773**	**108,811,325**	**4,418,060**	**113,545,479**	**4,734,154**
Contributions & Grants	1995	(10,476,590)	(874,172)	(11,378,287)	(901,696)	(12,304,880)	(926,593)	(13,253,746)	(948,866)
Accumulated Depreciation Less Capital Contributions		89,276,902	2,893,059	93,014,979	3,738,077	96,506,445	3,491,467	100,291,733	3,785,288

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION

The Accumulated Depreciation Variance analysis for the variances identified in Tables 2-27 through 2-29 is provided as follows:

2012 Actual vs. 2011 Actual

The total accumulated depreciation for 2012 was $90,192,892, an increase of $2,772,332 compared with 2011 actuals. This is primarily due to an increase in gross assets of $11,067,787 driven by the renewal of assets (such as line transformers, poles, conductors, cables, station transformers and equipment, meters, fleet, tools, facilities upgrades and equipment, software and hardware and communication equipment) and partially offset by a decrease in accumulated depreciation as assets are disposed of.

2012 Actual vs. 2012 Board-Approved

The total accumulated depreciation for 2012 Actuals was $90,192,892 a decrease of $1,419,236 compared with 2012 Board Approved actuals. This is primarily due to the removal of accumulated depreciation associated with disposed assets along with adjustments related to the transition to MIFRS.

2013 Actual vs. 2012 Actual

The total accumulated depreciation in 2013 was $91,644,802, an increase of $1,451,910 compared with 2012 actuals. This is primarily due to an increase in gross assets of $9,141,562 driven by the renewal of assets (such as line transformers, poles, conductors, cables, station transformers and equipment, meters, fleet, tools, facilities upgrades and equipment, software and hardware and communication equipment) and partially offset by a decrease in accumulated depreciation as assets are disposed of.

Forecast 2014 Bridge Year vs. 2013 Actual

The total accumulated depreciation in 2014 was $93,223,203, an increase of $1,578,401 compared with 2013 actuals. This is primarily due to an increase in gross assets of $9,848,639 driven by the renewal of assets (such as line transformers, poles, conductors, cables, station transformers and equipment, meters, fleet, tools, facilities upgrades and equipment, software and hardware and communication equipment) and partially offset by a decrease in accumulated depreciation as assets are disposed of.

Forecasted 2015 -2019 Test Year vs. 2014 Bridge Year

The forecast accumulated depreciation in 2019 is $113,545,479, an increase of $20,322,276 compared with 2014 Bridge Year actuals. This is driven by depreciation on gross additions of $68,758,638 over the period 2015 to 2019 and partially offset by a decrease of $9,043,602 in accumulated depreciation related to forecast disposals. The change in accumulated depreciation year over year is a direct result of the increased depreciation from capital additions over the five year period partially offset by a decrease in accumulated depreciation as assets are disposed of.

Reconciliation of Continuity Statements to Depreciation Expense

The analysis below provides a summary of the differences in annual depreciation between that shown on the continuity statements and the amounts shown in the trial balance (account 5705) and in Exhibit 4, Table 4-5 Summary of Operating Expenses - Depreciation & Amortization.

	2011	2012	2013	2014 Bridge	2015 Test	2016 Test	2017 Test	2018 Test	2019 Test
	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Accumulated Depreciation Additions per Continuity Schedules - Ch 2 Appendix 2-BA	5,270	3,269	3,852	4,064	4,492	4,847	5,001	5,203	5,371
less: Accrued Smart Meter depreciation expense in 2010 credited to Accrued Expenses, not Accumulated Depreciation	(194)								
OEB Trial Balance - USA 5705 (Revenue Requirement Model)	5,076	3,269	3,852	4,064	4,492	4,847	5,001	5,203	5,371
Accumulated Depreciation Additions per Continuity Schedules - Ch 2 Appendix 2-BA	5,270	3,269	3,852	4,064	4,492	4,847	5,001	5,203	5,371
less: Amortization of PP&E Deferral Account		(237)	(200)	(218)	(595)	0	0	0	0
less: Accrued Smart Meter depreciation expense in 2010 credited to Accrued Expenses, not Accumulated Depreciation	(194)								
Exhibit 4, Table 4-5 Summary of Operating Expenses - Depreciation & Amortization	5,076	3,032	3,652	3,845	3,896	4,847	5,001	5,203	5,371

ALLOWANCE FOR WORKING CAPITAL

Overview

OPUCN filed a Cost of Service Application in 2011 for electricity distribution rates effective January 1, 2012. The Board approved a Working Capital Allowance of 15%, the Board's default at the time, in its decision on the 2012 Application.

As part of the Board's Decision on 2012 rates, OPUCN was directed to file a Lead/Lag Study as part of its next Cost of Service Application.

In response to the Board's Direction, OPUCN engaged Ernst and Young LLP ("E&Y") to provide a Lead/Lag Study based on specific Lead inputs (lead times associated with payments for services) and Lag inputs (lag in the collection of revenues) which included:

Lead Inputs:

- Cost of power
- Payroll and benefits
- OM&A expenses
- Payments in lieu of taxes
- Interest expenses
- Debt retirement charges

Lag Inputs:

- Service lag
- Billing lag
- Collections lag
- Payment processing lag

Payments for expenditures included in the Lead/Lag Study were extracted from OPUCN's accounting system and reviewed to determine the lead time between the invoice/service date and the payment date of each expense.

OPUCN provided the meter reading, customer billing and payment cycles to E&Y for their calculation of the revenue lag. The information included all customer classes.

OPUCN determined its Working Capital Allowance to be 13% based on the results of the Lead/Lag study.

The Lead/Lag Study accompanies this Application as an Appendix of this Exhibit.

OPUCN proposes that 13% is appropriate for purposes of calculating the Working Capital Allowance effective January 1, 2015.

OPUCN has provided its calculations for each of 2012 Board Approved, 2012 Actual, 2013 Actual, 2014 Bridge Year, and the 2015 to 2019 Test Years in the following Table 2-30:

TABLE 2-30 - SUMMARY OF WORKING CAPITAL CALCULATION

Account Description	Board-Approved	Actual		Bridge Year	Test Years at Proposed Rates				
	2012	2012	2013	2014	2015	2016	2017	2018	2019
Cost of Power	97,524,785	96,181,988	102,012,056	112,530,041	120,634,817	122,428,838	123,586,740	124,964,741	125,921,985
Operation Expenses	982,254	1,167,906	919,397	1,025,060	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
Maintenance Expenses	1,409,450	1,094,190	1,313,715	1,311,703	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
Billing and Collecting Expenses	2,433,401	2,398,127	2,462,960	2,594,648	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
Administrative and General Expenses	6,505,765	6,430,919	6,361,731	6,204,724	6,699,898	6,877,527	6,942,612	7,079,635	7,219,041
Taxes Other than Income Taxes	149,350	149,309	152,292	155,338	158,445	161,613	165,007	168,473	172,010
Working Capital	109,005,005	107,422,438	113,222,151	123,821,514	132,780,518	135,043,042	136,473,428	138,074,546	139,105,474

APPENDIX 2-2 LEAD/LAG STUDY

See attached (Exhibit 2, Tab A, Schedule 1).

CAPITAL EXPENDITURES

Included within this exhibit are the following sections, which also includes the Distribution System Plan ("DS Plan") as outlined in Chapter 5:

1. Planning;
2. Required Information;
3. Capitalization Policy;
4. Capitalization of Overhead; and
5. Costs of eligible Investments for Distributors

PLANNING

Oshawa PUC Networks Inc. (OPUCN) owns and operates an electricity distribution network that serves 54,660 customers over 149 square kilometers in the City of Oshawa and the Region of Durham.

OPUCN's Capital Investment Plan is developed to meet and enhance the electricity needs and services of its customers, through the implementation of safe, reliable and cost effective investment solutions.

OPUCN's net capital expenditures have increased from $4.7 million in 2010 to $11.1 million in the 2012 Board-Approved Year, to a forecast $11.7 million in the 2014 Bridge Year. Moving forward in the next 5 year planning period 2015 – 2019, OPUCN average annual capital expenditure is forecast to be $12.1 million.

The increase in capital expenditure from 2010 to 2014 is mainly driven by the replacement or renewal of major critical assets, and more recently in 2013 and 2014, with the onset of load materializing with increased subdivision activity, included expenditures for overhead distribution plant rebuilds and expansion to mitigate station capacity issues and facilitate load transfers between transmission stations, Wilson TS and Thornton TS. OPUCN also started the modernization of its grid in 2013 through the introduction of remote, automated switches that has the intelligence to operate as a "self-healing" system, which will further improve overall restoration time, outage impacts to customers and system reliability.

Going forward in 2015-2019, the key drivers for OPUCN capital investments are the acceleration of customer connections in Oshawa (~ 3% annual); associated increase in residential and commercial load growth (kW) of approximately 3% on average per year; and the continuation of grid modernization to move towards a "smarter grid' that will enhance system resilience and reliability and improve customer value and satisfaction.

OPUCN hereby encloses its DS Plan as a standalone document and filed as part of this Exhibit 2. The DS Plan has been prepared in accordance with Chapter 5 of the Ontario Energy Board's (OEB or Board) *Filing Requirements for Electricity Distribution Rate Applications*, July 17, 2013 revision (Guidelines). This DS Plan consolidates documentation of OPUCN's i) asset management process and ii) capital expenditure plan.

In respect of OPUCN's asset management process, the DS Plan documents the approach that OPUCN uses to collect, tabulate and assess information on physical assets, current and future system operating conditions, business needs and customer feedback, and how this information is used to plan, prioritize and optimize planned capital expenditures.

In respect of OPUCN's capital expenditure plan, the DS Plan sets out and supports OPUCN's proposed expenditures on its distribution system and (non-system) general plant over a 5 year planning period, including both capital investment amounts and asset-related maintenance expenditures (O&M).

The DS Plan illustrates how OPUCN has met the OEB's expectations for electricity distributor planning, as those expectations have been articulated in the Board's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012 (RRFE)[1]. In particular, the DS Plan reflects an optimization of proposed capital investments by controlling, pacing and prioritizing capital

[1] RRFE, pages 1-2.

expenditures in a manner that achieves the RRFE identified objectives and outcomes while managing rate impacts.

OPUCN conducted a recent Asset Condition Assessment on its Major Assets and applied standard asset management principles and methodology to identify, prioritize and subsequently schedule the required replacement of non-performing assets to be proactive in reducing the risk impact of in service failures and mitigate rate impact to its customers.

As this is OPUCN's first DS Plan, there is no information to provide on OPUCN's performance in relation to achievement of the operational or other objectives targeted by investments the costs for which were approved through review and acceptance by the Board of previous consolidated plans. Instead, this DS Plan reviews OPUCN's 5 year investment history, culminating in the 2014 bridge year, and analyzes the impacts of this historical investment program on the current and planned asset management and investment strategy

REQUIRED INFORMATION

OPUCN's capital expenditure summary is provided in Table 2-31 below. This table provides an overall summary of capital expenditures for the past four historical years, the 2014 Bridge Year and the 2015 to 2019 Test Years. Capital expenditures are categorised into one of four investment categories: System Access, System Renewal, System Service and General Plant.

TABLE 2-31 - APPENDIX 2-AB CAPITAL EXPENDITURE SUMMARY

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2010	2011	2012		2013	2014	2015	2016	2017	2018	2019
	Actual	Actual	Plan	Actual	Actual	Bridge[2]					
	$ '000	$ '000	$ '000		$ '000	$ '000	$ '000				
System Access	1,447	8,913	2,609	2,899	4,042	3,867	8,995	4,140	3,550	3,435	3,455
System Renewal	4,637	7,039	7,037	7,162	5,971	5,958	4,883	4,932	4,472	4,761	4,851
System Service	0	0		0	1,903	2,830	2,868	2,830	4,670	4,645	3,050
General Plant	775	1,476	1,500	2,302	530	634	1,675	1,180	755	730	510
TOTAL EXPENDITURE GROSS	6,859	17,428	11,146	12,363	12,446	13,289	18,421	13,082	13,447	13,571	11,866
Less 3rd Party Contributions	(2,173)	(931)	(931)	(1,271)	(1,699)	(1,560)	(4,911)	(1,455)	(1,075)	(1,095)	(1,105)
TOTAL EXPENDITURE NET	4,686	16,497	10,215	11,092	10,747	11,729	13,510	11,627	12,372	12,476	10,761
System O&M	1,576	1,798	2,392	2,262	2,233	2,337	2,634	2,860	2,999	3,015	2,878

Notes to the Table:

1. Historical "previous plan" not required unless a plan has previously been filed, 2012 Plan above is 2012 Board Approved.
2. 2014 bridge year include 9 months of actual data.

Explanatory Notes on Variances in Capital Expenditures Summary

OPUCN has completed Appendix 2-AB in accordance with the Chapter 2 Filing Requirements and Chapter 5 Requirements. Historical prior plan data has not been provided since a DSP has not previously been filed with the Board. OPUCN has provided a summary of Appendix 2-AB by category below.

System Access

System Access investments are comprised of projects outside of OPUCN's control that are required to meet customer service obligations in accordance with the DSC and OPUCN's Conditions of Service.

These projects include customer service requests (e.g. expansions and connections); revenue metering and service obligations (e.g. MIST metering, Ministry's Smart Grid Initiatives such as CDM, Renewable Energy Generation); and third party infrastructure developments or road reconstruction. These investments are typically a high priority, cannot be deferred and must proceed as planned.

Prior to 2012, $2.0 million was typical for annual system access expenditures, with 2011 spend of $8.0 million an exception due mainly to the inclusion of $6.8 million in Smart Meter Implementation costs.

2012 to 2014 saw Oshawa's revitalization programs along with UOIT's increase in student registration and wind turbine installation drive increased growth and development. In 2015, planned gross expenditure of approximately $9 million is mainly due to the plant relocation associated with the proposed highway 407 extension (opening in 2015) and related Region and City Road reconstruction. Going forward Oshawa is projecting higher levels of customer growth with resulting increases of approximately $1.5 million annually compared to historical norms.

System Renewal

System renewal investments comprise the replacement of aging equipment and/or refurbishment of distribution assets.

Historically, typical annual system renewal expenditure was approximately $4 to $5 million. However, in 2011, 2012 and 2013, critical Station assets (power transformers and underground lead primary cable) were at or reaching their end of useful life and needed replacing, resulting in increased spend of approximately $2.5 million respectively in each of those years. In November 2013, transformer T1 at MS 5 was taken out of service due to very poor/critical gas test results and was replaced in May 2014. The switchgear at MS14 is also being replaced in 2014 due to accelerated corrosion that materialized from a 2008 station fire.

For the period 2015 to 2019, system renewal expenditures are projected to revert to historical norms of $4.0 million to $5.0 million.

System Service

Projects in this category are driven by transmission and/or distribution capacity constraints due to load growth along with enhanced system operations and efficiencies (e.g. Distribution Automation, Protection and control upgrades).

Continued growth in Oshawa, resulting from the Highway 407 extension and aggressive City initiatives, is driving requirements for significant system capacity investments at both transmission and distribution levels. The need to modernize the Grid to improve reliability and minimize customer outage impacts is also driving increased expenditures.

Over the 2015-2019 period, Capital contributions to Hydro One for additional transmission capacity are approximately $6.5 million while the new MS9 Municipal Station and related distribution feeders will cost approximately $9.0 million. The balance of approximately $2.5 million will be invested in grid modernization.

General Plant

General plant projects include investments in tools, vehicles, building and information systems technology equipment that are required to support the operation and maintenance of the distribution system.

In 2011 & 2012 the significant variance is due to vehicles that were delivered end of Dec 2011 and vehicles not in service till 2012. In addition, as part of the OMS project, OPUCN realized major data issues needing correction and purchased software solutions for GIS data connectivity accuracy.

CAPITAL EXPENDITURES ON A PROJECT-SPECIFIC BASIS

The following tables and narrative analysis summarize OPUCN's capital expenditures on a project specific basis for: 2010-2013 on an actual basis; the 2014 Bridge Year; and the 2015-2019 Test Years on a forecast basis.

Prior to 2011, OPUCN's net annual capital spend on average ranged between $4.0 million and $5.0 million. Investments focused mainly on third party relocation requests; customer service connections, and overhead and underground plant rebuilds.

From 2011 to 2013, net annual capital spending increased to an average of approximately $10.4 million, excluding smart meter implementation which was accounted for in 2011. The incremental annual increase of approximately $4.6 million relative to the period prior to 2011 was driven by critical system renewal replacements and plant rearrangement for system capacity and load transfer capability, and general plant improvements, as described below:

- Four Station rebuilds including the replacements of eight power transformers; UG & OH 44kV infrastructure replacements; relays and breakers replacements ($7.0 million);
- Four Underground vault rebuilds with associated equipment upgrades ($1.5 million);
- Specifically in 2013, $1.6 million in overhead and underground plant rearrangements to facilitate load transfers and load system balancing, being initial collaborative solutions with Hydro One to address on a preliminary basis the upcoming system capacity issues; and
- General Plant: Fleet, Facilities, GIS, ODS and IT Upgrades – Server room and DRP site ($3.6 million);

Key Drivers for OPUCN's 2014-2019 Capital investment Plan are as follows:

- Customer connections growing by approximately 15% over the 5 year period;
- Residential and commercial average peak demand (kW) growth of approximately 3% annually; and
- Grid modernization to enhance value provided to the customer, including system reliability and resilience. This will involve distribution automation, intelligent devices and software applications to mitigate customer impact of system outages, reduce system restoration time and improve customer satisfaction.

In 2014, OPUCN forecasts net total expenditure of approximately $11.7 million. Highlights of the significant investments include:

System Access ($2.3 million)

- Increase in customer connections and related metering;
- LTLT projects;

System Service ($2.8 million)

- To address load growth in Oshawa and resulting capacity constrains at both Wilson and Thornton transmission stations (TS) -overhead extension and upgrades of primary feeders to allow switching flexibility and system load balancing between Wilson and Thornton TS (~$1.8 million);
- Underground downtown vault automation to enhance system reliability and resiliency (a "smart grid" project) (~$1 million);

System Renewal ($6.0 million)

- replacement of overhead and underground rebuilds including station power transformer replacement (MS5) and replacement of MS14 switchgear;

General Plant ($634 thousand)

OPUCN's total capital expenditure over the planning period (2015 to 2019) is forecast to be approximately $60.8 million, with a net average annual spend of $12.2 million. OPUCN's critical system renewal requirements have stabilized, with future capital expenditures on existing assets focused more on sustainment than renewal. Customer growth, related capacity requirements, and grid modernization are the main drivers for OPUCN's capital spend forecast over the 2015 - 2019 planning period.

A summary of OPUCN's capital projects by year is provided in Table 2-32 - Appendix 2-AA.

TABLE 2-32 - APPENDIX 2-AA CAPITAL PROJECTS ($000S)

Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access										
Subdivision Expansions	918	1,300	1,816	1,820	2,100	1,075	1,125	1,150	1,180	1,215
Service connections/requests	430	366	150	160	110	120	110	100	100	100
Service/Expansion Contributions	(2,034)	(931)	(1,271)	(1,459)	(1,560)	(650)	(675)	(690)	(705)	(730)
Hwy 407 Extension - Plant relocation					430	4,510	700			
Hwy 407 contribution					0	(3,580)	(400)			
Durham Region - Plant relocation	0	447	347	450	250	1,875	935	1,065	1,080	1,055
Durham Region Contribution	(139)	0	0	(150)	0	(506)	(235)	(265)	(280)	(255)
City of Oshawa - Plant relocation	0	20	0	258	302	680	595	470	460	470
City of Oshawa Contribution				(90)	0	(175)	(145)	(120)	(110)	(120)
Metering service connections	99	6,780	586	573	280	375	380	390	390	390
Remote Disconnect/Reconnect Metering						100	100	100	100	100
PrePaid Metering								150		
OEB's MIST Metering					0	150	150	125	125	125
Long Term load transfers (LTLT)				781	395					
MoE approved Micro Grid Project					0	110	45			
System Access Total	(726)	7,982	1,628	2,343	2,307	4,084	2,685	2,475	2,340	2,350
System Renewal										
O/H Rebuilds	2,288	2,215	1,390	2,407	2,663	2,410	2,455	2,055	2,510	2,117
U/G Rebuilds	684	1,416	1,013	1,789	1,450	1,133	1,007	1,087	921	904
Station Rebuilds	466	2,758	3,879	925	1,015	510	640	500	500	1,000
Reactive/emergency Plant Replacement	1,199	650	880	850	830	830	830	830	830	830
System Renewal Total	4,637	7,039	7,162	5,971	5,958	4,883	4,932	4,472	4,761	4,851
System Services										
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension				1,903	1,930					
Thorton TS Capacity - HONI Contributions						1,500	1,500			
Wilson TS Capacity - HONI Contributions								1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation						750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders									1,000	1,000
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements					900	548	280	10	10	10
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)								350	350	255
Smart Fault Indicators						25	25	25	25	25
Volt-Var optimization & Reduction in Distribution Losses					0	0	0	0	225	225
Distribution System Supply Optimization						45	25	35	35	35
System Services Total	0	0	0	1,903	2,830	2,868	2,830	4,670	4,645	3,050
General Plant										
Fleet	245	585	1,438	17	155	420	415	440	190	170
Total Facilities Leasehold Improvements	36	354	174	17	104	225	50	50	50	50
Major Tools and Equipment	152	110	110	44	40	50	50	50	50	50
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	0	0	0	0	75	850	0	0	0	0
Mobile Work force					0		50	50		
ODS Replacement due to enhanced operational requirements not available with existing ODS							400			
GIS Enhancements for operational needs including OMS					120		60	60	60	60
MAS Enhancements for operational needs					25		25	25	50	50
ODS/CIS Enhancements for operational needs					25				50	50
Office IT Capital Expenditure	64	165	167	270	90	130	130	80	280	80
General Plant Total	497	1,214	1,889	348	634	1,675	1,180	755	730	510
Miscellaneous	278	262	413	182						
Total	**4,686**	**16,497**	**11,092**	**10,747**	**11,729**	**13,510**	**11,627**	**12,372**	**12,476**	**10,761**

YEARLY COMPARISON WITH PROJECT SPECIFIC VARIANCE ANALYSIS

2011 Actuals (CGAAP) versus 2010 Actuals (CGAAP)

OPUCN's total actual capital expenditures in 2011 is $16.5 million or $11.8 million more than 2010 total expenditures, as indicated in Table 2-33 below. This is mainly due to the Smart Meter Project implementation being accounted for in 2011, along with a significant increase in system renewal expenditures to replace critical station assets at or reaching end of useful life.

TABLE 2-33 - 2011 ACTUAL VS 2010 ACTUAL CAPITAL PROJECTS ($000S)

Projects	2010 Actual	2011 Actual	Variance 2011 Actual vs 2010 Actual
Reporting Basis	**CGAAP**	**CGAAP**	
System Access			
Subdivision Expansions	918	1,300	382
Service connections/requests	430	366	(64)
Service/Expansion Contributions	(2,034)	(931)	1,103
Durham Region - Plant relocation	0	447	447
Durham Region Contribution	(139)	0	139
City of Oshawa - Plant relocation	0	20	20
Metering service connections	99	6,780	6,681
System Access Total	(726)	7,982	8,708
System Renewal			
O/H Rebuilds	2,288	2,215	(73)
U/G Rebuilds	684	1,416	732
Station Rebuilds	466	2,758	2,292
Reactive/emergency Plant Replacement	1,199	650	(549)
System Renewal Total	4,637	7,039	2,402
System Services Total	0	0	0
General Plant			
Fleet	245	585	340
Total Facilities Leasehold Improvements	36	354	318
Major Tools and Equipment	152	110	(42)
Office IT Capital Expenditure	64	165	101
General Plant Total	497	1,214	717
Miscellaneous	278	262	(16)
Total	**4,686**	**16,497**	**11,811**

2011 System Access

Total System Access expenditures increased in 2011 by $8.7 million compared with 2010 mainly due to smart meter implementation accounted for in 2011 along with an increase in subdivision activity. Projects above the materiality threshold include:

- Metering – OPUCN's expenditures in 2011 was $6.7 million due to smart meter installation program accounted for in 2011;
- Subdivision Expansions – These projects are non-discretionary and are directly related to growth in the City of Oshawa. In 2011, subdivision development expenditure of $1.3 million was an increase of $0.4 million compared with 2010;
- Service connections/requests – Connection requests were higher by $1.0 million. These projects are non-discretionary and driven by customer requests; and
- Durham Region and City of Oshawa road reconstruction. These projects are regionally and municipally driven and are non-discretionary. In 2011, expenditures increased by $0.5 million compared with 2010, mainly due to projects delayed from earlier years.

2011 System Renewal

2011 Total System Renewal expenditures of $7.0 million represents an increase of $2.4 million over 2010, mainly due to major station rebuilds and underground vault reconstruction as follows:

- Station Rebuilds - Replacement of three Station power transformers (2 units at MS11 and 1 unit at MS13) at a cost of $2.3 million;
- UG rebuilds - Reconstruction of the underground below grade vault and replacement of associated vault equipmen, along with UG primary cable replacement at MS11 of $732 thousand; and

- Partially offset by $549 thousand lower than planned emergency spending.

2011 General Plant

2011 Total General Plant expenditures of $1.2 million was an increase of $717 thousand over 2010 due to higher expenditures on facilities, fleet and GIS enhancement as follows:

- Fleet expenditures – primarily new double bucket with increased capacity to replace old 1996 vehicle;
- Renovations to operations building including rewiring to bring up to current standards; and
- Incremental GIS software enhancements of $100 thousand.

2012 Actuals (MIFRS) versus 2011 Actuals (CGAAP)

OPUCN's total capital expenditures in 2012 is $5.4 million lower than 2011 total expenditures as indicated in Table 2-34 below. This is mainly due to smart meters accounted for in 2011 partially offset by higher fleet expenditures in 2012.

TABLE 2-34 - 2012 ACTUAL VS 2011 ACTUAL CAPITAL PROJECTS ($000S)

Projects	2011 Actual	2012 Actual	Variance 2012 Actual vs 2011 Actual
Reporting Basis	**CGAAP**	**MIFRS**	
System Access			
Subdivision Expansions	1,300	1,816	516
Service connections/requests	366	150	(216)
Service/Expansion Contributions	(931)	(1,271)	(340)
Durham Region - Plant relocation	447	347	(100)
City of Oshawa - Plant relocation	20	0	(20)
Metering service connections	6,780	586	(6,194)
System Access Total	7,982	1,628	(6,354)
System Renewal			
O/H Rebuilds	2,215	1,390	(825)
U/G Rebuilds	1,416	1,013	(403)
Station Rebuilds	2,758	3,879	1,121
Reactive/emergency Plant Replacement	650	880	230
System Renewal Total	7,039	7,162	123
System Services Total	0	0	0
General Plant			
Fleet	585	1,438	853
Total Facilities Leasehold Improvements	354	174	(180)
Major Tools and Equipment	110	110	0
Office IT Capital Expenditure	165	167	2
General Plant Total	1,214	1,889	675
Miscellaneous	262	413	151
Total	**16,497**	**11,092**	**(5,405)**

2012 System Access

Total System Access expenditures decreased in 2012 by $6.4 million compared with 2011 due to smart meter implementation accounted for in 2011 along with more customer contributions received than planned:

- Metering – OPUCN's expenditures was $0.6 million or $6.2 million lower than 2011 expenditures mainly due to smart meter installation program accounted for in 2011;
- Subdivision Expansions – These projects are non-discretionary and are directly related to growth in the City of Oshawa. Subdivision development activity increased, resulting in $0.5 million or $0.2 million net after capital contributions, higher than 2011. ;
- Service connections/request – Connection requests in 2012 were $216 thousand lower than 2011. These projects are non-discretionary and driven by customer requests; and
- Durham Region and City of Oshawa road reconstruction – 2012 actual expenditures of $347 thousand were $120 thousand less than 2011 due to work schedule delays with some projects not 100% completed and carried over to 2013. These projects are regionally and municipally driven and are non-discretionary.

<u>2012 System Renewal</u>

Total System Renewal expenditures increased slightly in 2012 to $7.2 million from $7.0 million in 2011 mainly due to major additional station rebuilds and higher than anticipated emergency work, partially offset by fewer than planned overhead and underground rebuild projects. Project specifics as follows:

- Station Rebuilds - Replacement of four Station power transformers (2 units at MS15 and 2 units at MS2) with at a cost of $3.2 million or $1.1 million higher than transformer replacements and associated work in 2011;
- Overhead rebuilds –2012 expenditures of $1.4 million or $825 thousand lower than 2011, were in line with plan which projected fewer overhead projects for 2012;

- UG rebuilds – 2012 expenditures of $1.0 million or $403 thousand lower than 2011, were in line with plan which projected fewer underground projects for 2012; and
  - Higher than anticipated emergency work in 2012 compared to 2011 causing an increase of $230 thousand.

2012 General Plant

Total General Plant expenditures increase of $675 thousand over 2011 is mainly due to additional vehicle expenditures, partially offset by lower than planned Facilities expenditures.

- Fleet - Two vehicles (digger derrick and substation cube van) were delivered in December 2011 and placed in service in 2012, along with unplanned fleet expenditures resulting in $853 thousand accounted for in 2012; and
- Facilities/Leasehold improvements – Decrease of $180 thousand primarily due to operations building renovations completed in 2011.

2012 Actuals (MIFRS) versus 2012 Board Approved (MIFRS)

OPUCN's total actual capital expenditures in 2012 is $871 thousand higher than 2012 Board Approved Plan total expenditures as indicated in Table 2-35 below. This is mainly due to additional General Plant expenditures along with higher than expected emergency type replacements partially offset by higher than anticipated customer contributions and delayed completion of LTLT and plant relocation.

TABLE 2-35 - 2012 ACTUAL VS 2012 BOARD APPROVED CAPITAL PROJECTS ($000S)

Projects	2012 Board Approved	2012 Actual	Variance 2012 Actual vs 2012 Board Approved
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,104	1,816	712
Service connections/requests	175	150	(25)
Service/Expansion Contributions	(925)	(1,271)	(346)
Durham Region - Plant relocation	600	347	(253)
City of Oshawa - Plant relocation	0	0	0
LTLT	280	0	(280)
Metering service connections	450	586	136
System Access Total	1,684	1,628	(56)
System Renewal			
O/H Rebuilds	1,307	1,390	83
U/G Rebuilds	1,062	1,013	(49)
Station Rebuilds	3,900	3,879	(21)
Reactive/emergency Plant Replacement	768	880	112
System Renewal Total	7,037	7,162	125
System Services Total	0	0	0
General Plant			
Fleet	1,020	1,438	418
Total Facilities Leasehold Improvements	130	174	44
Major Tools and Equipment	50	110	60
Office IT Capital Expenditure	300	167	(133)
General Plant Total	1,500	1,889	389
Miscellaneous	0	413	413
Total	**10,221**	**11,092**	**871**

2012 System Access

2012 Total System Access expenditures is $56 thousand lower than Board Approved expenditures mainly due to higher than expected expenditures related to increase subdivision, service connections and associated metering, offset by higher than expected receipt of customer contributions and delayed completion of Durham Region plant relocation and LTLT projects.

- Subdivision Expansions – These projects are non-discretionary and are directly related to growth in the City of Oshawa. Subdivision development activity increased, resulting in approximately $340 thousand net of contributions.
- Durham Region road reconstruction – These projects are regionally driven and are non-discretionary. 2012 actual expenditures of $347 thousand were $253 thousand less than Board Approved 2012 due to Region delays on some projects causing non completion and work being carried over to 2013.
- LTLT projects – 2012 Board Approved expenditures of $280 thousand did not materialize as these projects involved joint use pole agreements with HONI who had delays in their pole replacements. This caused projects to be incomplete and carried over to 2013.
- Metering – 2012 actuals of $586 thousand is $136 thousand higher than Board Approved due to higher than expected service connections.

2012 System Renewal

2012 Total System Renewal expenditures of $7.162 million is $125 thousand higher than Board Approved expenditures mainly due to higher than anticipated emergency work.

2012 General Plant

2012 Total General Plant expenditures of $1.889 million is $389 thousand higher than Board Approved expenditure mainly due to additional vehicle expenditures, unplanned equipment and partially offset by lower Office IT systems in service expenditures.

- Fleet - Two vehicles (digger derrick and substation cube van) were delivered in December 2011 and placed in service in 2012 (~$417 thousand);
- Tools and equipment – Unplanned installation of security cameras in station (~$60 thousand);
- Office IT systems – Decrease of $133 thousand primarily due to in service delays.

2013 Actuals (MIFRS) versus 2012 Actuals (MIFRS)

OPUCN's total capital expenditures in 2013 of $10.7 million was $345 thousand lower than 2012 total expenditures as indicated in Table 2-36 2013 below. This is mainly due to overhead plant expansion expenditures of $1.9 million to enable flexibility in load transfers and address station capacity issues, along with Long Term Load Transfer (LTLT) projects of $781, partially offset by decreases in system renewal expenditures of $1.2 million and fleet expenditures of $1.4 million.

TABLE 2-36 - 2013 ACTUAL VS 2012 ACTUAL CAPITAL PROJECTS ($000S)

Projects	2012 Actual	2013 Actual	Variance 2013 Actual vs 2012 Actual
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,816	1,820	4
Service connections/requests	150	160	10
Service/Expansion Contributions	(1,271)	(1,459)	(188)
Durham Region - Plant relocation	347	450	103
Durham Region Contribution	0	(150)	(150)
City of Oshawa - Plant relocation	0	258	258
City of Oshawa Contribution		(90)	(90)
Metering service connections	586	573	(13)
Long Term load transfers (LTLT)		781	781
MoE approved Micro Grid Project			0
System Access Total	1,628	2,343	715
System Renewal			
O/H Rebuilds	1,390	2,407	1,017
U/G Rebuilds	1,013	1,789	776
Station Rebuilds	3,879	925	(2,954)
Reactive/emergency Plant Replacement	880	850	(30)
System Renewal Total	7,162	5,971	(1,191)
System Services			
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension		1,903	1,903
System Services Total	0	1,903	1,903
General Plant			
Fleet	1,438	17	(1,421)
Total Facilities Leasehold Improvements	174	17	(157)
Major Tools and Equipment	110	44	(66)
Office IT Capital Expenditure	167	270	103
General Plant Total	1,889	348	(1,541)
Miscellaneous	413	182	(231)
Total	**11,092**	**10,747**	**(345)**

2013 System Access

Total 2013 System Access expenditures increased by $715 thousand to $2.3 million mainly due to LTLT expenditures of $781 thousand.

In accordance with the OEB mandate to eliminate all LTLT customers by 2014, OPUCN undertook the completion of these projects, starting in 2013, with the remaining two projects scheduled for completion in 2014. To minimize costs and improve the appearance of the road, OPUCN chose a joint use pole construction with Hydro One and or Bell Canada. The service of these customers by OPUCN distribution system will be of benefit to the affected customers as they will be billed on reduced rates (as OPUCN rates are lower than HONI) and outage restoration efforts will be improved as it will be completed by OPUCN as opposed to HONI. The projects are as follows:

- LTLT - Coates Rd West- Simcoe to Stevenson – mainly underground infrastructure due to trees – actual $324 thousand;
- LTLT - Coates Rd East - 28 HONI poles to be replaced for Joint use – actual $215 thousand;
- LTLT - Townline Rd N Lower - Sale of HONI assets to OPUCN with OPUCN to replace pole line (24 poles) – Actual $242 thousand.

2013 System Renewal

Total System Renewal expenditures in 2013 of $6.0 million is $1.2 million lower than 2012 and is mainly due to fewer station rebuilds planned compared to 2012, partially offset by higher planned overhead and underground rebuilds. Project specifics as follows:

- Station Rebuilds - Actual 2013 expenditure is $925 thousand. Replacement of one Station power transformer at MS 13 at cost of $796 thousand along with station breaker replacement program costs of $129 thousand resulting in a decrease of $2.9 million when compared with 2012 expenditures;

- Overhead rebuilds - Actual 2013 expenditure of $2.4 million is an increase of $1.0 million compared to 2012. Projects over materiality threshold include:

  - Rebuild Phillip Murray Park Rd S to Cedar plus Oxford from Dwight Lakeview. Actual 2013 cost $437 thousand - system reliability, aged plant over 35yrs old cross arm construction - 3 phase 13.8kv 725m 16 poles, 6 transformers, main line 13F4/Oxford 12 poles and 600m, 3 transformers;

  - Rebuild Simcoe St N Rossland to William - Actual 2013 cost $775 thousand - Reliability - Aged plant, deteriorated concrete poles rebar and collar base >35 yrs Potential safety - Replace 50 concrete >35yrs poles with wood poles, 2000m 1 cct 13.8 kV 2 dips 7 transformers;

  - Keewatin St S, Denise Dr. Karen Crt – Actual 2013 costs $162 thousand - Aged Plant over 35 yrs old, #6 Cu primary, open wire secondary, Low service wire issues, Legacy standard installation (OH transformer below secondaries & Street lights above primary) - Replace OH Plant - 14 poles and associated equipment;

  - Olive Ave – Actual 2013 costs $164 thousand Aged plant over 35 yrs old, #6 Cu primary, open wire secondary, Low service wire issue, legacy standard installation (OH transformer below secondaries & street lights above primary) - Replaced 17 poles and associated equipment;

  - Porcelain switches replacement program (2013-2014) – Actual 2013 costs $175 thousand - as supported by METSCO's Asset Condition Assessment Report, these porcelain switches have manufacturer defects and in mid-2011 started to have frequent failure while in service, such that system reliability had negative impacts in 2011 and 2012. OPUCN implemented a systematic two year program (2013 – 2014) to replace these units with polymer type;

- Porcelain insulators replacement program (2013 – 2014) - Actual 2013 costs $241 thousand - as supported by METSCO's Asset Condition Assessment Report, these porcelain switches have manufacturer defects and in mid-2011 started to have frequent failure while in service, such that system reliability had negative impacts in 2011 and 2012. OPUCN implemented a systematic two year program (2013 – 2014) to replace these units with polymer type; and
- Miscellaneous overhead rebuild projects under the Material threshold account for the balance of approximately $400 thousand.

- Underground rebuilds - Actual 2013 expenditure of $1.8 million is an increase of $776 thousand compared to 2012 expenditures, due to additional UG downtown vault rebuild. Projects over the materiality threshold include:
  - 'Regent Theatre Downtown UG Vault Repair (King St East) – Actual 2013 costs $375 thousand - Biddle Structural Engineering Report - vault not structurally sound. Vault to be rebuilt and VacPAk Switches replaced with remote operated switches - potential safety issues;
  - 17 Athol - Downtown UG below Grade Vault – Actual 2013 costs $345 thousand - Biddle Structural Engineering Report - vault not structurally sound. Vault to be rebuilt and VacPAk Switches replaced with remote operated switches - potential safety issues;
  - MS13 UG infrastructure replacements – Actual 2013 costs $625 thousand – underground conduits and 13.8kV/44kV primary cable replacements; and
  - Miscellaneous underground rebuild projects under the Material threshold account for the balance of approximately $455 thousand.

<u>2013 System Service</u>

Total System Service expenditures in 2013 of $1.9 million is an increase of $1.9 million compared with 2012. This is due to the overhead plant expansion to facilitate load transfers between transmission stations and to address the onset of load growth materializing in the North of Oshawa, along with implementation of some distribution automation to enhance system reliability. Projects above the materiality threshold include:

- 15F1 Extension - Harmony Rd, from Coldstream Dr to Conlin Rd East; Conlin Rd East to Townline – Actual 2013 costs $335 thousand – overhead rebuild and expansion require to facilitate load transfers and address station loading issues due to the onset of load materializing;
- Thornton TS - System Capacity – Actual 2013 costs $1.3 million - overhead rebuild and expansion require to facilitate load transfers and address station loading issues due to the onset of load materializing north of Oshawa; and
- Installation of Auto Re-closures switches (distribution automation) - 5 locations – Actual 2013 costs $210 thousand – Required to facilitate automatic re-closure, reduce outage impacts and improve overall reliability.

2013 General Plant

Total General Plant expenditures in 2013 of $348 thousand is a decrease of $1.5 million from 2012, primarily due to lower fleet and facilities expenditures partially offset by IT system and facility security upgrades. Projects above materiality threshold include:

- IT security system upgrades ($116K) – unplanned project required to close gaps in system security, reinforce security access into corporate systems and improve controls, along with installation of electronic fobs and remote security system to better manage facility security and access; and
- Other projects including MAS/ODS enhancements, SANS upgrade and miscellaneous hardware and software make up the balance.

2014 Bridge Year Forecast (MIFRS) versus 2013 Actuals (MIFRS)

As indicated in Table 2-37 2014, OPUCN's forecast total capital expenditure in the Bridge Year 2014 is $11.7 million or $982 thousand higher than 2013 total expenditures.

This increase is mainly due to additional system service expenditures of $900 thousand in grid modernization and an increase in general plant expenditures.

TABLE 2-37 - 2014 BRIDGE YEAR VS 2013 ACTUAL CAPITAL PROJECTS ($000S)

Projects	2013 Actual	2014 Bridge Year	Variance 2014 Bridge Year vs 2013 Actual
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,820	2,100	280
Service connections/requests	160	110	(50)
Service/Expansion Contributions	(1,459)	(1,560)	(101)
Hwy 407 Extension - Plant relocation		430	430
Durham Region - Plant relocation	450	250	(200)
Durham Region Contribution	(150)	0	150
City of Oshawa - Plant relocation	258	302	44
City of Oshawa Contribution	(90)	0	90
Metering service connections	573	280	(293)
Long Term load transfers (LTLT)	781	395	(386)
System Access Total	2,343	2,307	(36)
System Renewal			
O/H Rebuilds	2,407	2,663	256
U/G Rebuilds	1,789	1,450	(339)
Station Rebuilds	925	1,015	90
Reactive/emergency Plant Replacement	850	830	(20)
System Renewal Total	5,971	5,958	(13)
System Services			
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension	1,903	1,930	27
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements		900	900
System Services Total	1,903	2,830	927
General Plant			
Fleet	17	155	138
Total Facilities Leasehold Improvements	17	104	87
Major Tools and Equipment	44	40	(4)
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	0	75	75
GIS Enhancements for operational needs including OMS		120	120
MAS Enhancements for operational needs		25	25
ODS/CIS Enhancements for operational needs		25	25
Office IT Capital Expenditure	270	90	(180)
General Plant Total	348	634	286
Miscellaneous	182		(182)
Total	**10,747**	**11,729**	**982**

2014 System Access

Total 2014 System Access expenditures is forecast to be $2.3 million similar to 2013 Actuals of $2.3 million. Projects above the materiality threshold include:

- Subdivision Expansions – Forecasted gross expenditure are $2.1 million with forecasted developer contributions of $1.6 million. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Although subdivision development activity has started to materialize, OPUCN has chosen to project a reasonable expenditure consistent with current trend. Details and justification of these projects are described in the DS Plan attached as a standalone document. Historically customer contribution covers approximately 60% of the total cost with 40% being the net capital cost to OPUCN;
- Service connections/request – Connection requests are forecast to be $110 thousand in the Bridge Year, approximately $50 thousand less than 2013. These projects are non-discretionary and driven by customer requests, and OPUCN choose to apply a reasonable forecast based on trend. Justification of projects are described in the DS Plan filed as a standalone document within this Exhibit;
- Eastern Construction General Partners (ECGP) Highway 407 Extension (2014 – 2016). Total 2014 Forecast $430 thousand. This project commenced in Q2 2013 with OPUCN tasked with producing design options in 2013 for approval with commencement of Phase 1 construction in 2014. This Highway is scheduled to open in December 2015, with a potential Phase 2 start in 2016. The project has a forecasted total gross expenditure of $5.2 million or $1.2 million net expenditures after expected ECGP's contributions of $4.0 million. ECGP delays resulted in late construction start dates in 2014 such that the majority of work will now be completed in 2015 with the associated remaining expenditures forecasted in 2015. Please see attached DS Plan for details and justification of Project;

- Durham Region and City of Oshawa road reconstruction – In 2014, Total actual net forecast expenditures are $552 thousand. These projects are regionally and municipally driven and are non-discretionary. Due to initiatives set by the Durham Region and the City of Oshawa for road widening, road realignment, sidewalk construction, sewer and water installation and repairs, OPUCN is required to relocate its pole lines and associated plant. As per the Public Service Works on Highways Act, the Region and City of Oshawa contribute 50% of labour and vehicle costs incurred to relocate poles and associated plant. The following projects are over the materiality threshold:
  - Region Relocate Simcoe St North & Conlin Intersection -net $150 thousand – Approx. 8 -10 new 70ft poles, 44kV and 13.8kV 3 phase primary;
  - Region Relocate – Winchester/Harmony Intersection – net $100K- Approx. 18 poles with 810 meters, 13.8 kV, 3 phase lines;
  - Miscellaneous City of Oshawa's relocation projects are below the material threshold and forecast a total net $302 thousand.
- LTLT Projects - In accordance with the OEB mandate to eliminate all LTLT customers by 2014, OPUCN undertook the completion of these projects starting in 2013, with the remaining two projects scheduled for completion in 2014. To minimize costs and improve the appearance of the road allowance, OPUCN chose a joint use pole construction with Hydro One and or Bell Canada. The service of these customers by OPUCN distribution system will be of benefit to the affected customers as they will be billed on reduced rates (as OPUCN rates are lower than HONI) and outage restoration efforts will be improved as it will be completed by OPUCN as opposed to HONI. The following are the remaining LTLT projects to be completed:
  - LTLT – Townline Rd North (Upper) -then up to Howden (LTLT) - $165 thousand - Joint Use with Hydro One poles (37 poles, 2,100m);

- LTLT - Townline Rd North (Middle) - Columbus to Townline, then Townline N of Columbus - $230 thousand - Joint Use with Hydro One poles (9 poles, 480m) and Bell (approx 15 poles, 720m).

2014 System Renewal

Total System Renewal expenditures in the Bridge Year 2014 are forecast to be $6.0 million similar to 2013 Actuals. Justification for these projects are more fully described in the attached DS Plan but essentially they are guided by outcomes of METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

- Overhead Rebuilds: Total $2.7 million
  - Wilson - Wentworth To Bloor: $535 thousand
  - Adelaide St E - Wilson to Harmony: $400 thousand
  - Olive Ave: $120 thousand
  - Porcelain switch replacement Program (replacement program started 2013): $150 thousand
  - Porcelain insulator replacement Program (replacement program started 2013): $200 thousand
  - Simcoe St N Rossland to William: $280 thousand
  - Wilson TS - HONI's ROW - Rear Lot 44 KV distribution Plant Upgrade: $350 thousand Project carried over from 2013 to 2014 due to Customer issues
- Underground Rebuilds: Total $1.5 million
  - 100 Rideau and Anderson Ave Subdivision- UG Cable Replacement: $204 thousand

- Rebuild Londonderry Stm Castlebar Cres, Kilkenny Ct, Cavan Ct, Arklow Ave) $120K
- MS 14 – 6 -13.8kV Feeders lead cable replacement (pot heads leaking) including rebuild UG ducts within stations yard: $500 thousand
- 7 William St - Downtown UG Below Grade Vault: Estimated Total $400 thousand

• Station Rebuilds - Forecasted total expenditures of $1 million or $95 thousand higher than 2013 actual expenditures. Projects over the materiality threshold include:
  - MS5 T1 Power transformer Replacement: Total $840 thousand
  - Substation Breaker Replacement Program: This is a continuation of OPUCN's 13.8kV Breaker replacement Program. Over the 3 year (2014 - 2016) period, the estimated total expenditure is $525 thousand. Annual level of expenditures are reflected in the Table below: For 2014 Forecast expenditure is $175 thousand

		2014 NET	2015 NET	2016 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**
Substation Breaker Replacement Program (2011-2016)	Replace Main Vacuum Breakers with SF6 FPE DST2 Main and Westinghouse bus tie - Replace legacy installations with Improve technology	**$175**	**$210**	**$140**

• Reactive or Emergency Capital Replacements - Total over 5 years (2014 – 2019) is forecast to be $4.2 million or $830 thousand annually. This investment category is forecast based on historic performance and trend, and covers emergency capital replacement of failed assets that are in service or assets that are damaged due to external factors or conditions (e.g. motor vehicle accidents, storms etc.). These capital replacements are nondiscretionary. The following are project categories over the materiality threshold:

- Annual Unplanned Distribution UG Transformer Replacements: Forecast Annual expenditure $220 thousand based on historic trend. OPUCN generally employs a “run-to-failure” strategy for distribution transformers. Underground vault type and or pad mounted type transformers are visually inspected and normally left in service until failure (approximately greater than 40 years). Projects in this category are caused by system incidents under emergency or reactive work and hence are non-discretionary.
- Annual Unplanned UG Secondary Cable Replacements: Forecast Annual expenditure $180 thousand based on historic trend. These projects are unplanned and are non-discretionary as they are driven by emergency failures or reactive type work. Normally driven by contractor damaging cable or cable failure due to age, site conditions, poor insulation etc.
- Annual Unplanned Distribution OH/UG component change out. Forecast annual expenditure of $110 thousand based on historic trend. These projects are unplanned and are non-discretionary as they are driven by emergency failures or reactive type work. Assets normally include switches, insulators, arrestors etc.

2014 System Service

Total System Service expenditures forecast in the Bridge Year 2014 are $2.8 million or an increase of $927 thousand compared with 2013 Actuals. This is mainly due to the added expenditures from the Underground Distribution Automation Projects of $900 thousand. Projects include:

- Wilson TS to Thornton TS Load Transfer (Phase 1) - Gibb St - Stevenson Rd to MS14. Total $1.4 million
- Thornton TS - System Capacity - Turn key Design and Build. Total $362 thousand

- Wilson TS to Thornton TS Load Transfer (Phase 2) to provide station capacity at Wilson TS Total $140 thousand
- Grid Modernization - UG Distribution Automation Project - Phase 1 - Downtown Vaults Automation (including Bell Vault) from 2013. Total $400 thousand
- Grid Modernization - UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (Avanti, Carriage House, Michael Starr, CIBC, PHI Office, William Vaults) Total $500 thousand

2014 General Plant

Total General Plant expenditures forecast in Bridge Year 2014 are $634 thousand or an increase of $286 thousand compared with 2013 Actuals. This is due to additional expenses for fleet, facilities, OMS/GIS upgrades partially offset by lower Office IT. Projects above material threshold include:

- Outage Management System (OMS fully integrated with SCADA, GIS, AMI, CIS, IVR) (2014 - 2015); along with related MAS/GIS/CIS upgrades - 2014 Forecast $245 thousand
- Fleet – $155 thousand
- Facilities/Leasehold improvements – Forecast $104 thousand- roof replacements at stations and warehouse.

2015 Test Year Forecast (MIFRS) versus 2014 Bridge Year Forecasts (MIFRS)

As indicated in Table 2-38, OPUCN’s forecast total capital expenditure in the Test Year 2015 is $13.5 million or $1.8 million higher than 2014 Bridge Year. This increase is mainly due to OPUCN plant relocation driven by the Highway 407 Extension, Region of Durham and City of Oshawa road reconstruction projects, additional mandated metering requirements, and the proposed in service of an Outage Management System (OMS), partially offset by lower system renewal expenditures.

TABLE 2-38 - 2015 TEST YEAR VS 2014 BRIDGE YEAR CAPITAL PROJECTS ($000S)

Projects	2014 Bridge Year	2015 Test Year	Variance 2015 Test Year vs 2014 Bridge Year
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	2,100	1,075	(1,025)
Service connections/requests	110	120	10
Service/Expansion Contributions	(1,560)	(650)	910
Hwy 407 Extension - Plant relocation	430	4,510	4,080
Hwy 407 contribution	0	(3,580)	(3,580)
Durham Region - Plant relocation	250	1,875	1,625
Durham Region Contribution	0	(506)	(506)
City of Oshawa - Plant relocation	302	680	378
City of Oshawa Contribution	0	(175)	(175)
Metering service connections	280	375	95
Remote Disconnect/Reconnect Metering		100	100
OEB's MIST Metering	0	150	150
Long Term load transfers (LTLT)	395		(395)
MoE approved Micro Grid Project	0	110	110
System Access Total	2,307	4,084	1,777
System Renewal			
O/H Rebuilds	2,663	2,410	(253)
U/G Rebuilds	1,450	1,133	(317)
Station Rebuilds	1,015	510	(505)
Reactive/emergency Plant Replacement	830	830	0
System Renewal Total	5,958	4,883	(1,075)
System Services			
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension	1,930		(1,930)
Thorton TS Capacity - HONI Contributions		1,500	1,500
Wilson TS Capacity - HONI Contributions			0
MS9 - 44kV/13.8kV Substation		750	750
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	900	548	(352)
Smart Fault Indicators		25	25
Volt-Var optimization & Reduction in Distribution Losses	0	0	0
Distribution System Supply Optimization		45	45
System Services Total	2,830	2,868	38
General Plant			
Fleet	155	420	265
Total Facilities Leasehold Improvements	104	225	121
Major Tools and Equipment	40	50	10
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	75	850	775
GIS Enhancements for operational needs including OMS	120		(120)
MAS Enhancements for operational needs	25		(25)
ODS/CIS Enhancements for operational needs	25		(25)
Office IT Capital Expenditure	90	130	40
General Plant Total	634	1,675	1,041
Miscellaneous			0
Total	**11,729**	**13,510**	**1,781**

<u>2015 System Access</u>

Total 2015 System Access expenditures is forecast to be $4.1 million or $1.8 million higher than the 2014 Bridge Year forecast, mainly due to forecast expenditures related to the Highway 407 extension and additional metering requirements. Project details are as follows:

- Subdivision Expansions – 2015 forecasted gross expenditure are $1.1 million with forecasted contribution of $650 thousand. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Although subdivision development activity is showing signs of acceleration, OPUCN has chosen to project a reasonable expenditure consistent with current trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Service connection requests – 2015 Connection requests are forecasted to be $120 thousand approximately $10 thousand more than 2014 Bridge Year. These service projects are non-discretionary and driven by customer requests, and OPUCN chose to apply a reasonable forecast expenditure based on trend. Details and justification of these projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached.
- Eastern Construction General Partners (ECGP) Highway 407 Extension (2014-2016) – Total 2015 gross forecast is $4.5 million or net $930 after contributions of $3.6 million. This project had an accelerated start in Q2 2013 whereby OPUCN was required to produced design options in 2013 for ECGP's approval and commencement of Phase 1 construction in 2014. This Highway is scheduled to open in December 2015, with a potential Phase 2 start in 2016. The project has a forecasted Total gross expenditure of $5.2 million or $1.2 million net expenditures after expected ECGP's contributions of $4 million. ECGP delays resulted in late construction start dates in 2014 such that the

majority of work will now be completed in 2015 with the associated remaining expenditures forecasted in 2015. Please see attached DS Plan for details and justification of Project.

- Durham Region and City of Oshawa road reconstruction – In 2015, Total actual expenditures are forecast to be $2.6 million with a net total expenditure of $1.9 million after total contributions of $681 thousand. These projects are regionally and municipally driven and are non-discretionary. Details and justification of these projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached. The following projects are over the material threshold:
  - Region Relocate - Winchester/Harmony Intersection: Net estimated forecast $200 thousand
  - Region Relocate - Harmony Rd N - Coldstream to Taunton Rd N: Net estimated forecast $480 thousand
  - Region Relocate - Harmony Rd N - Rossland to Taunton Rd N: Net estimated forecast $654 thousand
  - City Relocate - Conlin Rd & Stevenson Rd Intersection; Net OPUCN estimated forecast $105 thousand
  - City Relocate - Conlin Rd - East of Stevenson Rd to Founders: Net OPUCN estimated forecast $50 thousand
  - Riverside Dr South - Hoskin Ave to Palace St: NET OPUCN forecast $80 thousand
  - Miscellaneous City of Oshawa's relocation projects are below the material threshold and forecast a Net OPUCN expenditure total $170 thousand
- Metering – The 2015 to 2019 forecast is summarized in the table below. Details and justification of these projects are described in the attached DS Plan filed as a standalone document, but are also summarized below:

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access					
Metering service connections	375	380	390	390	390
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125

- 2015 - 2019 Metering Service Connections: Total forecasted expenditure over 5 years is $1.9 million or an annual average expenditure of $380 thousand. This project includes metering requirements based on the forecasted new and upgraded service connections over the 5 year period. Due to the Hwy 407 extension, it is anticipated that the number of residential, commercial and interval meter installations will increase over the 5 year planning period. Also included in this project category is (i) the unplanned replacement defective metering equipment that are no longer covered by the meter manufacturer warranty; and (ii) the replacement of meters that need to be verified and resealed to comply with Measurement Canada.

- 2015 – 2019 Remote Disconnect and Reconnect Metering Project: Total forecasted expenditure over the 5 years is $500 thousand or an annual average expenditure of $100 thousand. To help minimize operational costs resulting from bad debt and non-payment billing issues, OPUCN plans to implement smart meters with built in disconnect and reconnects that will be controllable by OPUCN's CIS billing system and the collections department.

- 2015 – 2019 OEB's MIST meter mandated requirement for any existing or new installation that has a monthly average peak demand during a calendar year of over 50 kW - Total forecasted expenditure over the 5 years is $675 thousand or an annual average expenditure of approximately $135 thousand. As part of the OEB Mandate, which came into force on August 21, 2014, utilities are now expected by 2020, to upgrade all of General Services customers >50KW currently not interval metered, including any new installations. In Oshawa, there are approximately 500 existing meters that need replacements and this is scheduled to be completed before 2020.

2015 System Renewal

Total System Renewal expenditures in 2015 is forecasted to be $4.9 million or $1.8 million lower than the Bridge Year 2014. This decrease reflects a more typical level of expenditures in 2015 for renewal capital, similar to historic norms, and which will be a more normal level of investment moving forward in 2015 – 2019. Justification for these projects are more fully described in the attached DS Plan but essentially they are guided by outcomes of the METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

- Proposed 2015 OH Rebuilds: Total $2.4 million
  - Park Rd Wentworth To Stone including Lakefields, Beaupre, Tremblay, Kenora, Gaspe, Laurentian, Lakeview, Lakeside, Lakemount, Evangeline, Montieth, Bala, Wilson - Wentworth To Bloor: $1.3 million
  - Keewatin (Melrose, Applegrove, Oriole, Willowdale, Springdale): $745 thousand
  - Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary: $365 thousand
- Proposed 2015 UG rebuilds: – Forecasted Total expenditures $930 thousand. Projects over the materiality threshold include:
  - Sorrento Ave, Homestead Ct, Cooper Ct, Siena Ct and Salerno St: City still trying to resolve field clearance issues and has caused delays in project; carried over from 2014 into 2015; $150 thousand

- Southgate Dr, Southdale Ave, Southdown Dr, Southridge St: City still trying to resolve field clearance issues and has caused delays in project; carried over from 2014 into 2015; $140 thousand
- Down Crescent, Delmark Ct – Townhouse complex: $130 thousand
- Camelot Dr, Merlin Ct, Percival Ct, Lancelot Cres: $250 thousand
- Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave: $260 thousand

• Station 2015 Rebuilds – Forecasted Total expenditures $1 million. Projects over the materiality threshold include:
  - MS5 T1 Power transformer Replacement: Total $840 thousand
  - Station Breaker Replacement program (2014-2016) - For 2014 Forecast expenditure is $175 thousand; 2015 Forecast expenditure: $210 thousand and 2016 Forecast expenditure $140 thousand

• Annual Reactive or Emergency Capital Replacements - Forecast is $4.2 million for period 2015 to 2019, or $830 thousand annually. These capital replacements are nondiscretionary. Details and justification of these projects are described in previous sections of the Exhibit and in the DS Plan filed as a standalone document attached.

<u>2015 System Service:</u>

Total System Service expenditure forecast in the Test Year 2015 is $2.8 million similar to 2014 Bridge Year forecast expenditure of $2.8 million. Projects above material threshold include:

• Thornton TS Capacity Upgrades $1.5 million – Capital Contribution to HONI $3.0 million over 2015-2016 – Provide HONI TX with capital contributions to address Oshawa Requirement for 2 feeder positions at Thornton TS. Initial investment of $3.0 million spread over 2015 and 2016, or $1.5 million each year. Based on initial discussions, Hydro One has scheduled the replacement of both transformers at Thornton TS, which have reached their end of life, by the end of 2015, including the installation of a grounding neutral reactor to resolve short circuit capacity constraints for FIT installations. The intent was to provide OPUCN with two new feeder positions and upgrade the bus tie to provide feeder and station capacity. The estimate provided by Hydro One is approximately $3.0 million which is included in OPUCN DS plan, with $1.5 million included annually in 2015 and 2016 to smooth out the level of investments. Outcomes of recent Local Planning meeting indicates that this original proposal is now being deemed not viable as a long term solution to meet the load growth in the Region. Level of contributions to HONI for a new transmission station are still preliminary and subject to change, and may increase to $10 to $12 million.

- New Distribution Station (MS9) and associated primary overhead feeders (2015 to 2019 project) $750 thousand - Construct new distribution 44kV-13.8kV station (MS 9) and required 13.8kV distribution feeders to service new developments in North Oshawa. Estimated total expenditure $7.0 million (station) and $2.0 million (13.8KV feeder extensions). In 2008, OPUCN proposed the construction of the new substation MS9. With the decline in the economy and the uncertainty and delays in the opening of the highway 407 extension, the load growth in Oshawa did not materialize as originally forecasted and this project was placed on hold. With the opening of the 407 extension in 2015 along with the aggressive promotional efforts from the City of Oshawa to encourage new development, the load growth has started to materialize. On-going collaboration with the City, have confirmed the projected load forecast and given the timeline to construct a new substation (on average 3-4 years) OPUCN, with the support of the City, is resuming work on design and construction of this new substation in order to meet the now forecast load growth timing. OPUCN plans on utilizing the land previously purchased for this station. Existing substations do not have the capacity nor the feeder capabilities to extend to the north sections of Oshawa where the future load growth will surely occur. OPUCN will need to proceed in 2015 to issue an RFP/RFQ for a turn-key design, construction and commissioning to ensure additional distribution capacity is made ready in 2019. The following table summarizes the level of expenditures forecast annually from 2015 to 2019.

TABLE 2-39 - 2015 - 2019 SYSTEM SERVICES ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Services					
Thorton TS Capacity - HONI Contributions	1,500	1,500			
Wilson TS Capacity - HONI Contributions			1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation	750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders				1,000	1,000

- Grid Modernization - UG Distribution Automation Project (2014–2015) - Downtown Vaults Automation. Estimated forecast total expenditure over 2 years $1.43 million. This project will improve system reliability and provide visibility in UG downtown area through grid automation and smart technology. It will also provide communication infrastructure that can be linked to the planned Outage Management System (OMS). It involves automating the downtown underground system by installing relays on existing automation-ready switches and replacing existing switches with fully automated switches in 15 vault rooms. Communication infrastructure will be implemented through installation of a fiber optic network connecting the vault rooms to SCADA. The installation of ICCP system will complete the communication network that will provide visibility to our system to increase productivity and to better manage/operate the downtown distribution grid. Transformer primary and secondary monitors will also be introduced to existing transformers in 6 vault rooms where there are multiple customers to monitor transformer health, capacity and primary and secondary loading information for demand management.

- UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (CIBC Vault and Michael Starr) Carried over from 2014. Forecast 2015 expenditure $110 thousand.
- UG Distribution Automation Project - Phase 3 - Downtown Vaults Automation (Durham Tower, Bond Towers McLaughlin Square Vaults). Forecast 2015 Expenditures $438 thousand.

<u>2015 General Plant</u>

Total General Plant expenditure forecast in the 2015 Test year is $1.7 million or an increase of $1.0 million compared with 2014 Bridge Year Forecast. This is mainly due to the proposed completion of the Outage Management System (OMS). Projects above material threshold include:

- Outage Management System (OMS fully integrated with SCADA, GIS, AMI, CIS, IVR) Phase 2; - Forecast $850 thousand
- Fleet – Full delivery of the 85ft bucket truck - Forecast $270 thousand
- Miscellaneous fleet below the material threshold - Forecast $150 thousand
- One station van, two cube vans (for metering) and one trailer for pole delivery Forecast $ 420 thousand
- Facilities/Leasehold improvements – Forecast $175 thousand - Renovate Tech area for additional work station and washroom (100K) plus install pole yard storage for cable reels, and additional vehicle parking space ($75 thousand)

2016 Test Year Forecast (MIFRS) versus 2015 Test Year Forecast (MIFRS)

As indicated in Table 2-40, OPUCN's forecasted total capital expenditure in the Test Year 2016 is $11.6 million or $1.9 million lower than 2015 Test Year. This decrease is mainly due to the 2015 spend related to the Highway 407 Extension not in 2016 (net $1.3 million), along with $850 thousand in OMS expenditures in 2015 not recurring, partially offset by $400 thousand for replacement of the ODS system. All other expenditures are typical and in line with previous year spending.

TABLE 2-40 - 2016 TEST YEAR VS 2015 TEST YEAR CAPITAL PROJECTS ($000S)

Projects	2015 Test Year	2016 Test Year	Variance 2016 Test Year vs 2015 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,075	1,125	50
Service connections/requests	120	110	(10)
Service/Expansion Contributions	(650)	(675)	(25)
Hwy 407 Extension - Plant relocation	4,510	700	(3,810)
Hwy 407 contribution	(3,580)	(400)	3,180
Durham Region - Plant relocation	1,875	935	(940)
Durham Region Contribution	(506)	(235)	271
City of Oshawa - Plant relocation	680	595	(85)
City of Oshawa Contribution	(175)	(145)	30
Metering service connections	375	380	5
Remote Disconnect/Reconnect Metering	100	100	0
OEB's MIST Metering	150	150	0
MoE approved Micro Grid Project	110	45	(65)
System Access Total	4,084	2,685	(1,399)
System Renewal			
O/H Rebuilds	2,410	2,455	45
U/G Rebuilds	1,133	1,007	(126)
Station Rebuilds	510	640	130
Reactive/emergency Plant Replacement	830	830	0
System Renewal Total	4,883	4,932	49
System Services			
Thorton TS Capacity - HONI Contributions	1,500	1,500	0
MS9 - 44kV/13.8kV Substation	750	1,000	250
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	548	280	(268)
Smart Fault Indicators	25	25	0
Distribution System Supply Optimization	45	25	(20)
System Services Total	2,868	2,830	(38)
General Plant			
Fleet	420	415	(5)
Total Facilities Leasehold Improvements	225	50	(175)
Major Tools and Equipment	50	50	0
Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	850	0	(850)
Mobile Work force		50	50
ODS Replacement due to enhanced operational requirements not available with existing ODS		400	400
GIS Enhancements for operational needs including OMS		60	60
MAS Enhancements for operational needs		25	25
Office IT Capital Expenditure	130	130	0
General Plant Total	1,675	1,180	(495)
Miscellaneous			0
Total	**13,510**	**11,627**	**(1,883)**

2016 System Access

Total 2016 System Access expenditures is forecast to be $2.7 million or $1.4 million lower than the 2015 Test Year forecast due to the completion of Phase 1 of the Highway 407 extension in 2015, with no expenditures included in 2016.

- Subdivision Expansions – Similar to 2015, forecasted gross expenditure for 2016 is $1.1 million with forecasted contribution of $650 thousand. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Details and justification of these projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached.

  - Service connections/requests – 2016 connection requests are forecasted to be $110 thousand, $10 thousand less than 2015 Test Year. These service projects are non-discretionary and driven by customer requests. Details and justification for these projects are described in previous sections of the exhibit and in the DS Plan filed and attached as a standalone document.

  - Phase 2 - Eastern Construction General Partners (ECGP) Highway 407 Extension (2014-2016) – Total 2016 gross forecast is $700 thousand or net $300 thousand after contributions of $400 thousand. This project is forecast as per the current ECGP construction schedule and is a continuation of the Highway 407 extension Phase 1. Work in 2016 may involve clean up and review of any potential work necessary in Oshawa for Phase 2 extension. Please see attached DS Plan for details and justification of Project.

  - Durham Region and City of Oshawa road reconstruction – 2016 total gross expenditures are forecast at $1.5 million or net $1.1 million after contributions of $380 thousand. This is a similar forecast to 2015 forecast. Details and justification of these projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached. The following projects are over the material threshold:

- Region Relocate - Gibb St -East of Stevenson Rd to Simcoe St S: Net estimated expenditure $400 thousand
- Region Relocate - Victoria / Bloor St. - West City limits (Thornton) to Stevenson Intersection: Net estimated expenditure $300 thousand
- City Relocate - Gibb St - East of Stevenson Rd to Park Rd - North and south sides; Net estimated expenditure $190 thousand
- Miscellaneous City Projects below the Material Threshold – forecast net expenditure $260 thousand

- Metering - 2016 forecast is similar to 2015 and includes the projects listed in the table below. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document:

TABLE 2-41 – 2016 METERING FORECAST ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access					
Metering service connections	375	380	390	390	390
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125

<u>2016 System Renewal</u>

Total System Renewal expenditures in 2016 is forecast at $4.9 million similar to the Test Year 2015. This level of expenditures is more reflective of the typical expenditures for sustaining renewal capital, similar to historic pattern and which will be a more normal level of investment moving forward in 2015 – 2019. Justification for these projects is more fully described in the attached DS Plan but essentially they are guided by outcomes of the METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

Proposed 2016 OH Rebuilds: Forecasted Total $2.2 million

- Rossland - Ritson to Wilson: $550 thousand
- Athabasca, Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield: $835 thousand
- Eastlawn, Winter, Mackenzie, Labrador: $360 thousand
- Bloor St - Oliver to MS11: $ 510 thousand

- Pole Replacement Program (2016 – 2019): Total Forecast $800 thousand or $200 thousand annually based on approximately 10 -15 poles annually. OPUCN completed pole testing during 2004 – 2007. Best practice recommends pole testing to be conducted every 10 years, starting with the poles that are over 30 years old or which have previously identified risks. OPUCN therefore plans to start pole testing and inspection in 2015 on a systematic area by area basis, to identify poles in need of replacement. Pending the results, OPUCN will immediately replace poles that are in very poor condition or deemed urgent that impact public or employee safety, or at critical risk of failure. Poles that are identified as being in poor condition but not critical will be scheduled over the 2016 – 2019 period. Estimated annual gross expenditure $200 thousand based on approximately 10 -15 poles annually.
- Proposed UG rebuilds: – 2016 Forecasted Total expenditures $1million. Projects over the Material Threshold include:

- Northdale Ave,Mohawk St, BeatriceW: Townhouse complex: $147 thousand
- 1100 Oxford St: Townhouse complex $126 thousand

- Athabasca St, Suton Ct.: Townhouse complex$138 thousand
- MS10 - 10F1 & 10F6 Lead cable & lead potheads replacements: $180 thousand
- Aruba Cres, Aruba St, Waverly St N,Bermuda Ave, Antigua Cres: $338 thousand
- Miscellaneous UG Projects below Material Threshold – Forecast $78 thousand

• Station Rebuilds – 2016 total expenditures $500 thousand. Projects over the Material Threshold include:

- 2016 – 2018 Project - Replacement of 44kV Oil Circuit Breakers: Total $1.5 million or $500 thousand annually over 3 years. Based on METSCO's Asset condition assessment eleven (11) 44 kV circuit breakers will need to be replaced as they are in excess of 40 years old and are approaching end of life. More importantly, their technology is obsolete and replacement parts from suppliers are no longer available. OPUCN proposes to replace these with SF6 Vacuum Breakers but also intends to investigate alternative replacement options through an RFP to interested parties. OPUCN plans to replace these over the period 2016 -2018. Station Breaker Replacement program (2014 - 2016).

		2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000
44kV oil circuit breakers replace with SF6 in Outdoor enclosure. Start in 2016 with 4 breakers per year.	Obsolete, end of life 45+ years breaker counter defective - total 12 OCB in the system to be replaced		$500	$500	$500	

• Reactive or Emergency Capital Replacement - $830 thousand annually, $4.2 million total for period 2015-2019. These capital replacements are nondiscretionary. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

2016 System Service:

Total System Service expenditures forecasted in the Test Year 2016 is $2.8 million similar to 2015 Test Year forecast expenditure of $2.8 million. Projects above material threshold include:

- Thornton TS Capacity Upgrades – Capital Contribution to HONI of $3 million spread over 2015 and 2016, or $1.5 million each year, as per Table below. Details and justification of these projects are described in previous sections of the Exhibit and in the DS Plan filed as a standalone document attached. Level of contributions to HONI for station capacity are preliminary and subject to change, possibly to between $10 and $12 million pending outcomes of the Regional Planning and Local Planning meetings.
- New Distribution Station (MS9) and associated primary overhead feeders (2015 – 2019 project). For 2016, forecast expenditure is $1.0 million related to the installation of primary distribution feeders. Construction of new 44kV-13.8kV distribution station (MS 9) and required 13.8kV distribution feeders to service new developments in North Oshawa. Estimated total forecast is $7 million (station) and $2 million for required 13.8KV primary feeder extensions. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

The following table summarizes the level of expenditures for both Transmission and Distribution capacity forecasted annually from 2015 – 2019. Contributions to Hydro One are preliminary and subject to regional planning or local planning outcomes.

TABLE 2-42 - 2015 TO 2019 FORECAST SYSTEM SERVICES ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Services					
Thorton TS Capacity - HONI Contributions	1,500	1,500			
Wilson TS Capacity - HONI Contributions			1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation	750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders				1,000	1,000

- Grid Modernization - UG Self-Healing Distribution Automation Project (2016 – 2019) – Installation of a downtown “smart grid” automated system. Estimated total expenditure over 4 years $310 thousand. Subsequent to the Project, “Distribution Automation in OPUCN downtown underground system”. OPUCN will, in the final phase, install remote switching devices and intelligent software application to allow the “intelligent” system to automatically and remotely make operational decisions in fault detection, fault isolation, and switching to perform load transfers or restoration.

2016 General Plant

Total General Plant expenditures forecasted in the 2016 Test year is $1.18 million or a decrease of $495 thousand compared with 2015 Test Year Forecast. This is mainly due to the proposed completion of the Outage Management System (OMS) no longer accounted for in 2016 but includes the proposed replacement of the ODS system of $400 thousand. Projects above material threshold include:

- ODS replacement/enhancements as existing ODS is not equipped to meet future operational business needs – Forecast $400 thousand

- Fleet – new 46ft single bucket with increased capacity and reach to replace old vehicle - Forecast $375 thousand

2017 Test Year Forecast (MIFRS) versus 2016 Test Year Forecast (MIFRS)

As indicated in Table 2-43 2017 below, OPUCN's forecast total capital expenditure in the Test Year 2017 is $12.4 million or $745 thousand higher than 2016 Test Year total expenditures. This increase is mainly due to the construction of MS9 ($1.75 million), partially offset by reduced expenditures in system renewal ($460 thousand) and general plant ($425 thousand).

TABLE 2-43 - 2017 TEST YEAR VS 2016 TEST YEAR CAPITAL PROJECTS ($000S)

Projects	2016 Test Year	2017 Test Year	Variance 2017 Test Year vs 2016 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,125	1,150	25
Service connections/requests	110	100	(10)
Service/Expansion Contributions	(675)	(690)	(15)
Hwy 407 Extension - Plant relocation	700		(700)
Hwy 407 contribution	(400)		400
Durham Region - Plant relocation	935	1,065	130
Durham Region Contribution	(235)	(265)	(30)
City of Oshawa - Plant relocation	595	470	(125)
City of Oshawa Contribution	(145)	(120)	25
Metering service connections	380	390	10
Remote Disconnect/Reconnect Metering	100	100	0
PrePaid Metering		150	150
OEB's MIST Metering	150	125	(25)
MoE approved Micro Grid Project	45		(45)
System Access Total	2,685	2,475	(210)
System Renewal			
O/H Rebuilds	2,455	2,055	(400)
U/G Rebuilds	1,007	1,087	80
Station Rebuilds	640	500	(140)
Reactive/emergency Plant Replacement	830	830	0
System Renewal Total	4,932	4,472	(460)
System Services			
Thorton TS Capacity - HONI Contributions	1,500		(1,500)
Wilson TS Capacity - HONI Contributions		1,000	1,000
MS9 - 44kV/13.8kV Substation	1,000	3,250	2,250
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	280	10	(270)
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)		350	350
Smart Fault Indicators	25	25	0
Distribution System Supply Optimization	25	35	10
System Services Total	2,830	4,670	1,840
General Plant			
Fleet	415	440	25
Total Facilities Leasehold Improvements	50	50	0
Major Tools and Equipment	50	50	0
Mobile Work force	50	50	0
ODS Replacement due to enhanced operational requirements not available with existing ODS	400		(400)
GIS Enhancements for operational needs including OMS	60	60	0
MAS Enhancements for operational needs	25	25	0
Office IT Capital Expenditure	130	80	(50)
General Plant Total	1,180	755	(425)
Miscellaneous			0
Total	**11,627**	**12,372**	**745**

<u>2017 System Access</u>

Total 2017 System Access expenditures is forecast to be $2.5 million or $210 thousand lower than the 2016 Test Year forecast. The projected lower spend is mainly due to no 407 extension costs forecast partially offset by higher metering expenditures.

- Subdivision Expansions – $1.1 million with forecast contributions of $690 thousand. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Although Load growth is projected to grow annually at 3%, OPUCN has chosen to project a reasonable expenditure consistent with current trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Service connection requests – 2017 connection requests are forecast at $100 thousand $10 thousand less than 2016 Test Year. These service projects are non-discretionary and driven by customer requests, and OPUCN chose to apply a reasonable forecast expenditure based on trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Durham Region and City of Oshawa road reconstruction – In 2017, Total actual expenditures are forecast to be $1.5 million with a net total expenditure of $1.15 million after total contributions of $385 thousand. This is similar to 2016 forecast. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document. The following projects are over the material threshold:
    - Region relocate - Gibb St/ Olive Ave Interconnection from Simcoe St to Ritson Rd: Net estimated expenditure $210 thousand
    - Region Relocate - Manning Ave / Adelaide Ave - Garrard Rd to Thornton: Net estimated expenditure $120 thousand

- Region relocate - Thornton Rd from Champlain Ave to King Region relocate: Net estimated expenditure $470 thousand
- City Relocate - Bloor St Realignment (Phase 1); Net estimated OPUCN expenditure $260 thousand
- City Relocate - Cubert Street, Bloor St to College Ave: Net estimated OPUCN expenditure $90 thousand

• Metering - Forecast is similar to 2016 forecast and includes the projects in the table below. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document. New to 2017 is prepaid metering: OPUCN plans to install prepaid metering where residential customers will pay in advance and have a credit put into the system. A prepaid metering system benefits both the customer and the utility by giving the customer control of their electrical usage spending while allowing the utility to be paid in advance for future usage from customers that have historically been difficult to collect payment from. The anticipated 2017 expenditure is approximately $150 thousand.

TABLE 2-44 – METERING 2015 – 2019 ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access					
Metering service connections	375	380	390	390	390
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125

<u>2017 System Renewal</u>

Total System Renewal expenditures in 2017 is forecasted to be $4.5 million or $460 thousand lower than the 2016 Test Year. This is primarily due to lower forecast expenditures in OH rebuilds. This level of expenditures is reasonable given the typical expenditures for sustaining renewal capital, which will be of a more normal level of investment moving forward in 2015 – 2019. Justification for these projects are more fully described in the attached DS Plan but essentially they are guided by outcomes of the METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

- Proposed 2017 OH Rebuilds: Forecast Total $1.9 million
  - Central Park Blvd N - Brentwood, Homewood to Harwood: $575 thousand
  - Lansdowne - Dover, Digby, Surrey, Sussex: $335 thousand
  - Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct:$480 thousand
  - Rebuild Fisher St, Albert S, Avenue St & Quebec St: $ 250 thousand
  - GrenFell South of Gibb, Harland, Montrane: $215 thousand
- Pole Replacement Program (2016 – 2019): Total Forecast over 4 years $800 thousand or $200 thousand annually. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Proposed 2017 UG rebuilds: – 2017 Forecasted Total expenditures $1.1 million.
  - 1010 Glen St - Townhouse complex: $160 thousand
  - Annandale St, Capilano Cres and Capiland Crt: Subdivision $170 thousand
  - Cherry Down Dr & Sunnybrae Dr: Townhouse complex $185 thousand
  - Birkdale St. Muirfield St Pinehurst to Subbingham Subdivision $195 thousand

- Proposed 2017 Station Rebuilds – Total expenditures $500 thousand. This is $140 thousand lower than 2016 expenditures as the 13.8kV breaker replacement program was completed in 2016.

- Replacement of 44kV Oil Circuit Breakers, a 2016 – 2018 Project. Total $1.5 million or $500 thousand annually. Details and justification of this project are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

		2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
44kV oil circuit breakers replace with SF6 in Outdoor enclosure. Start in 2016 with 4 breakers per year.	Obsolete, end of life 45+ years breaker counter defective - total 12 OCB in the system to be replaced		$500	$500	$500	

- Reactive or Emergency Capital Replacements $830 thousand - Similar to previous years. These capital replacements are nondiscretionary. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

<u>2017 System Service</u>

Total System Service expenditures forecasted in the Test Year 2017 is $4.7 million or $1.8 million higher than the test year 2016. This is primarily due to the additional expenditures forecast for the ongoing construction of MS9 and grid modernization. Contributions to Hydro One for Station capacity is proposed to end for Thornton TS in 2016, and then continues with Wilson TS in 2017 as reflected in the table below. Justifications for these projects are described in more detail in the attached DS Plan. Projects above the materiality threshold include:

- Wilson TS Capacity Upgrades – Capital contribution to HONI based on preliminary forecast $3.5 million spread over 3 years 2017 – 2019. Please see table below. Details and justification of these projects are described in previous sections of the Exhibit and in the DS Plan filed as a standalone document attached. Level of expenditures related to Contributions to HONI for station capacity are preliminary and subject to change, possibly to between $10 and $12 million pending outcomes of the Regional Planning and Local Planning meetings.

- New Distribution Station (MS9) and associated primary overhead feeders (2015 – 2019 project). For 2017, forecast expenditure is $3.25 million. Construction of new 44kV-13.8kV distribution station (MS 9) and required 13.8kV distribution feeders to service new developments in North Oshawa. Estimated total forecast is $7.0 million (station) and $2 million for required 13.8KV primary feeder extensions. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

The following table summarizes the level of expenditures for both Transmission and Distribution capacity forecasted annually from 2015 – 2019. Contribution amounts forecast to Hydro One are preliminary and subject to Regional Planning or Local Planning outcomes.

TABLE 2-45 – SYSTEM SERVICES 2015 - 2019 ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Services					
Thorton TS Capacity - HONI Contributions	1,500	1,500			
Wilson TS Capacity - HONI Contributions			1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation	750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders				1,000	1,000

- Grid Modernization (2017 – 2019 Project) – OH automated self-healing Intelli-Rupters switches. Forecast expenditure over 3 year period is $955 thousand, or approximately $350 thousand annually. OPUCN plans to install 8 switches on 13 identified feeders over the period 2016 – 2019. That is 5 switches in 2017, 2018 and 3 switches in 2019. OPUCN has had proven successful operations with its pilot installation whereby fault was identified, switches automatically operated successfully as designed to quickly isolate the fault and minimize number of customers affected by fault, thereby improving overall reliability. OPUCN plans to install more Self-Healing Intelli-Rupter switches on its poor performing feeders.

2017 General Plant

Total General Plant expenditures are forecast to be $755 thousand in the 2017 Test year, a decrease of $425 thousand compared with 2016 Test Year Forecast. This is mainly due to the proposed completion of the ODS project. Projects above the materiality threshold are:

- Fleet – new 46ft single bucket with increased capacity and reach to replace old vehicle. Forecast cost $375 thousand

2018 Test Year Forecast (MIFRS) versus 2017 Test Year Forecast (MIFRS)

As indicated in Table 2-462018, OPUCN's forecast total capital expenditure in the Test Year 2018 is $12.5 million or $100 thousand higher than 2017 Test Year total forecast of $12.4 million. This slight increase is mainly due to higher expenditures related to system renewal partially offset by reduced metering expenditures.

TABLE 2-46 - 2018 TEST YEAR VS 2017 TEST YEAR CAPITAL PROJECTS ($000S)

Projects	2017 Test Year	2018 Test Year	Variance 2018 Test Year vs 2017 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,150	1,180	30
Service connections/requests	100	100	0
Service/Expansion Contributions	(690)	(705)	(15)
Durham Region - Plant relocation	1,065	1,080	15
Durham Region Contribution	(265)	(280)	(15)
City of Oshawa - Plant relocation	470	460	(10)
City of Oshawa Contribution	(120)	(110)	10
Metering service connections	390	390	0
Remote Disconnect/Reconnect Metering	100	100	0
PrePaid Metering	150		(150)
OEB's MIST Metering	125	125	0
System Access Total	2,475	2,340	(135)
System Renewal			
O/H Rebuilds	2,055	2,510	455
U/G Rebuilds	1,087	921	(166)
Station Rebuilds	500	500	0
Reactive/emergency Plant Replacement	830	830	0
System Renewal Total	4,472	4,761	289
System Services			
Wilson TS Capacity - HONI Contributions	1,000	1,000	0
MS9 - 44kV/13.8kV Substation	3,250	2,000	(1,250)
MS9 Proposed OH distribution feeders		1,000	1,000
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	10	10	0
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)	350	350	0
Smart Fault Indicators	25	25	0
Volt-Var optimization & Reduction in Distribution Losses	0	225	225
Distribution System Supply Optimization	35	35	0
System Services Total	4,670	4,645	(25)
General Plant			
Fleet	440	190	(250)
Total Facilities Leasehold Improvements	50	50	0
Major Tools and Equipment	50	50	0
Mobile Work force	50		(50)
GIS Enhancements for operational needs including OMS	60	60	0
MAS Enhancements for operational needs	25	50	25
ODS/CIS Enhancements for operational needs		50	50
Office IT Capital Expenditure	80	280	200
General Plant Total	755	730	(25)
Miscellaneous			0
Total	**12,372**	**12,476**	**104**

<u>2018 System Access</u>

Total 2018 System Access expenditures is forecast to be $2.3 million or $135 thousand lower than the 2017 Test Year forecast. The projected lower spend is related to the prepaid metering project expenditure in 2017 that is not in 2018.

- Subdivision Expansions – $1.18 million forecast gross expenditure with forecasted contribution of $705 thousand similar to 2017. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Although Load growth is projected to grow annually at 3%, OPUCN has chosen to project expenditure consistent with current trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Service connections/requests – Similar to 2017 Test Year, the connection requests for 2018 are forecasted to be $100 thousand. These service projects are non-discretionary and driven by customer requests, and OPUCN chose to apply a reasonable forecast expenditure based on trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.
- Durham Region and City of Oshawa road reconstruction – $1.6 million with a net total forecast of $1.2 million after contributions of $390 thousand. This is similar to 2017 forecast. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document. The following projects are over the materiality threshold:
    - Region Relocate - Stevenson Rd - CPR Belleville to Bond St: Net estimated expenditure $400 thousand
    - Region Relocate - Rossland Rd - Ritson Rd to Harmony Rd: Net estimated expenditure $400 thousand

- City Project: Bloor St Realignment (Phase 2): Total Net expenditure $210 thousand

- Metering - Forecast is similar to 2017 forecast except for the prepaid metering project in 2017 and includes the projects listed in the table below. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.

TABLE 2-47 – METERING 2015 - 2019 ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access					
Metering service connections	375	380	390	390	390
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125

<u>2018 System Renewal</u>

Total System Renewal expenditures in 2018 are forecasted to be $4.8 million or $289 thousand higher than the 2017 Test Year. This level of expenditures is typical of normal requirements for sustaining renewal capital, which will be at a more normal level of investment moving forward in 2015 – 2019. Justification for these projects are more fully described in the attached DS Plan but essentially they are guided by outcomes of the METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

- Proposed 2018 OH Rebuilds: Forecasted Total $2.3 million
  - Julianna & Bernhard: $335 thousand
  - Mary - Rossland to Aberdeen: $340 thousand

- Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle: $665 thousand
- Riverside South - Palace and Hosein: $340 thousand
- Riverside North - Regent, East Haven, East Grove, Eastdale, Eastborne, East Glen, Florian Crt: $630 thousand

- Pole Replacement Program (2016 – 2019): Total Forecast over 4 years of $800 thousand or $200 thousand annually. Details and justification of this projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached
  - Proposed 2018 UG rebuilds: – Forecasted Total expenditures $921 thousand
    - Gladfern, Galahad, Gentry, Gaylord- Subdivision: $405 thousand
    - Traddles, Dickens, Wickham, Subdivision $321 thousand
    - Outlet Dr - Birchcliffe Ct, Lakeview Park Ave & Valley Dr Townhouse: $195 thousand
  - Proposed 2018 Station Rebuilds – 2018 Forecasted Total expenditures $500 thousand. This is similar to 2017 forecast expenditures.
    - Replacement of 44kV Oil Circuit Breakers: Total $1.5 million or $500 thousand annually over 3 years. Based on METSCO's Asset condition assessment eleven (11) 44 kV circuit breakers will need to be replaced as they are in excess of 40 years old and are approaching end of life. More importantly, their technology is obsolete and replacement parts from suppliers are no longer available. OPUCN proposes to replace these with SF6 Vacuum Breakers but also intends to investigate alternative replacement options through an RFP to interested parties. OPUCN plans to replace these over the period 2016 -2018.

		2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000
44kV oil circuit breakers replace with SF6 in Outdoor enclosure. Start in 2016 with 4 breakers per year.	Obsolete, end of life 45+ years breaker counter defective - total 12 OCB in the system to be replaced		$500	$500	$500	

- Reactive or Emergency Capital Replacements - $830 thousand similar to previous years. These capital replacements are nondiscretionary and driven by factors beyond our control or under emergency conditions. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

2018 System Service

Total System Service expenditures forecast in the 2018 Test Year is $4.7 million similar to the test year 2017. Projects above material threshold include:

- Wilson TS Capacity Upgrades – Capital Contribution to HONI - preliminary forecast $3.5 million spread over 3 years 2017 – 2019. Please see table 2-48 below. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document. Level of expenditures related to contributions to HONI for station capacity are preliminary and subject to change, possibly to between $10 million and $12 million pending outcomes of the Regional Planning and Local Planning meetings.

- New Distribution Station (MS9) and associated primary overhead feeders to service major developments in North Oshawa, (2015 – 2019 project) Estimated total forecast is $7.0 million (station) and $2.0 million for required 13.8KV primary feeder extensions. For 2018, forecast expenditure is $3.0 million as per Table below. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document. The following table summarizes the expenditures for both Transmission and Distribution capacity forecast annually from 2015 –

2019. Contributions to Hydro One are preliminary and subject to Regional Planning or Local Planning outcomes.

TABLE 2-48 – 2015 - 2019 TRANSMISSION AND DISTRIBUTION CAPACITY SPEND ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Services					
Thorton TS Capacity - HONI Contributions	1,500	1,500			
Wilson TS Capacity - HONI Contributions			1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation	750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders				1,000	1,000

- Grid Modernization – OH automated self-healing Intelli-Rupters switches. Forecast expenditure over the 3 year period 2017 to 2019 is $955 thousand or approximately $350 thousand annually. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

- Voltage Monitoring (2018 – 2019) - Volt-Var optimization and Reduction in Distribution Losses. Estimated total expenditure over 2 years $450 thousand or $225 thousand per year. OPUCN presently needs better visibility into the condition of the network, to help identify and reduce its line losses. The outcomes of the project will help OPUCN achieve better operational system efficiencies thereby providing customers with some reduction in billing. Volt-Var controls can help identify the cause of line losses and ultimately reduce them over time. The Volt-Var system enables the detailed and accurate modeling of the distribution system components and connections. It rapidly identifies the optimal voltage and VAR operation strategy, using advanced mixed-integer optimization algorithms. Volt-Var system comprises of system software distribution system switches, fault indicators, and communication devices, which will be installed over the period of two years.

2018 General Plant

Total General Plant expenditures forecast in the 2018 Test year are $730 thousand or a decrease of $25 thousand compared with 2017 Test Year Forecast. This is mainly due to lower fleet requirements offset by higher expenditures in IT, primarily replacement of servers reaching or at their end of useful life.

2019 Test Year Forecast (MIFRS) versus 2018 Test Year Forecast (MIFRS)

As indicated in Table 2-49 below, OPUCN's forecast total capital expenditure in the Test Year 2019 is $10.8 million or $1.7 million lower than 2018 Test Year total forecast of $12.5 million. This decrease is mainly due to the proposed completion of MS9 substation installation in 2018 resulting in no MS9 station expenditure forecast in 2019, along with a decrease in general plant expenditures resulting from expenditures returning to normal level of activity.

TABLE 2-49 - 2019 TEST YEAR VS 2018 TEST YEAR CAPITAL PROJECTS ($000S)

Projects	2018 Test Year	2019 Test Year	Variance 2019 Test Year vs 2018 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	
System Access			
Subdivision Expansions	1,180	1,215	35
Service connections/requests	100	100	0
Service/Expansion Contributions	(705)	(730)	(25)
Durham Region - Plant relocation	1,080	1,055	(25)
Durham Region Contribution	(280)	(255)	25
City of Oshawa - Plant relocation	460	470	10
City of Oshawa Contribution	(110)	(120)	(10)
Metering service connections	390	390	0
Remote Disconnect/Reconnect Metering	100	100	0
OEB's MIST Metering	125	125	0
System Access Total	2,340	2,350	10
System Renewal			
O/H Rebuilds	2,510	2,117	(393)
U/G Rebuilds	921	904	(17)
Station Rebuilds	500	1,000	500
Reactive/emergency Plant Replacement	830	830	0
System Renewal Total	4,761	4,851	90
System Services			
Wilson TS Capacity - HONI Contributions	1,000	1,500	500
MS9 - 44kV/13.8kV Substation	2,000		(2,000)
MS9 Proposed OH distribution feeders	1,000	1,000	0
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements	10	10	0
Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)	350	255	(95)
Smart Fault Indicators	25	25	0
Volt-Var optimization & Reduction in Distribution Losses	225	225	0
Distribution System Supply Optimization	35	35	0
System Services Total	4,645	3,050	(1,595)
General Plant			
Fleet	190	170	(20)
Total Facilities Leasehold Improvements	50	50	0
Major Tools and Equipment	50	50	0
GIS Enhancements for operational needs including OMS	60	60	0
MAS Enhancements for operational needs	50	50	0
ODS/CIS Enhancements for operational needs	50	50	0
Office IT Capital Expenditure	280	80	(200)
General Plant Total	730	510	(220)
Miscellaneous			0
Total	**12,476**	**10,761**	**(1,715)**

2019 System Access

Total 2019 System Access expenditures is forecast to be $2.3 million similar to the 2018 Test Year forecast.

- Subdivision Expansions – Forecast gross expenditure for 2019 is $1.2 million with contributions of $730 thousand similar to 2018. These projects are non-discretionary and are directly related to growth in the City of Oshawa. Although load growth is projected to grow annually at 3%, OPUCN has chosen to project a reasonable expenditure consistent with current trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.

- Service connections/requests – Similar to 2018 Test Year, the connection requests for 2019 are forecast to be $100 thousand. These service projects are non-discretionary and driven by customer requests, and OPUCN chose to apply a reasonable forecast expenditure based on trend. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.

- Durham Region and City of Oshawa road reconstruction –Total expenditures are forecast to be $1.5 million with a net total forecast of $1.1 million after contributions of $375 thousand. This is similar to 2018 forecast. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document. The following projects are over the material threshold:

  - Region Relocate - Rossland Rd from Harmony Rd East to Townline Rd: Forecasted Net expenditure $320 thousand

  - Region Relocate - Bloor St, Harmony Rd to Grandview Ave: Estimated Net expenditure $480 thousand

  - City Relocate - Wilson Rd South - King St to Athol St (West side): Net forecast OPUCN expenditure $120 thousand

  - City Relocate - Simcoe St North - Colbourne St to Brock St: Net forecast OPUCN expenditure $160 thousand

- Metering - Forecast of $615 thousand is similar to 2018 forecast and includes the projects listed in the table below. Details and justification of these projects are described in previous sections of the exhibit and in the attached DS Plan filed as a standalone document.

TABLE 2-50 – METERING 2015 - 2019 ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access					
Metering service connections	375	380	390	390	390
Remote Disconnect/Reconnect Metering	100	100	100	100	100
PrePaid Metering			150		
OEB's MIST Metering	150	150	125	125	125

2019 System Renewal

Total System Renewal expenditures in 2019 are forecast to be $4.85 million or $90 thousand higher than the 2018 Test Year of $4.76 million. The slight increase is due to the replacement power transformer at MS5 partially offset by lower expenditures in OH plant rebuilds.

This level of expenditures is typical of normal requirements for sustaining renewal capital, which will be at a more normal level of investment moving forward in 2015 – 2019. Justification for these projects are more fully described in the attached DS Plan but essentially they are guided by outcomes of the METSCO's Asset Condition Assessment Report and driven by required replacement of assets with some or all of the following characteristics - at or reaching their end of useful life; very high failure risks; are legacy standard installations or are obsolete; impact safety and reliability. Project specifics are as follows:

- Proposed 2019 OH Rebuilds: Forecasted Total $1.9 million
  - King St E 10F1 (Keewatin to Townline): $500 thousand
  - Vimy Ave, Lasalle Ave: $175 thousand

- Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham: $1,042 thousand
- Grandview, Beaufort and Newbury: $200 thousand

* Pole Replacement Program (2016 – 2019): Total Forecast over 4 years $800 thousand or $200 thousand annually. Details and justification of these projects are described in previous sections of the exhibit and in the DS Plan filed as a standalone document attached.
* Proposed 2019 UG rebuilds: – Forecasted Total expenditures $904 thousand.
  - Marwood Dr Townhouse Complex: $290 thousand
  - Central Park Blvd North, Exeter St and Trowbridge: $256 thousand
  - Ormond Dr, EverGlades, Palmetto, Pompano Ct: $234 thousand
  - Beaufort Court: $124 thousand
* Station (MS5) Rebuild – Forecast expenditures $1.0 million $500 thousand higher than 2018 expenditures due to the proposed replacement of the MS5 T2 power transformer partially offset by the completion of the 44kV Oil Circuit Breakers in 2018. The existing Power transformer is to be replaced with a new 25kVA Transformer unit c/w Oil Containment. Based on METSCO's Asset condition assessment this transformer unit is greater than 30 years and is starting to show increased combustible gas content. OPUCN will be monitoring this unit and plans to replace in 2019 as it approaches the end of its useful life with replacement essential to maintaining reliability.
* Reactive or Emergency Capital Replacements - $830 thousand similar to previous years. These capital replacements are nondiscretionary and driven by factors beyond our control or under emergency conditions. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

<u>2019 System Service:</u>

Total System Service expenditures forecasted in the Test Year 2019 is $3.0 million or $1.6 million lower than 2018 forecast. This decrease is mainly due to the expected completion of MS9 substation installation in 2018 with no more MS9 station expenditure forecast in 2019. Contributions to Hydro One for station capacity is proposed to end for Thornton TS and then continues with Wilson TS as reflected in the table below. Justifications for these projects are described in more detail in the attached DS Plan filed as a standalone document. Projects above material threshold include:

- Wilson TS Capacity Upgrades – $3.5 million preliminary forecast for capital contribution to HONI spread over 3 years from 2017 to 2019. Please see table below. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document. Level of contributions to HONI for station capacity are preliminary and subject to change, possibly to between $10 million and $12 million pending outcomes of the Regional Planning and Local Planning meetings.
- New Distribution Station (MS9) and associated primary overhead feeders (2015 – 2019 project). For 2019, forecast expenditure is $1.0 million related to the installation of primary distribution feeders. Construction of new 44kV-13.8kV distribution station (MS 9) and required 13.8kV distribution feeders to service new developments in North Oshawa. Estimated total forecast is $7.0 million (station) and $2.0 million for required 13.8KV primary feeder extensions). Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

The following table summarizes the level of expenditures for both Transmission and Distribution capacity forecasted annually from 2015 – 2019. Contributions to Hydro One are preliminary and subject to Regional Planning or Local Planning outcomes.

TABLE 2-51 – 2015 TO 2019 TRANSMISSION AND DISTRIBUTION CAPACITY SPEND ($000S)

Projects	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Services					
Thorton TS Capacity - HONI Contributions	1,500	1,500			
Wilson TS Capacity - HONI Contributions			1,000	1,000	1,500
MS9 - 44kV/13.8kV Substation	750	1,000	3,250	2,000	
MS9 Proposed OH distribution feeders				1,000	1,000

- Grid Modernization – OH automated self-healing Intelli-Rupters switches. Forecast expenditure over 3 year period is $955 thousand or approximately $350 thousand annually. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.
- Voltage Monitoring (2018 – 2019) - Volt-Var optimization and Reduction in Distribution Losses. Estimated total expenditure over 2 years $450 thousand or $225 thousand per year. Details and justification of these projects are described in previous sections of the Exhibit and in the attached DS Plan filed as a standalone document.

<u>2019 General Plant</u>

Total General Plant expenditures forecast in the 2019 Test year is $510 thousand a decrease of $220 thousand compared with 2018 Test Year Forecast of $730 thousand. This is mainly due to the proposed completion of the IT systems server replacements project in 2018, and hence not included in 2019. Other general plant expenditures are similar to 2018 forecast and in line with normal level of expenditures.

CAPITALIZATION POLICY

OPUCN's last rebasing in 2012 (EB-2011-0073) was completed based on MIFRS and included appropriate changes to its capitalization policy to exclude from capital any costs which are not directly attributable to an item of PP&E, as part of the transition to MIFRS. This capitalization policy under MIFRS is consistent with IFRS, which OPUCN will formally adopt for financial reporting purposes on January 1, 2015. This application does not include any further changes to capitalization policies.

Under IFRS, the cost of an item of PP&E includes only costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The term "directly attributable" is not defined under IFRS. However, there must be a direct relationship that is established by fact between a cost element and a construction or acquisition activity in order for such cost to be "directly attributable" to such activities and, on this basis capitalized as PP&E. The capital treatment for each of the main cost elements is outlined below.

Material Costs

Material costs include stocked items held in warehouses and issued out to each capital project, as well as materials purchased and delivered to capital project sites directly. These costs represent the purchase price, and initial delivery and handling costs of the materials. OPUCN capitalizes material costs as they are directly attributable costs of bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Labour Costs

Labour costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management are capitalized. Labour costs are allocated to individual capital projects through timesheets.

Third Party Contract Costs

OPUCN engages third party sub-contractors to perform capital construction services. Third party costs are capitalized as they are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Fleet Costs

Fleet costs are allocated to individual capital projects through the OPUCN timesheet system, similar to the process used for labour costs. Vehicle hourly charge rates are calculated by totaling fuel, repairs and maintenance, depreciation and other directly attributable costs, then dividing by the estimated number of available for use hours.

CAPITALIZATION OF OVERHEAD

Where it can be factually established that a direct relationship exists between overhead costs and the construction or acquisition of an item of PP&E, such costs are capitalized as part of the item of PP&E.

Payroll Burden

OPUCN considers employee benefit costs for staff working on specific capital projects as directly attributable costs and accordingly capitalizes such costs. This is done by way of an uplift percentage added to each hour of labour charged to capital projects.

The payroll burden rate used in OPUCN's last rebasing in 2012 (EB-2011-0073) was 82%, which was also the rate used in 2013. The labour burden rate is recalculated each year in order to incorporate any changes to benefit and other directly attributable costs. An updated actuarial valuation of the Post Retirements Benefit liability done for year ended December 31, 2013 resulted in a significant reduction in the annual expense projected for 2014. These revised projections resulted in a revised labour burden rate of 63% for 2014. The 63% rate is included in each of the years 2015 through 2019 in this application.

OPUCN has completed Appendix 2-DA which provides a summary of the overhead costs included in the capitalized costs of self-constructed assets.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Service Quality Indicators

OPUCN tracks its performance on the OEB's Electricity Service Quality Requirements (ESQR). The OEB's *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Ontario Energy Board Act, 1998*.

As required by the OEB, OPUCN records and submits these performance measures which are compared with the OEB's established expected ESQR levels, to evaluate OPUCN's performance in appointment scheduling, service accessibility and emergency response.

The Table 2-52 below summarizes OPUCN last 5 years of reported ESQRs.

TABLE 2-52– APPENDIX 2-G REPORTED ELECTRICITY SERVICE QUALITY REQUIREMENTS (ESQR)

While achieving or exceeding all ESQR metrics since 2011, one area of focus for OPUCN remains to be answering customer calls and providing information relevant to customers' enquiries. OPUCN plans to enhance its IVR and CIS systems and leverage the integration of this with its proposed Outage Management System (OMS) to provide faster response and better information to customers, internal and external stakeholders.

Metric	OEB Minimum Standard	2009	2010	2011	2012	2013
Connection of New Services (LV)	90% within 5 days	100.00%	92.30%	91.00%	96.52%	97.60%
Connection of New Services (HV)	90% within 10 days	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Scheduling	90% on a yearly basis	100.00%	99.90%	100.00%	100.00%	100.00%
Appointments Met	90% on a yearly basis	100.00%	99.10%	99.90%	99.90%	98.90%
Missed Appointments Rescheduled	100% on a yearly basis	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65% within 30 seconds	56.10%	59.20%	71.30%	71.30%	71.50%
Telephone Call Abandon Rate	10% or less after 30 seconds	5.50%	4.30%	2.10%	2.20%	1.60%
Written Responses to Inquiries	80% within 10 days	100.00%	100.00%	99.40%	99.40%	100.00%
Emergency Response (Urban)	80% within 60 minutes	100.00%	100.00%	100.00%	100.00%	85.71%
Emergency Response (Rural)	80% within 120 minutes	100.00%	100.00%	100.00%	100.00%	100.00%

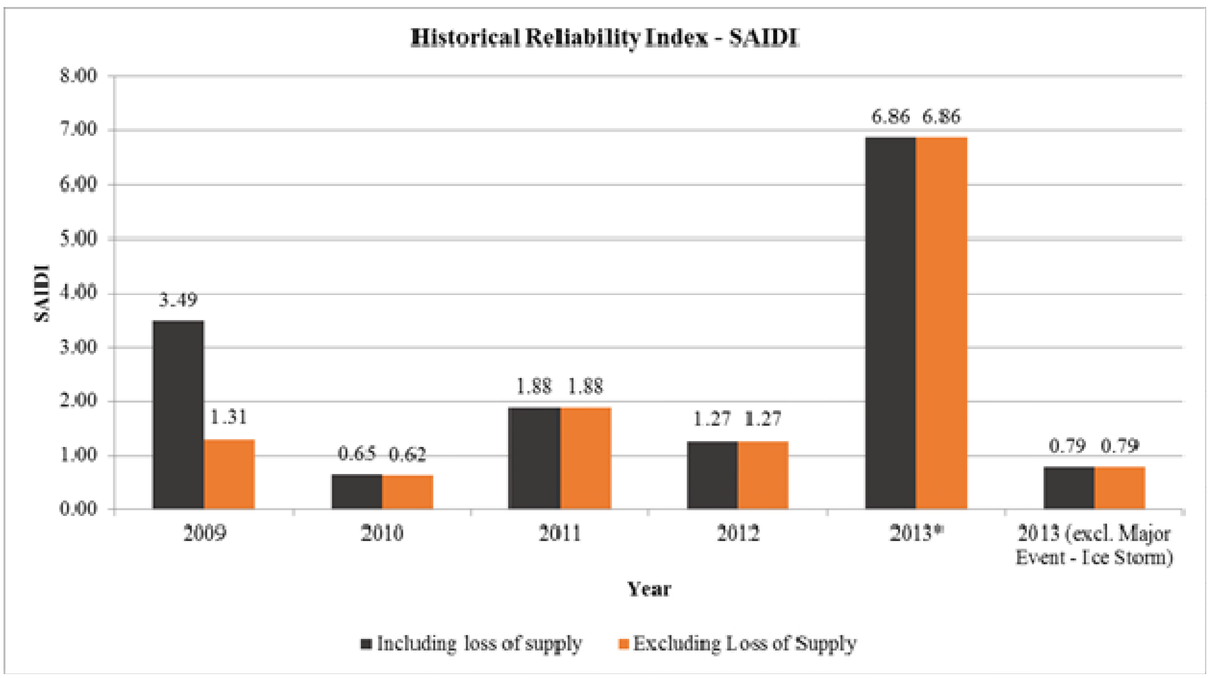
Reliability Indicators

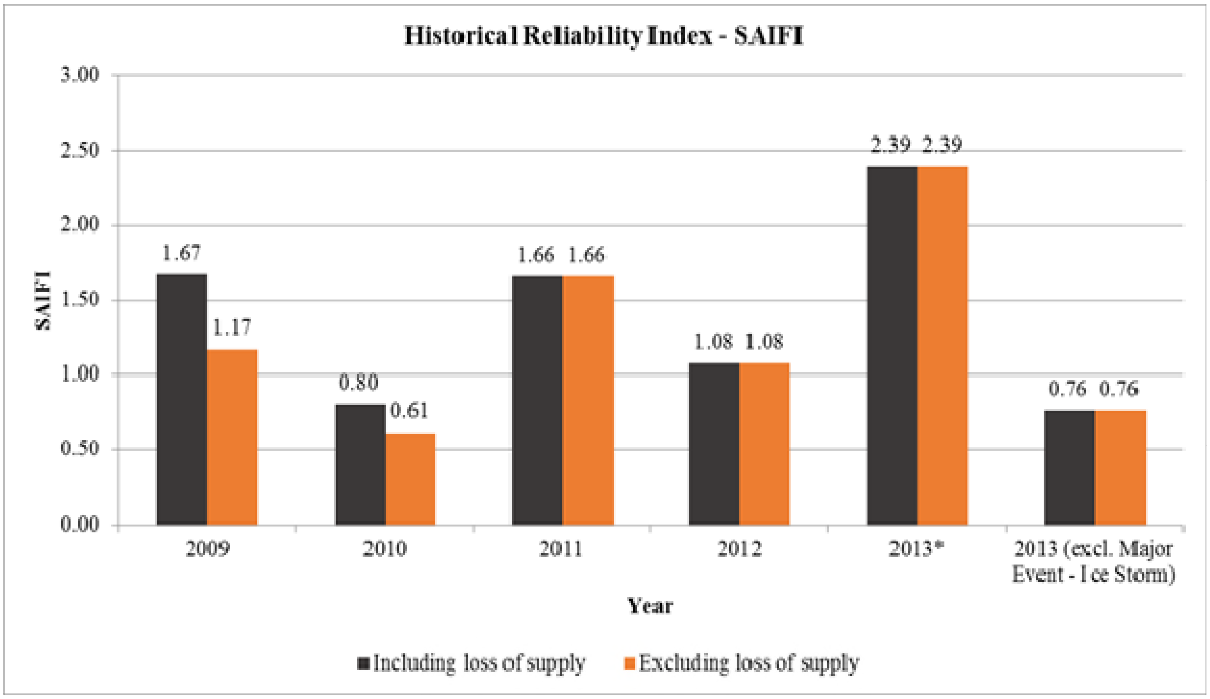
OPUCN tracks and reports to the OEB, the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"). The Table 2-53 below summarizes OPUCN last 5 years of reported SAIDI and SAIFI.

TABLE 2-53– APPENDIX 2-G REPORTED SERVICE RELIABILITY INDICATORS (SAIDI & SAIFI)

	Includes Outages Caused by Loss of Supply						Excludes Outages Caused by Loss of Supply					
	2009	2010	2011	2012	2013	2013*	2009	2010	2011	2012	2013	2013*
SAIDI	3.49	0.65	1.88	1.27	0.79	6.86	1.31	0.62	1.88	1.27	0.79	6.86
SAIFI	1.67	0.80	1.66	1.08	0.76	2.39	1.17	0.61	1.66	1.08	0.76	2.39

* Includes December 2013 Ice Storm





Overall, not including the impact of the December 2013 Ice Storm, the foregoing reliability performance indicators show a positive trend in OPUCN's reliability performance, with each year still being within the OEB suggested threshold. This is due to capital investments completed to address significant root causes of outages as they are identified.

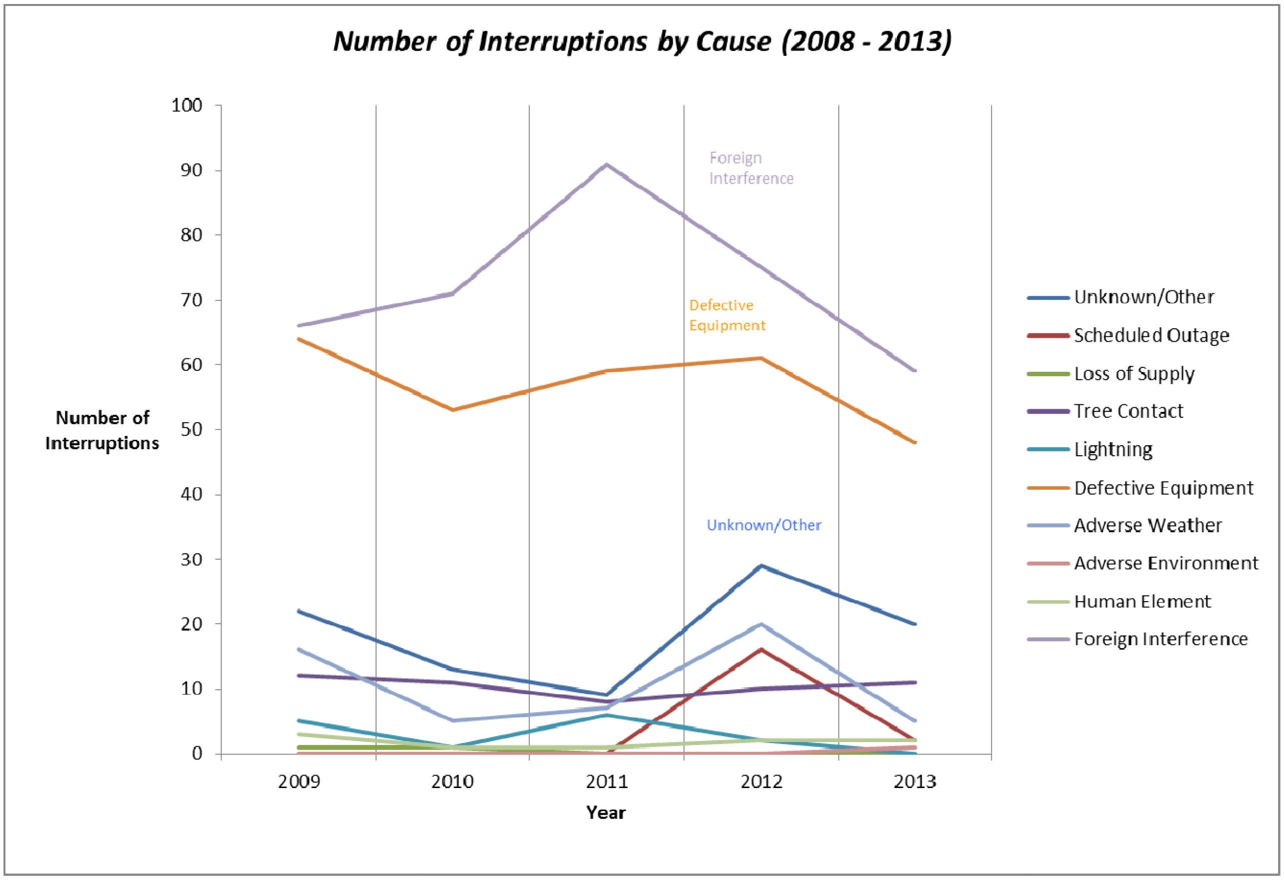
For example, as illustrated in the Graph xx below, outages since 2009 were primarily due to defective equipment and foreign interference. *Defective equipment* is defined as equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance. Outages due to *foreign interference* is defined as customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

In 2011, OPUCN identified defective porcelain insulators and switches along with squirrel contact as major contributors to the significant decrease in its reliability performance compared to 2010. Consequently in 2012, OPUCN included in its Asset Management Plan and completed, capital expenditures to install animal guards on all its overhead distribution transformers. OPUCN also implemented a 2 - 3 year program to replace all porcelain insulators and switches with polymer type units. This has resulted in major reductions in outages specific to these causes and hence to overall number of outages.

In 2012, OPUCN had a total of 215 outages and in 2013, it experienced a total of 148 outages, a reduction of 31%. Out of the 148 total number of outages in 2013:

- 40% were due to animal (squirrel) contact (59 out of 148). By comparison, in 2012 there were 75 outages caused by animal contact. 2013 saw a reduction of 21% in this category.
- 32% were due to defective equipment (48 out of 148). Again by comparison, in 2012 there were 61 outages caused by defective equipment, 2013 saw a reduction of 21% in this category.

Total number of Outages by Root Cause (2008 – 2013)



Moving forward in its plan to continually improve system reliability and customer satisfaction, OPUCN has included the following investments in its 5 year DS Plan:

System Renewal investments:

OPUCN has an aging infrastructure, and it continues to identify projects to improve system reliability and minimize outage impacts to its customers. With the guidance of the Asset Condition Assessment (ACA) report, along with its maintenance and inspection reports and underground primary cable fault analysis, OPUCN identifies assets in need of replacement due to high level risk of in service failure, are reaching or are at end of its useful life, and schedules these projects based on criticality and level of priority as indicated by its Asset Investment Prioritization (AIP) tool/model. OPUCN, over the 5 year planning period, has included on average, an annual planned level of investment of approximately $4 million for such asset renewal projects.

Grid Modernization and Business Operational system improvements:

While OPUCN's reliability trend is positive and outages continue to decline, OPUCN is listening to its customers on outage issues and intends to provide its customers with better visibility and more timely information related to outages. OPUCN is continuing with its implementation of distribution automation, including intelligent and or self-healing devices, equipment and systems, to automatically sectionalize and isolate faulted sections, allow faster restoration time and minimize the number of customers being impacted.

OPUCN also plans to complete the installation of an Outage Management System (OMS) installation by December 2015. The OMS will be fully integrated with its SCADA, GIS, AMI, CIS and IVR, so that OPUCN will also be able to proactively identify customers without electrical power, without waiting for customers to call in and report the outage. This OMS will help OPUCN:

Proactively provide more frequent and timelier updates to our customers during an outage (e.g. the area affected by the outage, number of customers affected, possible cause and when power may be restored).

Reduce the duration, frequency and impact of interruptions to our customers.

Assist in automation of the outage detection, restoration, and reporting process.

Oshawa PUC Inc.

August 2014

Building a better
working world

ALLOWANCE FOR WORKING CAPITAL FOR THE 2015-2019 RATE PERIOD ("TEST YEARS") FOR OSHAWA PUC INC. ("OPUC")

Table of Contents

1.0 EY Disclaimer

- Our work has been performed in accordance with the terms of our engagement letter dated 20 September, 2013, and comprises this presentation and any oral explanations given during the presentation of our findings.
- In preparing this Report, Ernst & Young LLP ("EY") has been provided with and in making the comments herein, it has relied upon unaudited financial information, "Oshawa PUC Inc." ("OPUC" or the "Company") books and records, financial information prepared by the Company, and discussions with management of the Company ("Management"). EY has not audited, reviewed or otherwise attempted to verify the accuracy or completeness of such information and, accordingly, EY expresses no opinion or other form of assurance in respect of such information contained in this Report. Readers are cautioned that since projections are based upon assumptions about future events and conditions that are not ascertainable, the actual results will vary from the projections, even if the assumptions materialize, and the variations could be significant.
- Our analysis has been prepared on the information available and provided to us within the context of our work and is therefore reliant on the accuracy and completeness of this data.
- No person on the EY team has any responsibility for making any management decisions or performing any management function.

2.0 Introduction

The purpose of this document is to provide a calculation of the allowance for working capital for the 2015 - 2019 rate period ("Test Years") for Oshawa PUC Inc. (**"OPUC")**.

The amount of funds (i.e. the working capital) required to finance the day-to-day operations of a regulated utility is included as part of the rate base for ratemaking purposes and is a generally accepted practice for utilities in Canada.

In Ontario, the Ontario Energy Board **("OEB")** regulates the province's electricity and natural gas sectors in the public interest. Under Chapter 2, section 2.5.13 (Allowance for Working Capital) of the OEB's Filing Requirements for Electricity Distribution Rate Applications ("**OEB Filing Requirements**"), the OEB prescribes that utilities may calculate their allowance for working capital using one of two approaches as follows:

1) the 13% allowance approach; or

2) the filing of a lead/lag study.

The only exception to the above requirement is if the applicant has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is used.

In its last cost of service application for 2012, OPUC used a working capital allowance of 15% per the OEB's prior working capital allowance approach. In order to calculate its working allowance for the Test Years, OPUC has engaged EY to provide assistance for the methodology and calculation necessary to fill a detailed lead/lag study to the OEB.

Based on that analysis, it proposes that its working capital allowance be set at 12.74**%**.

3.0 Method and Approach

Generally, a power and utilities corporation provides services prior to receipt of payment from ratepayers and also incur a delay in payment for goods and services consumed by the corporation. A lead/lag study is used to analyze transactions throughout the year to determine the number of days between the time services are rendered and payment is received (revenue lag), and the number of days between the time expenditures are incurred and payment is made for such services (expense or payment lead).

Once the revenue lags and expense leads are determined in days, they are weighted based on their respective dollar amount. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the applicant's rate base determination.

The working capital requirement is expressed as a percentage of Cost of Power, Operations, Maintenance and Administration **("OM&A")** costs and other budgeted costs to determine the Allowance for Working Capital for a particular year.

OPUC's lead/lag study analyzes OPUC's revenue lag and expense lead based on 2012 and 2013 historical data. These values were used to calculate working capital requirements for the 2014 bridge year and the 2015 - 2019 Test Years based on forecast expenses. The working capital allowance percentage calculated for OPUC was determined at 12.74%.

Methodology for calculating lead and lag for services over period of time

When a service is provided to the company over a period of time, the service is considered to have been provided evenly over the midpoint of the period unless information is provided on actual receipt of service date. For calculation purposes, Mid-point = ([End Date]-[Start Date])/2.

When Start Date and End Date are unknown, the service is evenly distributed over the duration of the service period. For calculation purposes, Mid-point = ([Service Period in days])/2.

4.0 Revenue Lag

OPUC earns revenue primarily from electricity distribution based on a fixed monthly service fee with a variable charge reflecting consumption and non-regulated activities. Revenues can be broken into:

- Residential;
- Commercial/Industrial;
- Large Users (greater than 5,000 kW); and
- Street Lighting.

For electricity distribution customers, revenue lag refers to the time elapsed from service provided to customers to the time payments are received by the company (i.e. the "lag"). For OPUC, revenue lag can consist of the following components:

1) Service lag: weighted average days gap from when service is provided to the customer to the date when the meter read is taken showing consumption;

2) Billing lag: weighted average days gap from when the meter read information is available to when bill is prepared and sent out to customer;

3) Collections lag: weighted average days gap from when bill is sent out to customers to when payment is received; and

4) Payment processing lag: weighted average days gap from when payment is received from a customer via various payment methods to when funds are available to the company.

OPUC also earns other revenue from completion of service work such as temporary cable installations, pole rentals for third-party communications lines and other miscellaneous operational services. Completion of service revenue lag is calculated in sub section 2.6.

Table 1 shows a summary of the 2012 and 2013 source of revenue and customer type

Source of Revenue	Revenue Lag 2012 (days)	2012 Amount ($)	% of total	Weighted Lag 2012 days	Revenue Lag 2013 days	2013 Amount ($)	% of total	Weighted Lag 2013 (days)
Electricity distribution (Residential, commercial / industrial, large users, street lighting, other revenue)	60.84	115,930,715	99%	60.51	62.24	121,082,455	98%	60.91
Completion of Services	77.51	633,561	1%	0.42	-24.29	2,658,193	2%	-0.52
Total		116,564,276	100%	60.93		123,740,648	100%	60.39

4.1 Service Lag – electricity distribution

Service lag for electricity distribution is the amount of time from when service is provided to customers to the date the meter read is performed. Meters are read on a monthly basis for residential, commercial / industrial, large users (greater than 50kW), and street lighting customers.

Based on the monthly meter read cycle and consolidated financial information, the weighted average service lag calculated for all electricity distribution based customers is 20.41 days for 2012 and 21.44 days for 2013. This method of calculation takes the average end of month unbilled revenues in both years and is converted into days of sales. For OPUC, this lag is longer than the typical midpoint of 15 days due to heavier weighting of larger revenue customers near end of month.

Table 2 shows a summary of the 2012 and 2013 electricity distribution customers and their respective service lags

Customer Type	Freq. of Meter Read	2012 Amount ($)	Weight	Service Lag 2012 (days)	2013 Amount ($)	Weight	Service Lag 2013 (days)
Electricity distribution (Residential, commercial / industrial, large users, street lighting, other revenue)	Monthly	115,930,715	100%	20.41	121,082,455	100%	21.44
Total		115,930,715	100%	20.41	121,082,455	100%	21.44

4.2 Billing Lag – electricity distribution

Billing lag for electricity distribution is the time from when meter read information is available to when the bill is prepared and sent out to customers. Based on a process review, this lag is dependent on the availability of spot rate information provided by Independent Electricity System Operation ("**IESO**"). Rate information is typically available 10 business days following the meter read date. The billing system takes on average 3 days to produce the invoice from the date the rate information is available. The weighted average billing lag is 17.00 days for all customer segments.

Table 3 shows a summary of the 2012 and 2013 electricity distribution customers and their respective billing lags

Customer Type	Billing lag (days)	2012 Amount ($)	Weight	Billing Lag 2012	2013 Amount ($)	Weight	Billing Lag 2013 (days)
Electricity distribution (Residential, commercial / industrial, large users, street lighting, other revenue)	17.00	115,930,715	100%	17.00	121,082,455	100%	17.00
Total		115,930,715	100%	17.00	121,082,455	100%	17.00

4.3 Collection Lag – electricity distribution

Collection lag for electricity distribution is the time from the invoice date to the payment date. The collection lag is based on average days sales outstanding for each month in 2012 and 2013. Days sales outstanding is calculated using month-end accounts receivables against the daily sales for each respective month.
The average collection lag for 2012 and 2013 were 21.93 days and 22.30 days, respectively.

Table 4 shows schedules for 2012 and 2013 electricity distribution customers by monthly accounts receivables, sales and days sales outstanding ("DSO")

Month	2012 AR ($)	2012 Sales (incl HST) ($)	2012 DSO	2013 AR ($)	2013 Sales (incl HST) ($)	2013 DSO
January	8,621,347	12,109,249	22.07	7,145,042	13,078,717	16.94
February	8,585,264	12,044,313	22.10	8,312,164	11,116,643	23.18
March	7,253,461	10,288,543	21.86	9,045,331	12,630,566	22.20
April	8,040,385	10,598,873	23.52	8,803,925	10,529,526	25.92
May	6,960,374	9,314,084	23.17	7,481,134	10,312,190	22.49
June	6,401,592	10,104,920	19.64	8,301,779	9,515,305	27.05
July	8,109,612	13,121,633	19.16	7,525,979	12,174,410	19.16
August	8,611,755	11,256,054	23.72	8,613,383	13,646,841	19.57
September	9,588,859	11,049,954	26.90	8,169,114	9,207,726	27.50
October	5,980,441	8,649,888	21.43	7,334,893	10,844,331	20.97
November	6,721,068	10,550,312	19.75	7,825,589	9,752,259	24.88
December	7,123,147	11,141,111	19.82	8,108,450	14,113,022	17.81
Average			**21.93**			**22.30**

4.4 Payment Processing – electricity distribution

Payment processing lag for electricity distribution is the number of days from when a payment is received (from customers via various payment methods) to when funds are available to the company. Customer payments are typically made via cheque and credit cards. Cheques are received centrally and posted to customer accounts the day after receipt and funds are deposited into OPUC's account the next day. Credit card payments are posted to customer accounts the same day and funds are available to OPUC in two business days.

The weighted average payment processing lag based on sampling of transactions processed is 1.50 days for funds to be available from date of payment receipt for 2012 and 2013.

4.5 Revenue Lag – electricity distribution

For electricity distribution, the revenue lag consists of: service lag, billing lag, collections lag and payment processing lag. Electricity distribution makes up 99% of all revenue in 2012 and 98% of all revenue in 2013. The revenue lag is 60.84 for 2012 and 62.24 for 2013, respectively.

Table 5 shows the component breakdown of revenue lag for electricity distribution

Type of revenue lag	2012 (days)	2013 (days)
Service Lag	20.41	21.44
Billing Lag	17.00	17.00
Collections Lag	21.93	22.30
Payment Processing Lag	1.50	1.50
Total	60.84	62.24

4.6 Revenue Lag – completion of services

Revenue from completion of service work includes temporary cable installations, pole rentals for third-party communications lines and other miscellaneous operational services.

OPUC typically requires an upfront deposit before commencing work. Due to the nature of these services, OPUC is required to keep a portion of spare parts inventory on hand. Revenue for these projects are billed and paid through the Sundry Accounts Receivable GLs.

To assess the revenue lag, all jobbing transactions from these GL accounts were downloaded for 2012 and 2013. Revenue lag was calculated based on average work-in-progress and AR accounts for completion of services projects against annual revenue for those accounts.

Average revenue lag for completion of services was 77.51 days in 2012 and (24.29) in 2013, respectively.

Table 6 shows the calculation of revenue lag for completion of services

Year	Average Work-In-Progress (days) (A)	Average Accounts Receivable ($) (B)	Average WIP and AR (C) = (A) + (B)	Total Annual Revenue ($)(D)	Revenue Lag (days) (E) = (C) / (D) * 365
2012	28,799	105,740	134,539	633,561	77.51
2013	-13,451	-163,480	-176,931	2,658,193	-24.29

5.0 Expense Lead

Expenses for OPUC can be divided into the following categories:

- Cost of Power;
- Operations, maintenance and administrative expenses ("OM&A");
  - Payroll and benefits;
  - Suppliers: Subcontracts, Communication, Vehicle, Rent, Insurance, Other;
- Municipal Taxes;
- Interest on Long Term Debt;
- Payments in Lieu of Taxes;
- Debt Retirement Charge; and
- Harmonized Sales Tax.

Expense lead refers to the number of days elapsed from goods or services received by OPUC to the time payment(s) is made. For OPUC, expense lead is calculated for each category.

Table 7 shows a summary of the 2012 and 2013 source of expense categories

Expenses	2012 Amount ($)	Expense Lead	% of total	2013 Amount ($)	Expense Lead	% of total
Cost of Power	96,181,988	19.70	83%	102,012,056	20.89	83%
OM&A	11,240,450	5.35	10%	11,210,095	13.80	9%
Interest on Long Term Debt	2,010,000	6	2%	1,910,000	6	2%
Payments in Lieu of Taxes	-711,000	12.5	-1%	240,000	12.5	0%
Debt Retirement Charge	7,547,228	30.35	6%	7,532,929	30.5	6%
Total – not including HST	116,268,666	18.81	100%	122,905,080	20.59	100%

5.1 Cost of Power

OPUC pays for cost of power based on invoices received from IESO and embedded generators. Based on month end average accounts payable for power against total supply expenses for the year, the average monthly expense lead for 2012 and 2013 are 19.70 days and 20.89 days, respectively.

Table 8 shows the calculation of expense lead for Cost of Power for 2012 and 2013

Cost of Power Expenses	2012	2013
Average Power Accounts Payable at month end (net of HST)	5,191,378	5,839,341
Total Power expenses (net of HST)	96,181,987	102,012,056
Expense Lead: (Average AP / Total Power expenses) x365	19.70	20.89

5.2 Operations, Maintenance and Administrative ("OM&A") expenses

OM&A expenses consists of payroll and benefits, supplier expenses for subcontracts, communications, vehicles, rent, insurance, and other miscellaneous OM&A expenses and Municipal tax

Table 9 shows the calculation of expense lead for OM&A Expenses categories for 2012 and 2013

OM&A Expenses categories	2012				2013			
	Expense Lead	Amount	Weight Factor	Weighting Lead	Expense Lead	Amount	Weight Factor	Weighting Lead
Payroll and Benefits	10.01	5,647,692	50.24%	5.03	10.42	5,667,950	50.56%	5.27
Supplier categories	-2.89	4,937,695	43.93%	-1.27	15.80	4,884,105	43.57%	6.89
Other miscellaneous	35.43	505,754	4.50%	1.59	36.61	505,748	4.51%	1.65
Municipal Tax	-25.00	149,309	1.33%	-0.33	-25.00	152,292	1.36%	-0.34
Total OM&A		11,240,450	100%	5.35		11,210,095	100%	13.80

Payroll and Benefits

- Employees are paid on bi-weekly basis. Payments are released and deposited into employee accounts three days after payment run is triggered

- Payroll withholdings, including the employer portion of Canadian Pension Plan and Employment Insurance, are remitted to Canadian Revenue Agency within three business days after pay day
- Employer Health tax is remitted on the15th of each month based on the previous month's payroll
- Workers Safety and Insurance Board remittances are made on 22nd - 23rd of each month based on the previous month's payroll
- Group pension plan for OPUC is administered by the Ontario Municipal Retirement System ("OMERS"). Remittances to OMERS are made on the 22nd- 23rd each month for the previous month
- Group Insurance Plan is administered by The Mearie Group. Payments to the program are made in advanced on the last business day of each month for the following month
- OPUC has an employee assistance program. Payments to the program are made in advanced on the last business day of each month for the following month

Based on the information, detailed income statements and sampling of transactions, the expense lead for payroll and benefits calculated for 2012 and 2013 are 10.01 and 10.42 days, respectively.

Table 10 shows the calculation for expense lead for payroll and benefits 2012 and 2013

Categories	Expense 2012	Expense 2013	Lead days	Weighted Factor 2012	Weighted Factor 2013	Weighted Lead 2012	Weighted Lead 2013
Payroll	6,470,904	6,963,427	10.00	76.76%	77.60%	7.68	7.76
Pension OMERS	576,910	674,396	35.00	6.84%	7.52%	2.40	2.63
Employer Health Tax	128,132	135,293	30.00	1.52%	1.51%	0.46	0.45
WSIB	83,340	61,260	35.00	0.99%	0.68%	0.35	0.24
Medical	759,536	697,481	-15.00	9.01%	7.77%	-1.35	-1.17
CPP	178,604	189,471	13.00	2.12%	2.11%	0.28	0.27
UIC (Employer)	82,918	91,987	13.00	0.98%	1.03%	0.13	0.13
Meal Allowance	3,314	13,588	2.00	0.04%	0.15%	0.00	0.00
Life Insurance	96,472	99,481	15.00	1.14%	1.11%	0.17	0.17
Long Term Disability	50,269	46,699	-15.00	0.60%	0.52%	-0.09	-0.08
Total Benefits	1,959,495	2,009,656		23.24%	22.40%	2.33	2.65
Total Payroll + Benefits before allocation of expenses	8,430,399	8,973,083					
Allocated OM&A expenses	-2,782,707	-3,305,133					
Net Payroll + Benefits	5,647,692	5,667,950		100%	100%	10.01	10.42

Supplier expenses

Key areas of OM&A expense for OPUC can be grouped into supplier categories. Expense lead is calculated based on key supplier expenses for each category, and by determining the average time to pay the supplier invoice. It is important to know that supplier payments are issued on a weekly basis by OPUC. Details on supplier categories are as follows:

- Subcontractors – reviewed 75% and 90% of 2012 and 2013 category spend. Majority of suppliers' bills are invoiced on a monthly basis. Based on a weighted average gap between payment date and invoice date, expense lead for 2012 and 2013 was 44.96 and 49.32 days, respectively;
- Communications – reviewed 70% of 2012 and 2013 category spend. Largest supplier (55-60% spend) was billing services two weeks in advance. Based on gap between payment date and invoice date, expense lead for 2012 and 2013 was (13.48) and (12.76) days, respectively;
- Vehicle – reviewed 70% of non-capitalized category spend for 2012 and 2013. Based on gap between payment date and invoice date, expense lead for 2012 and 2013 was 34.81 and 33.59 days, respectively;
- Rent – reviewed 100% of 2012 and 2013 category spend. City of Oshawa issues bill for rent month in advance. Based on gap between payment date and invoice date, expense lead for 2012 and 2013 was (0.11) and (3.67) days as payments were made on a weighted average of 15 days and 11 days after rent invoice;
- Insurance – reviewed 75% of 2012 and 2013 category spend. Insurers generally issue bills for the previous month of coverage. Based on gap between payment date and invoice date, expense lead for 2012 and 2013 was 9.62 and 5.94 days, respectively; and
- Pre-paids – Many suppliers such as software maintenance and other maintenance contracts receive pre-payments for services covering a 12-month period. Based on midpoint of service period, lead was calculated as -206.76 days in 2012 and -96.78 days in 2013.

Based on the above information, the expense lead for OM&A key categories expenses calculated for 2012 and 2013 are -2.89 and 15.80 days, respectively.

Table 11 shows the calculation of expense lead for supplier categories OM&A 2012 and 2013

Suppliers Categories	2012				2013			
	Expense Lead (days)	Amount ($)	Weight	Weighted Lead (days)	Expense Lead (days)	Amount ($)	Weight	Weighted Lead (days)
Subcontractor	44.96	1,654,505	45.93%	20.65	49.32	1,654,343	46.72%	23.04
Communi-cation	-13.48	609,376	16.92%	-2.28	-12.76	633,957	17.90%	-2.28
Vehicle	34.81	349,300	9.70%	3.38	33.59	335,573	9.48%	3.18
Rent	-0.11	286,544	7.95%	-0.01	-3.67	292,263	8.25%	-0.30
Insurance	9.62	261,494	7.26%	0.70	5.94	318,498	8.99%	0.53
Pre-paids	-206.76	441,278	12.25%	-25.33	-96.78	306,249	8.65%	-8.37
Total Key categories		3,602,497	72.96%	-2.89		3,540,883	72.50%	15.80
Other categories		1,335,198				1,343,222		
Total suppliers expenses		4,937,695	100%	-2.89		4,884,105	100%	15.80

Other miscellaneous OM&A expenses

OPUC pays fees to the related Holding company for management and corporate governance services on a monthly basis in the final week of month for work done in the current month. Expense lead for both 2012 and 2013 was 12.50 days.

Interest on customer deposits are paid upon customer request at the end of October for the previous year of service. Based on information contained in OPUC's income statement, the expense lead for both 2012 and 2013 was 487 days.

Table 12 shows the calculation of expense lead for other miscellaneous OM&A 2012 and 2013:

Expenses categories (exclude Provision for doubtful accounts)	2012				2013			
	Expense Lead (days)	Amount ($)	Weight Factor	Weighting Lead (days)	Expense Lead (days)	Amount ($)	Weight Factor	Weighting Lead (days)
Interest on customer deposits	487.00	24,478	4.84%	23.57	487.00	25,754	5.09%	24.79
Management Fees	12.50	480,000	94.91%	11.86	12.50	480,000	94.77%	11.85
Total miscellaneous expenses		505,754	100%	35.43		506,502	100%	36.64

5.3 Municipal Taxes

Municipal taxes are paid in advance via quarterly payments. First two payments are paid based on estimates due February 28th and April 30th. Last two payments based on actual tax rates for the year due July 31st and September 30th. Total amounts paid were $149,309 for 2012 and $152,292 for 2013.
Based on detailed income statement for 2012 and 2013, the expense lag for 2012 and 2013 are -25.00 days.

5.4 Interest on Long Term Debt

On December 21, 2011, OPUC renewed external debt of $7 million with a rate of interest of 3.565%. Interest on this long term debt is paid on a monthly basis on the 21st of every month. Based on a detailed monthly income statement, the total interest paid was $2.010m in 2012 and $1.910m in 2013.
Based on the above information, the expense lead for interest on long term debt is 6.00 days.

5.5 Payments in Lieu of Taxes ("PIL")

Monthly installments on current year PILs are made to the Ontario Electricity Financial Corporation ("OEFC") on the 27th or 28th of each month. A true-up payment is typically made in the following year. $711,000 was refunded in 2012 for an initial tax due of $47,000. $240,000 was paid in 2013 for an initial tax due amount of $158,000. The expense lead on payments in lieu of taxes is 12.50 days for both 2012 and 2013.

5.6 Debt Retirement Charge ("DRC")

DRCs are collected by OPUC from customers to pay down the debt of the former Ontario Hydro. The amounts are remitted to OEFC on a monthly basis (by cheque) 1 or 2 days before the due date (generally the 17th or 18th of month).

Based on a detailed monthly trial balance, the 2012 and 2013 DRC payments were $7,547,228 in 2012 and $7,532,929 in 2013. The average DRC outstanding at month end were $627,745 and $629,635 in 2012 and 2013, respectively.

The expense leads for debt retirement charges are 30.35 days and 30.50 days in 2012 and 2013, respectively.

5.7 Harmonized Sales Tax

OPUC generally remits HST on last day of month for the previous month. The following categories are subject to HST:

- Customer revenues including electricity distribution and completion of services;
- Cost of Power; and
- OM&A expenses excluding Labour, Benefits, Management Fees, Bank Charges, Customer deposits and insurance.

HST for Customer Revenue

OPUC collects HST from customers and remits to the Canada Revenue Agency on the last day of each month covering the previous month. HST lead represents the gap between collections lag and HST payments lead (45 days).

Lead / Lag for HST on Revenue in 2012 and 2013 were 22.77 days and 23.70 days, respectively.

Table 13 shows 2012 HST for Revenues

GST / HST Category	2012 Revenue ($)	13% HST ($)	Lead (Lag) days	Weight Factor	Weighted Lead (Lag) days
Electricity distribution	115,930,715	15,070,993	23.07	99%	22.95
Completion of Services	633,561	82,363	-32.51	1%	-0.18
Total	116,564,276	15,153,356		100%	22.77

Table 14 shows 2013 HST for Revenues

GST / HST Category	2013 Revenue ($)	13% HST ($)	Lead (Lag) days	Weight Factor	Weighted Lead (Lag) days
Electricity distribution	121,082,455	15,740,719	22.70	98%	22.21
Completion of Services	2,658,193	345,565	69.29	2%	1.49
Total	123,740,648	16,086,284		100%	23.70

HST Cost/Benefit

OPUC pays HST on power purchased from IESO and embedded generators, general and administrative expenses, and other miscellaneous OM&A expenses. OPUC can claim the HST paid and obtain a refund from HST owing from revenue (i.e. collected from customers). IESO invoices are received on a monthly basis around the 15th of each month.

The expense lead is calculated based on the difference between the HST return dates, typically the last day of each month, and payment dates on cost of power invoices. HST is prepaid and then refunded, resulting in negative expense lead or lag.

Table 15 shows 2012 HST Expense Lead

HST Category	2012 Amount ($)	13% HST ($)	Lead (Lag) days	HST Cost (Benefit)($)
	A	B = A * 13%	C	D = B*C/365
Revenue	-116,564,276	-15,153,356	22.77	-945,358
Cost of Power	96,181,988	12,503,658	-25.30	866,692
Supplier Expenses	4,937,695	641,900	-47.89	84,227
Capital Expense HST	7,290,376	947,749	0.04	-104
Total		-1,060,048		5,433

Table 16 shows 2013 HST Expense Lead

HST Category	2013 Amount	13% HST	Lead (Lag) days	HST Cost (Benefit)
	A	B = A * 13%	C	D = B*C/365
Revenue	-123,740,648	-16,086,284	23.70	-1,044,340
Cost of Power	102,012,056	13,261,567	-24.11	875,873
Supplier Expenses	4,884,105	634,934	-29.20	50,790
Capital Expense HST	5,717,996	743,339	4.33	-8,818
Total		-1,446,444		-126,495

6.0 Inventory Lag

Inventory for OPUC consists of items used for network maintenance as well as other type of supplies (e.g. spare transformers and reels). To calculate the inventory gap, all transactions for inventory for 2012 and 2013 were analyzed excluding non-relevant entries (e.g. vehicle hours and other discrepancies). Inventory lag was calculated by taking the average end of month inventory against the total cost of goods sold ("COGS") x 365 days.

Based on COGS, the average inventory lag was 60.22 days in 2012 and 48.94 days in 2013.

Inventory lag is related to OM&A expense and included in the working capital requirements calculations.

Table 17 shows Inventory Lag calculation for 2012 and 2013

Plant Materials and Operation supplies	2012	2013
Average End of Month Inventory value	$618,963	$751,275
Total inventory consumed over 12 months (in COGS)	$3,751,488	$5,603,425
Total expenses (OM&A - supplier & other)	$5,443,449	$5,389,853
Average Inventory lag (in days of COGS)	60.22 days	48.94 days
Average Inventory lag (in days of OM&A expenses)	41.50 days	50.88 days

7.0 Working Capital Requirement

The working capital allowance for OPUC for Test years 2015 to 2019 is based on 2012 and 2013 historical information. For 2012, the working capital allowance is calculated as $14.1 million or 13.08% of the Cost of Power and OM&A budgeted expenses. In 2013, it is calculated as $14.0m or 12.40%.

Table 18 shows Working Capital Requirement for test year 2015 expenses based on 2012 historical information

Expense item description	Revenue Lag (days)	Inventory Lag (days)	Expense Lead (days)	Net lag (lead) days	Working capital factor	Expenses from financial statement	Working capital requirement
	A	B	C	D=A+B-C	E=G/F	F	G=F x D/365
Cost of Power	60.93		19.70	41.23	11%	96,181,988	10,863,798
OM&A - payroll & benefits	60.93		10.01	50.92	14%	5,647,692	787,892
OM&A - supplier & other	60.93	41.50	0.67	101.76	28%	5,443,449	1,517,653
OM&A - Municipal Taxes	60.93		-25.00	85.93	24%	149,309	35,150
Interest on Long Term Debts	60.93		6.00	54.93	15%	2,010,000	302,478
Payment in lieu of Charges	60.93		12.50	48.43	13%	-711,000	-94,334
Debt Retirement Charges	60.93		30.35	30.58	8%	7,547,228	632,264
Sub-Total						116,268,666	14,044,900
HST						1,060,048	5,433
Total (Including HST)						117,328,714	14,050,333
Working Capital as % of expenses							**13.08%**

Building a better working world

Table 19 shows Working Capital Requirement for test year 2015 expenses based on 2013 historical information

Expense item description	Revenue Lag (days)	Inventory Lag (days)	Expense Lead (days)	Net lag (lead) days	Working capital factor	Expenses from financial statement	Working capital requirement
	A	B	C	D=A+B-C	E=G/F	F	G=F x D/365
Cost of Power	60.39		20.89	39.49	11%	102,012,056	11,037,588
OM&A - payroll & benefits	60.39		10.42	49.97	14%	5,667,950	775,975
OM&A - supplier & other	60.39	50.88	17.75	93.51	26%	5,389,853	1,380,793
OM&A - Municipal Taxes	60.39		-25.00	85.39	23%	152,292	35,626
Interest on Long Term Debts	60.39		6.00	54.39	15%	1,910,000	284,594
Payment in lieu of Charges	60.39		12.50	47.89	13%	240,000	31,487
Debt Retirement Charges	60.39		30.50	29.89	8%	7,532,929	616,788
Sub-Total						122,905,080	14,162,851
HST						1,446,444	-126,495
Total (Including HST)						124,351,524	14,036,356
Working Capital as % of expenses							**12.40%**

8.0 Conclusion

For the purposes of the working capital allowance for the rate application of the Test Years 2015 to 2019, OPUC is proposing to use an average Allowance for Working Capital from 2012 and 2013, adjusted for HST. The Allowance of Working Capital is applied to forecast cost of power, OM&A, and other budgeted expenses for 2014 to determine the working capital requirement to be included in the 2014 bridge year and the 2015 – 2019 Test Years.

Table 20 shows Working Capital Allowance for Test Year

Years for WC allowance	2012	2013	Average WC for 2014
Working Capital as a % of expenses	13.08%	12.40%	**12.74%**

Table 21 shows Working Capital requirements for 2014 budget, compared with 2012 and 2013 amounts

Working capital allowance based on WC requirements as % of total expenses	2012	2013	Budget 2014
Power Supply expenses	$96,181,988	$102,012,056	$105,428,711
Net OM&A expenses (as per financial statement)	$11,240,450	$11,210,095	$11,245,605
Total Expenses for WC	$107,422,438	$113,222,151	$116,674,316
Working Capital (% of Power and OM&A)	13.08%	12.40%	**12.74%**
Total Amount of WC	**14,050,333**	**14,036,356**	**$14,862,381**

Budget 2014 Power Supply and OM&A expenses are from OPUC 2014 Budget income statement.

OSHAWA PUC Networks Inc.
A Lifetime of Power.

Distribution System Plan

January 29, 2015

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I. DISTRIBUTION SYSTEM PLAN OVERVIEW

1. INTRODUCTION

Oshawa PUC Networks Inc. (OPUCN) owns and operates an electricity distribution network that serves 54,660 customers over 149 square kilometres in the City of Oshawa and the Region of Durham. This is OPUCN's first consolidated Distribution System Plan (DS Plan) prepared in accordance with Chapter 5 of the Ontario Energy Board's (OEB or Board) *Filing Requirements for Electricity Distribution Rate Applications*, July 17, 2013 revision (Guidelines).

This DS Plan covers OPUCN's ***capital investment plan*** for the Bridge Year 2014 and the Test Years 2015 through 2019, and provides historical actual capital expenditures for the years 2010 through 2013 and the Bridge Year (2014). As this is OPUCN's first DS Plan, there is no information to provide on OPUCN's performance in relation to achievement of the operational or other objectives targeted by investments, the costs for which were approved through review and acceptance by the Board of previous consolidated plans. Instead, this DS Plan reviews OPUCN's investment history and documents the impacts of this historical investment program on the current and planned asset management and investment strategy.

This DS Plan also documents OPUCN's ***asset management program***. The approach that OPUCN uses to collect, tabulate and assess information on physical assets, current and future system operating conditions, business needs and customer feedback is described. How this information is used to plan, prioritize and optimize capital expenditures is explained.

This DS Plan further illustrates how OPUCN has met the OEB's expectations for electricity distributor planning, as those expectations have been articulated in the

Board's *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012 (RRFE)[1]. In particular, this DS Plan addresses:

a) ***Regional system planning considerations.*** As detailed in Part II, Section 3, as part of the Regional Planning activities for the GTA East Region OPUCN is engaged with Hydro One Networks Inc. (HONI) Transmission and Distribution, the Ontario Power Authority (OPA) and other affected distributors in addressing anticipated transmission and capacity constraints in the region and developing both interim and longer term solutions.

b) ***Public policy goals.*** As detailed in Part II, Section 4, OPUCN does not anticipate any renewable generation connection requests which would require capital investments during the plan period.

   As detailed in Part VI, Section 2.d., OPUCN engaged a third party consultant (UtiliWorks) to assess OPUCN's present grid status and develop a *Smart Grid Roadmap and Financial Analysis*. OPUCN believes that adopting grid modernization through distribution automation and development of an intelligent communication network will provide value to the Oshawa community.

c) ***Delivery of "value for money".*** OPUCN's System Renewal and System Service capital programs ensure the ability to reliably serve both present and future customers (as detailed in Part VI, Sections 3.b and 3.c.)

   OPUCN's "smarter grid" and Outage Management System (OMS) proposals respond directly to customer preferences for reliability and power quality as revealed through OPUCN's customer engagement activities (as detailed in Part II, Section 1).

   This DS Plan reflects OPUCN's continued commitment to operational effectiveness, productivity improvement and cost performance. The cost forecasts for the plan period, when considered in light of OPUCN's historical and current financial performance relative to its peers (see Part III, Section 4), and against the annual average 3% customer connection and peak load growth forecasts, indicate that despite demanding capital investment requirements, OPUCN's plan will continue to deliver and enhance system reliability and quality of service while maintaining top quartile financial performance.

d) ***Benchmarking for reasonableness.*** OPUCN's DS Plan is informed and supported by four external studies:

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[1] RRFE, pages 1-2.

i. METSCO Energy Solutions (METSCO) has provided an *Asset Condition Assessment Report and Asset Management Plan* which documents METSCO's review of the status of OPUCN's distribution infrastructure and identification of critical and high priority asset investment requirements. METSCO's report has formed the basis for OPUCN's System Renewal capital investment program and the prioritization of its component projects.

ii. NBM Engineering Inc. (NBM) has provided an independent view on the expected costs of OPUCN's System Renewal and System Service projects, as a benchmark against which the reasonableness of OPUCN's own Capital Investment Program cost forecasts can be assessed.

iii. Utility*PULSE* has carried out, and provided reports on, customer surveys commissioned by OPUCN to establish customer satisfaction and customer priorities regarding OPUCN's distribution services. The feedback obtained through this customer engagement has informed OPUCN's proposal to invest in a "smarter" grid, and the proposed Outage Management System (OMS) and related system enhancements.

iv. The UtiliWorks *Smart Grid Roadmap and Financial Analysis* referred to above has provided an expert guide informing OPUCN's measured plan for a "smarter" grid to enhance customer value and move OPUCN towards a "smarter" and more operationally efficient and effective future.

In addition to the foregoing external studies, OPUCN commissioned Pacific Economics Group (PEG) to provide a Total Cost Benchmarking review of OPUCN's Custom IR Plan proposed revenue requirement forecasts. PEG's report indicates that considering both OPUCN's capital and O&M cost forecasts for the plan period 2015 through 2019, OPUCN remains among the most cost efficient electricity distributors in the province.

2. KEY ELEMENTS & DRIVERS

a. *Historical Overview*

Table 1 reflects OPUCN's historic and forecast net[2] capital expenditures over the period 2010 to 2019.

Table 1 - Historic and Forecast Net Capital Expenditures

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NET Capital (millions)	**$4.7**	**$16.5**	**$11.1**	**$10.7**	**$11.7**	**$13.5**	**$11.6**	**$12.4**	**$12.5**	**$10.8**

From 2008 through 2010 OPUCN's net annual capital spending averaged approximately $6 million.[3] Over this three year period investments focused mainly on third party relocation requests, customer service connections, and overhead and underground plant rebuilds.

From 2011 through 2013, OPUCN's net annual capital spending increased to an average of approximately $10.6 million (not including smart meter implementation of approximately $6.5 million which was accounted for in 2011). The incremental annual average spending of approximately $4.6 million relative to previous years was driven primarily by System Renewal requirements. Overall capital spending over this period included:

- Four Station rebuilds involving the replacement of eight power transformers, underground and overhead infrastructure replacements, and relay and breaker replacements (~ $7M);
- Four underground vault rebuilds with associated equipment upgrades (~$1.5M);

[2] After customer contributions toward connection costs and third party contributions for OPUCN plant relocation.
[3] Net capital expenditure in 2008 was $6.7 million and in 2009 was $6.3 million.

- Overhead and underground plant rearrangements to facilitate load transfers and system balancing, as initial collaborative solutions with Hydro One Transmission to start addressing upcoming transmission station capacity limitations (~$1.6M); and

- General Plant upgrades to fleet, facilities, Geographical Information Systems (GIS), operational data storage (ODS) and IT server room and disaster recovery (DR) sites (~$3.6M).

In 2014, OPUCN forecasts a net total expenditure of approximately $11.7 million, approximately $1.1 million higher than the annual average from 2011 through 2013.

Table 2 - 2014 Net Capital Expenditures

Year	System Access	System Service	System Renewal	General Plant	NET Total
	$'000	$'000	$'000	$'000	$'000
2014	**2,307**	**2,830**	**5,958**	**634**	**11,729**

2014 investments included:

- System Renewal: Overhead and underground rebuilds and station power transformer replacement.

- System Service:

    - To address load growth in Oshawa and resulting capacity constraints at both Wilson and Thornton transmission stations (TS) – overhead extension and upgrades of primary feeders to allow switching flexibility and system load balancing between Wilson and Thornton TS (~$1.8 million).

    - Underground downtown vault automation to enhance system reliability and resiliency (a "smart grid" project of ~$1 million).

In summary, from 2011 through 2014, significant investments were driven primarily by system renewal investments to improve system reliability and mitigate customer outage impacts, through the required replacement of end-of-useful life or high failure risk assets, resulting from an aged infrastructure.

A secondary but significant driver of recent capital investments was System Service, in initial preparation to address upcoming transmission station capacity limitations given the forecast load growth in Oshawa.

b. *Key Drivers of OPUCN's 2015-2019 Capital Investment Plan*

OPUCN's net total capital expenditure over the planning period 2015 through 2019 is forecasted to be $60.8 million, which is an average annual spend of $12.2 million. While maintaining the capital spending levels experienced in recent years, the plan period spending shifts from System Renewal to System Access and System Service in order to address Oshawa's robust growth forecasts.

In particular, drivers for capital expenditures over the planning period include:

- Customer connections growing by approximately 15% in the five year period.
- Residential and commercial peak demand (kW) growth of approximately 3% annually, on average.
- Grid modernization to enhance value provided to the customer including enhanced system reliability and resilience. This will involve distribution system automation, intelligent devices and software applications to mitigate customer impact of system outages, reduce system restoration time and improve customer satisfaction.

(i) Customer Connections Growth

Based on its consultations with the City of Oshawa's Economic Development/Planning Group and Durham Region's Planning & Development Group, OPUCN expects its customer base to increase at a significantly faster rate over the next five years than it has historically. OPUCN's consultations confirm, on average, a projected annual customer connection growth rate of approximately 3%, compared to annual customer growth from 2010 through 2014 of approximately 1% or less. The projected rate of customer connection growth is supported by the increase in issued building permits and evidence of several major residential and commercial real estate developments currently in planning stages.

The City of Oshawa published a 2012 total building permit value of approximately $310 million. In 2013, 1,304 building permits were issued with a total value of approximately $369 million. The issued permit value for January through September 2014 is approximately $410 million.

As of December 2013, there were over 66,000 customer connections. Based on the current development information provided by the City of Oshawa, OPUCN has projected customer connections growth to over 78,000 by 2019.

Table 3 - Oshawa's Customer Connections Growth: 2009-2019

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Average Annual Customer Connection Count									
2008 Board Approved	47,243	3,845	522	2	9	11,650	77	305	63,653
2012 Board Approved	49,920	3,961	518	1	10	12,762	22	313	67,507
2003	43,320	3,689	559	3	5	10,059	35	292	57,961
2004	43,980	3,627	530	3	6	10,262	30	294	58,731
2005	44,599	3,662	522	2	8	10,499	30	295	59,615
2006	45,439	3,741	525	2	9	10,831	29	298	60,873
2007	46,320	3,749	523	2	9	11,281	27	301	62,211
2008	47,058	3,794	534	3	9	11,622	26	301	63,345
2009	47,603	3,860	525	2	10	11,801	26	303	64,128
2010	48,115	3,929	513	1	10	11,996	25	307	64,894
2011	48,651	3,889	521	1	10	12,128	24	303	65,525
2012	49,021	3,851	512	1	11	12,213	24	296	65,927
2013	49,511	3,902	500	1	11	12,328	24	295	66,572
2014 Bridge Year	50,177	3,924	500	1	11	12,581	23	295	67,512
2015 Test Year	51,682	4,042	515	1	11	12,958	22	296	69,527
2016 Test Year	53,233	4,163	531	1	12	13,347	22	296	71,603
2017 Test Year	54,830	4,288	546	1	12	13,747	21	296	73,741
2018 Test Year	56,474	4,416	563	1	12	14,160	20	297	75,943
2019 Test Year	58,169	4,549	580	1	13	14,585	19	297	78,212

Supporting projections for accelerated customer load growth is the ongoing Highway 407 East Extension Project. Phase 1 of the 407 extension is expected to be completed in 2015 and extends from Brock Road in Pickering to Harmony Road in Oshawa. Phase 2 is proposed from Harmony Road to the 115/35 Highway and is expected to be completed in 2019/2020.

The demonstrated increase in large residential subdivisions and commercial developments, especially along the extended 407 corridor, confirms the need for OPUCN to plan for ongoing and future customer load requirements.

For example, in North Oshawa, *Kedron Part II* is the next major residential community and is expected to have Phase 1 in service in 2016 with full completion over a 10 year period. The entire development spans approximately 1,151 acres and projects a planned population of around 22,000 people with a mix of residential, commercial and institutional uses. Anticipated total load is 15 MW.

Similarly, RioCan has received approval for a 1.3 million square foot commercial development in North Oshawa, and its construction is underway with full completion by 2020. The first phase in-service date is scheduled to coincide with the 407 opening in 2015, and the anticipated total load for the completed development is 3 MW.

In addition, Oshawa Center shopping Mall in Downtown/Midtown Oshawa started its $230 million expansion and redevelopment in 2013, with a projected load of 1.5 MW upon expected completion in 2016.

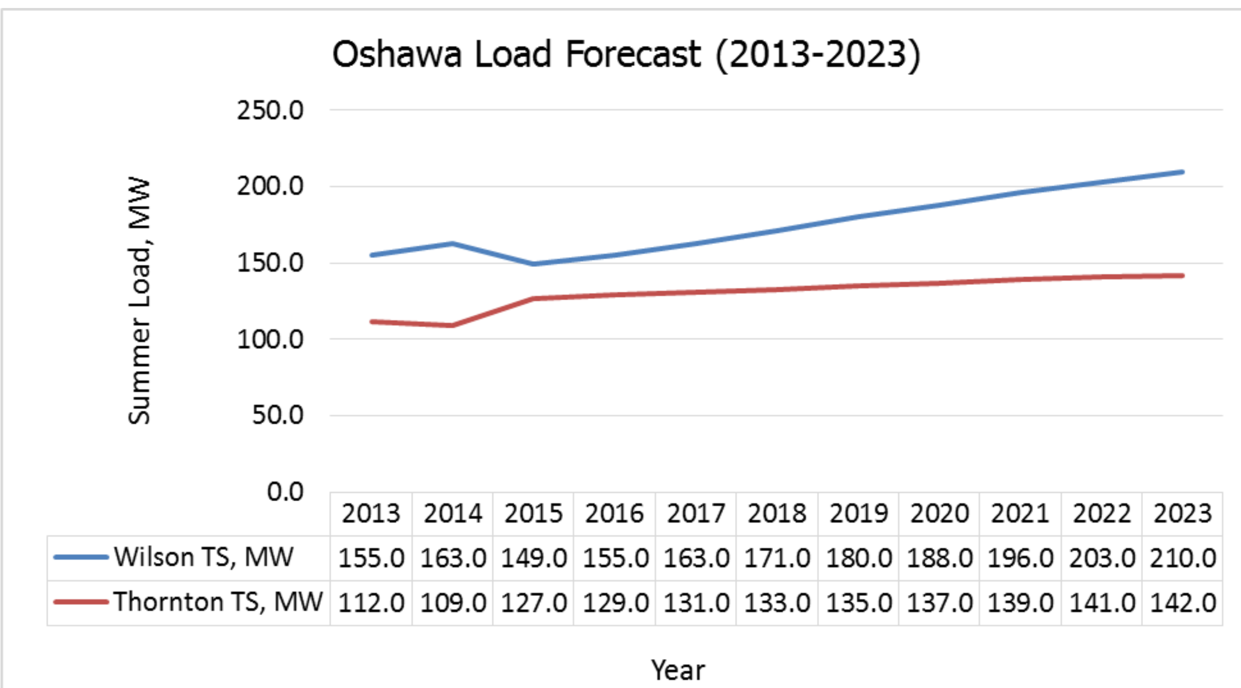
(ii) Demand Load (kW) Increase

For system planning purposes, sufficient distribution system capacity must be planned to meet peak load requirements. Overall, Oshawa's peak load is projected to increase from 267 MW in 2013 to 315 MW by 2019. This is an average of 3% annually over the five year planning period. Table 4 and Figure 1 present OPUCN's Peak Load Forecast which was submitted to, and accepted by, HONI as part of the regional planning initiative for the GTA East Region.

Table 4 Regional Planning - Extract from HONI's Needs Screening Load Forecast

Customer	Transformer Station	DESN ID	Sum of 2013	Sum of 2014	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	Sum of 2020	Sum of 2021	Sum of 2022	Sum of 2023
⊟Oshawa PUC Networks Inc.	⊟Thornton TS	T3/T4	112.0	109.0	127.0	129.0	131.0	133.0	135.0	137.0	139.0	141.0	142.0
	Thornton TS Total		112.0	109.0	127.0	129.0	131.0	133.0	135.0	137.0	139.0	141.0	142.0
	⊟Wilson TS	T1/T2	137.0	144.0	132.0	137.0	144.0	151.0	159.0	166.0	173.0	179.0	185.0
		T3/T4	18.0	19.0	17.0	18.0	19.0	20.0	21.0	22.0	23.0	24.0	25.0
	Wilson TS Total		155.0	163.0	149.0	155.0	163.0	171.0	180.0	188.0	196.0	203.0	210.0
Oshawa PUC Networks Inc. Total			267.0	272.0	276.0	284.0	294.0	304.0	315.0	325.0	335.0	344.0	352.0

Figure 1: TS Loading Forecasts



(iii) Grid modernization

The third key driver of OPUCN's DS Plan is the program to modernize OPUCN's distribution grid to improve system reliability and resiliency. Given today's technology, customers are now expecting their electrical utility to minimize service disruptions and better manage outage duration, impact and communications. As OPUCN develops its distribution plant, OPUCN plans to increase the installation of automated and self-healing devices and equipment to allow remote automated switching and fault isolation to reduce restoration time and outage impact to customers.

Advanced technology with intelligent devices and management systems will enable OPUCN to operate a "smarter grid" that will have better visibility and operational flexibility. In addition to minimizing outage impacts, OPUCN's future system will identify ways to improve line losses and manage peak consumption to reduce transmission charges, resulting in lower customer electricity costs.

c. *Key Elements of 2015-2019 DS Plan*

In response to the drivers summarized above, the key elements of OPUCN's 2015 – 2019 DS Plan are described below, in reference to the OEB Guidelines investment categories:

(i) System Access

OPUCN's planned System Access capital projects are nondiscretionary, and primarily driven by:

- Customer service requests (i.e. expansions and connections) (~$2.8 M)
- Third party infrastructure developments or road reconstruction (407, Region and City) necessitating distribution asset relocations (~$7.7 M)
- Mandated revenue metering and service obligations (MIST metering, Smart Grid initiatives) (~$3.4 M)

The Net total system access capital expenditure forecast over the five year planning period is approximately $14 million or 23% of the net overall total capital expenditure for the period of $60.8 million.

Table 5 - Summary of System Access forecast expenditures 2014 – 2019

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access	NET EXPANSIONS & CONNECTIONS	*650*	*545*	*560*	*560*	*575*	*585*	2,825
	Total NET 3rd Party Infrastructure Requests - plant relocation cost (407, Region, City)	982	2,804	1,450	1,150	1,150	1,150	7,704
	Total Metering	280	625	630	765	615	615	3,250
	Long Term load transfers	395						0
	Ministry of Energy approved Micro Grid Project	0	110	45				155
	NET TOTAL SYSTEM ACCESS	2,307	4,084	2,685	2,475	2,340	2,350	13,934

Details of OPUCN's System Access capital investment program are provided in Part VI, Section 3.

(ii) System Renewal

Capital projects included in this investment category are:

- Guided by asset condition assessments conducted on a regular basis; and
- Involve replacing and/or refurbishing system assets at the end of their useful lives, at high risk of failure or otherwise exhibiting substandard performance.

The total forecast capital expenditure over the five year planning period in this category is approximately $24 million or 39% of the overall total DS Plan investments.

Table 6 - Summary of System Renewal Forecast Expenditures 2014-2019

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total 2015-2019**
		$'000	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
System Renewal	OH REBUILDS	2,663	2,410	2,455	2,055	2,510	2,117	**11,547**
	UG REBUILDS	1,450	1,133	1,007	1,087	921	904	**5,052**
	STATIONS REBUILDS	1,015	510	640	500	500	1,000	**3,150**
	Total Planned Plant Rebuilds	**5,128**	**4,053**	**4,102**	**3,642**	**3,931**	**4,021**	**19,749**
	Reactive/emergency Plant Replacement	830	830	830	830	830	830	**4,150**
	TOTAL SYSTEM RENEWAL (OH, UG and Stations rebuilds)	**5,958**	**4,883**	**4,932**	**4,472**	**4,761**	**4,851**	**23,899**

System renewal investments involve the replacement or refurbishment of system assets identified as being at or near the end of their useful service life. These rebuilds are required to allow OPUCN to maintain electricity services to its customers at an optimal level of reliability. Planned (proactive) System Renewal is guided by the results of OPUCN's Asset Condition Assessment and related Asset Management Plan detailed in Part I, Section 4 below.

Planned capital projects in this category involve overhead plant rebuilds, underground plant rebuilds and station rebuilds. As illustrated through OPUCN's reliability performance indices (detailed in Part III, Section 2), recent investments in this category have improved OPUCN's operational performance.

Investments in this category also include reactive expenditures for replacement of assets that fail in-service.

(iii) System Service

Projects in this investment category are required to:

- Alleviate transmission and/or distribution capacity constraints due to load growth; and/or
- Enhance system operation, efficiency and resiliency (e.g. distribution automation, protection and control upgrades).

The total forecast capital expenditure over the five year planning period in this category is approximately $18 million or 30% of the overall total DS Plan investments of $60.8 million.

Table 7 - Summary of System Service Forecast Expenditures 2014–2019

		Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS		2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Services	Total Contributions to HONI for Transmission Capacity		1,500	1,500	1,000	1,000	1,500	6,500
	Total MS9 Substation and Overhead rebuilds for Distribution Capacity	1,930	750	1,000	3,250	3,000	1,000	9,000
	Total Grid Modernization projects	900	618	330	420	645	550	2,563
	TOTAL SYSTEM SERVICES	2,830	2,868	2,830	4,670	4,645	3,050	18,063

Investments included in the System Service category include estimated contributions to HONI to implement solutions to address transmission capacity constraints and investment in a new OPUCN municipal substation to service customer growth in the north area of Oshawa.

System Service expenditures also include investments in grid modernization that will enhance customer value including enhanced system reliability and resilience. This will involve distribution automation, intelligent devices and software applications to mitigate customer impact of system outages, reduce system restoration time and improve customer communication.

(iv) General Plant

Investments in this category include non-system physical plant upgrades or replacements that provide day to day business and operational support.

The total capital expenditure included in the General Plant category for the five year planning period is approximately $4.9 million, or 8% of the overall DS Plan expenditures.

Table 8 - Summary of General Plant Forecast Expenditures 2014-2019

		Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS		2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
General Plant	Fleet	155	420	415	440	190	170	1,635
	Total Facilities Leasehold Improvements	104	225	50	50	50	50	425
	Major Tools and Equipment	40	50	50	50	50	50	250
	Total Operational Capital Projects (OMS, MWF, GIS, MAS, ODS, CIS, IVR Enhancements)	245	850	535	135	160	160	1,840
	Total Office IT Capital Expenditure (software and hardware)	90	130	130	80	280	80	700
	TOTAL GENERAL PLANT	634	1,675	1,180	755	730	510	4,850

Investments in the General Plant category are driven by operational and business needs to achieve a safe work place, enhance employee work environments and satisfaction, increase efficiencies and productivity, and enhance customer service and value.

Key OPUCN projects included in this investment category are:

- Outage Management System (fully integrated with SCADA, GIS, AMI/MAS, CIS, IVR, and complimentary to OPUCN's "smarter grid" investments)
- Mobile Work Force System
- Operational Data Storage (ODS) replacement/enhancements (as existing ODS is not equipped to meet future operational business needs)
- IT Server Infrastructure replacement due to end of life and vendor no longer providing maintenance
- Facilities or leasehold improvements within existing facilities to accommodate additional resources
- Fleet replacements for vehicles that are approaching end of useful life and undergo frequent or high maintenance, or become a high risk when in use.

(v) Proposed Renewable Energy Generation (REG) Investments

OPUCN is not presently planning any capital expansion or enhancement investments related to REG connections (FIT or Micro-FIT) over the planning period 2015-2019. OPUCN submitted its Renewable Energy Generation Investments Plan to the OPA and the OPA has acknowledged in its Letter of Comment (see Exhibit 2, Tab B, Schedule 1) that OPUCN's plan is consistent with the OPA's information regarding REG applications to date.

(vi) System O&M Cost

Table 9: System O&M Costs

	Bridge Year	FORECAST PERIOD (Plan)					
CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System O&M	2,337	2,634	2,860	2,999	3,015	2,878	14,386

The Board's Guidelines require that the overall quantum of investments included in a DS Plan be supported by, *inter alia*, a forecast impact of system investment on O&M costs.[4]

With a few exceptions, the historical and future investments detailed in this DS Plan are non-discretionary, and thus are not undertaken with reference to O&M costs or benefits. This is the case for most of the planned System Renewal (i.e. end of useful life or high failure risk assets), System Access (i.e. customer connections or plant relocation projects), and General Plant (see investments listed on page 11). These projects address needs which cannot be economically met or deferred by increases in O&M costs.

[4] Guidelines, page 19.

For the sake of completeness, OPUCN has provided in this DS Plan its historical, Bridge Year and plan period System O&M costs. These costs are, however, independent of, and not directly impacted up or down by, investments contemplated in this DS Plan.

OPUCN's proposed Grid Modernization projects are expected to render operation of the future distribution system more efficient, and to avoid or shorten customer interruptions due to system outages. Investments in prepaid and remote disconnect/reconnect metering technologies are expected to reduce bad debt expense, collection costs and personnel time related to disconnection/reconnection activities. Investment in an Outage Management System (OMS) and integration of this system with OPUCN's other grid and operational management systems responds to key feedback from OPUCN's customer survey through investment that will result in faster and more efficient service restorations, reduced outage impacts, and improved customer communication through provision of timely updates on outages. These "discretionary" initiatives are expected to avoid future O&M costs. OPUCN has not precisely quantified such avoided future costs. OPUCN's forecast O&M increases during the plan period have been constrained on an inflation adjusted basis (assuming 2% inflation), to less than 12% in the face of forecast customer connections and peak demand growth of 15% over the plan period. As detailed elsewhere in this DS Plan (see Part III, Section 4.), OPUCN has been, and plans to continue to be, among the most cost efficient electricity distributors in the province. The foregoing "discretionary" projects are proposed in order to allow OPUCN to maintain this superior level of efficiency.

3. SOURCES AND VINTAGE OF INFORMATION USED

The following sources of information were key in evaluating OPUCN's future service requirements and formulation of its Capital Investment Plan:

System Access – customer growth and load forecasts

- City of Oshawa's Economic Development Plans

  - Most recent 2014 annual community and development reports prepared by City of Oshawa
  - 2014 Annual Realtor Breakfast and Economic and Development Seminar with developers, City representatives, financial institutions, builders and OPUCN (hosted by City of Oshawa)
  - On-going planning discussions with City staff on current and proposed development plans
- City of Oshawa Planning Group
  - regular updates on building permits issued,
  - status of new and existing development, residential and commercial services
- Quarterly Building Industry and Land Development (BILD) Association meetings with City's planning representatives, developers, builders and OPUCN
- Ongoing developer and customer communications and service requests
- Regular communication with key customers, for example: UOIT, Lakeridge Hospital, Oshawa Center, COSTCO, Metrolinx/GO Transit

System Access - third party infrastructure developments – OPUCN plant relocations

- Eastern Construction General Partners (ECGP) 407 plans and construction schedules
- Durham Region five-ten year Roadway Construction Plans – current year and tentative five year construction plans - regular updates
- City of Oshawa five year Roadway Construction Plans – current year and tentative five year construction plans - regular updates

System Renewal – identification of asset replacements and rebuilds

- Recent (2013) Asset Condition Assessment and Asset Management Plan conducted by third party consultant (METSCO)
- OPUCN Maintenance & Operational inspection records, system outage and incident reports

- GIS asset registry to reference age, type, location, quantity and replacement or maintenance history of assets

System Service – transmission and distribution capacity and grid automation (Smart Grid) investments

- System data and load monitoring for both transmission and distribution (ICCP and SCADA systems) – existing data updated with load projections
- OPUCN peak load forecast regularly updated and annually reviewed by HONI for Regional Planning Capacity investments
- Smart Grid Roadmap and Financial Analysis report prepared by third party consultant (UtiliWorks) – February 2014
- Industry practices related to distribution automation initiatives and available working technology
- Communication with and feedback from other LDCs on their grid automation investments

4. ASPECTS OF PLAN CONTINGENT ON FUTURE EVENTS

System Access - Customer connections and developments/expansions including metering requirements (~$6 million)

OPUCN forecasts a growth rate in service connections of approximately 15% over the five year period. As a result, OPUCN's DS Plan includes significant net capital investments of approximately $6 million related to customer connections and expansions, including metering requirements. These investments and their timing are contingent on the advancement of the developments anticipated by the planning authorities consulted and the reality of homes and commercial units being constructed and sold.

System Access – Durham Region and City of Oshawa requests for plant relocations (~$6.5 million)

OPUCN receives requests from the Region of Durham and the City of Oshawa, for OPUCN distribution plant relocations to accommodate annual roadway reconstruction. Historically, although high level plans are identified, actual implementation does not materialize precisely as planned. This type of expenditure is nondiscretionary and is driven by the Region and the City schedules. OPUCN can only include in its DS Plan the locations and high level designs identified by these regional and municipal agencies. Actual annual expenditures and contributions will be dependent on final designs and work schedules.

System Service - Contributions to HONI for transmission capacity (~$6.5 million budgeted, pending better information from HONI)

OPUCN has included $6.5 million in its Capital Investment Plan for contributions to HONI to address transmission capacity constraints in supply to the City of Oshawa. This figure was initially developed in consultation with HONI, in response to identification of a solution involving the addition of two new feeder breaker positions at each of the Wilson and Thornton transmission stations. The discussions giving rise to this estimate predated the formal Regional Planning initiative now in process.

Since commencement of a formal Regional Planning Process for the GTA East Region mid-way through 2014, and as set out in HONI's most recent updated regional planning status letter (dated December 12, 2014, see Exhibit 2, Tab B, Schedule 2), HONI, as Lead Transmitter in that process has indicated that: i) in light of the updated total peak load forecast for the GTA East Region, the option of adding two new feeder breaker positions at each of the Wilson and Thornton transmission stations is no longer deemed to be a viable permanent solution, and a new 230/44 KV transmission station will be required, to be in service in 2018/2019; and ii) the local planning study team is also reviewing interim options to ensure sufficient supply capacity to the region pending the now anticipated transmission station coming into service in 2018/2019.

HONI has been unable to date to confirm OPUCN's contribution for the permanent (transmission station) capacity constraint relief solution, but has indicated that such contribution "could be in the range of $10 million to $12 million". [5] Additional contribution for an interim solution is not yet quantified. In the absence of better information, OPUCN has retained its initial $6.5 million estimate in this DS Plan for transmission investment contributions to HONI. HONI has indicated that it expects the local planning to be complete in Q1, 2015, at which time this estimate can be updated.

System Service – Distribution Capacity - MS9 new municipal substation and associated feeder expansion (~$9 million)

OPUCN has identified the need to construct a new municipal substation (MS9) to have distribution capacity to service its future customers. Ongoing growth in the north area of Oshawa reinforces the need to build this substation sooner rather later as the lead time to build these distribution facilities is approximately four to five years. Included in this DS Plan is the forecast capital investment for the substation of $7 million, and the cost of primary feeder extension from the station which is forecast to be an additional $2 million.

Uncertainty regarding the outcome of the environmental assessment required on the property, including any potential remediation, and with potential customer objections or concerns over the new substation, indicates a risk of delay beyond the five year planning period. In addition, depending on the remedies required, the actual expenditure may be more than currently estimated.

[5] If a new transmission station is the permanent capacity constraint relief solution, then in addition to contribution towards the cost of a new transmission station OPUCN would have to make additional distribution system investments. OPUCN has preliminarily identified the potential need for approximately 5 km of 44 kV overhead primary distribution lines extending from the proposed transmission station to OPUCN's new proposed distribution station (MS9), at an additional, distribution system, investment of approximately $3.5 million in the 2018/2019 time frame.

II. COORDINATED PLANNING IN CONSULTATION WITH THIRD PARTIES

This DS Plan has been informed by engagement with all major stakeholders:

- Customers (residential, commercial and industrial);
- Developers and builders;
- City of Oshawa and the Region of Durham;
- HONI Transmission, HONI Distribution, the Ontario Independent Electricity System Operator (IESO) and other distributors (Whitby Hydro and Veridian Connections); and
- the Ontario Power Authority (OPA).

1. CUSTOMER ENGAGEMENT

OPUCN conducts customer surveys approximately every two years. In May 2013, OPUCN retained the services of an external consultant, Utility*PULSE,* to conduct a customer survey. Utility*PULSE* is able to not only conduct surveys of OPUCN customers, but also to benchmark the results of those surveys against customer feedback regarding other Ontario and Canadian utilities.

OPUCN commissioned customer survey and results benchmarking reports from Utility*PULSE* for both its large customers (December 2013) and for its general service customers (June 2014). Copies of both reports are filed along with this DS Plan (see Exhibit 1, Tab D, Schedule 1 and Exhibit 1, Tab D, Schedule 2). These reports indicate that OPUCN is equal or better than the average LDC in Ontario and nationally in the eyes of its customers. Overall, 91% of OPUCN's customers are very or fairly satisfied with OPUCN. In terms of priority investments, 86% support the upgrading and maintaining of plant to improve reliability, and 80% and 75% support investment to reduce the restoration time during outages and to reduce the number of outages, respectively. These results support OPUCN's focus on System Renewal investments, Smart Grid initiatives and an integrated OMS.

OPUCN posts on its website a listing of its capital investment projects for the coming year. OPUCN has posted its capital projects for 2014 and in January 2015, will post its 2015 program. This allows OPUCN customers to review the proposed projects and submit their concerns or questions to OPUCN. Any customer feedback or concerns are reviewed and responses provided accordingly.

OPUCN also provides advance notices to customers advising them of upcoming overhead or underground plant rebuilds in their area or neighbourhood, including any planned outages. Any questions or concerns (for example location of the proposed poles or pad-mount type transformers) are normally resolved directly with the customer.

OPUCN plans to hold an open house in 2015 regarding its new substation (MS9) planned for construction in 2016, to engage its customers and share the high level details of this new substation plan. OPUCN will receive customer feedback and address any concerns to the best of its abilities.

OPUCN continues to meet with its major customers (e.g. University of Ontario Institute of Technology (UOIT), Lakeridge Health Centre, Oshawa Center) and key developers (e.g. The Metrontario Group/Tribute Homes, The Rice Group/COSTCO; Great Gulf Development), for ongoing updates and service related consultation on their project plans and future developments.

2. REGIONAL AND MUNICIPAL GOVERNMENTS

To assist OPUCN with its asset management and system capacity planning, OPUCN maintains regular discussions with the City of Oshawa’s Economic Development and Planning Group and the Region’s Planning & Development Department. OPUCN tracks the proposed construction schedule and phases of planned developments, including associated loads, to determine capacity requirements and identify any capacity issues.

OPUCN also monitors Region and City work schedules in order to, where possible, co-ordinate its own work and project completion schedules with those of the Region and

City, all in order to avoid conflicts and unnecessary inconvenience to customers, especially businesses in the downtown area, and to minimize costs where possible.

3. HYDRO ONE NETWORKS INC. AND OTHER DISTRIBUTORS – REGIONAL PLANNING INITIATIVE

OPUCN is engaged with HONI (Transmission and Distribution), the OPA and other affected distributors as part of the Regional Planning activities for the GTA East Region. A "Needs Screening" recently completed by the GTA East Region Study Team recommends a Regional Infrastructure Planning (RIP) process under HONI's lead (as opposed to an Integrated Regional Resource Planning (IRRP) Process led by OPA) to address transmission capacity issues at Wilson TS and Thornton TS.

The outcome of the Local Planning (RIP) meetings are expected in February 2015. The impact of these local and regional planning initiatives to date has been summarized elsewhere in this DS Plan (see Part VI, Section 3.c.(ii)).

4. ONTARIO POWER AUTHORITY (OPA) RENEWABLE ENERGY GENERATION INVESTMENTS

OPUCN submitted its REG Investment Plan to the OPA and received the OPA Letter of Comment (see Exhibit 2, Tab B, Schedule 1). There are no renewable energy generation (REG) connection investments included in this DS Plan. The OPA has acknowledged that this is consistent with the OPA's information regarding REG applications to date.

III. PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

This section of the DS Plan addresses; i) measurement and evaluation of the quality OPUCN's planning and plan implementation processes; and ii) OPUCN system performance trends over the historical period of 2009 through 2014 and how consideration of those trends has informed this DS Plan.

1. PLANNING & DS PLAN IMPLEMENTATION PERFORMANCE

OPUCN has the following controls in place to manage the implementation of its DS Plan:

- Capital program completion is an OPUCN corporate metric. This metric is simply defined as project completion on time and on budget. This metric is reported on and reviewed at OPUCN's monthly Executive meetings. The reporting includes discussion of any risks and associated mitigation to facilitate timely program completion within forecasted year end capital expenditure.
- OPUCN's design and construction management team conducts regular review meetings of the current capital program to determine risks in project completion, any project scope changes and related project cost impacts.
- OPUCN conducts project variance analysis on completed projects where actual costs are greater than 10% of estimated costs. Reasons or lessons learned are applied to future projects to ensure better project estimates.
- OPUCN conducts risk analysis and mitigation to ensure that projects are on track. Any significant change in project scope that indicates a 10% or greater increase in the original project cost is reviewed by the VP Engineering & Operations with appropriate managers, to confirm reasons for the variance and explore alternative solutions. If the variance is justifiable, a variance cost sheet with an explanation of changes in project scope is submitted to the VP Engineering & Operations and the CEO for approval.
- Any new project that arises within the budget year that is not included in the original budget is assessed by the VP Engineering & Operations with the appropriate managers to review the need for the project to be completed in that year. If it is needed, the project with estimated cost is submitted to the CEO for approval.

- At monthly Board of Directors' meetings, a high level capital program status review is presented by the VP Engineering & Operations.
- The year-end capital program completion and expenditure is reviewed at the Capital Committee sub-committee of the Board of Directors. The review includes examination of project cost variances.

2. SYSTEM PERFORMANCE TRENDS AND DS PLAN RESPONSE

a. *Reliability Performance*

OPUCN utilizes the following key performance indicators to continuously monitor its system operations and service quality performance: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI).

- **System Average Interruption Duration Index**

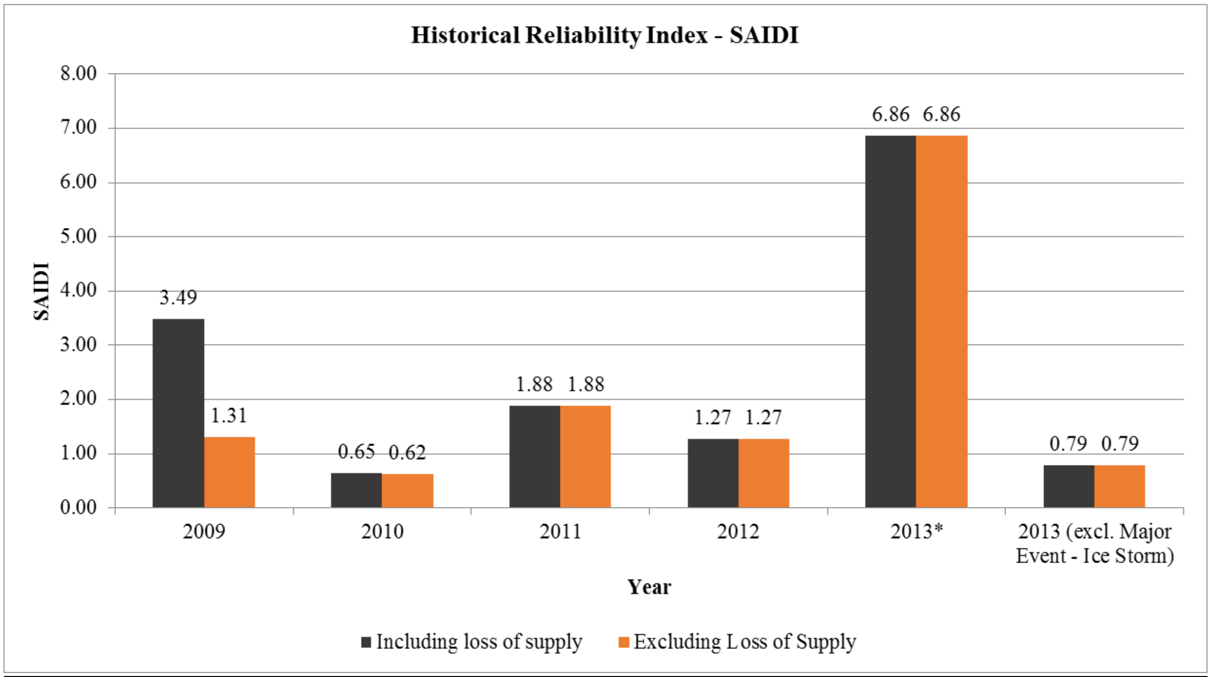
SAIDI is an index of system reliability that expresses the average interruption duration that a customer experiences in a reporting period (e.g. in a year). It is determined by dividing the total customer hours of interruptions by total number of customers served in the reporting period.

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Served}}$$

Loss of Supply is defined as loss of supply from HONI Transmission. OPUCN tracks SAIDI, including and excluding loss of supply, and submits quarterly reports of these statistics to the OEB.

Figure 1 shows the SAIDI performance for OPUCN during the past five years, 2009 to 2013 inclusively.

Figure 2: Historic SAIDI Performance



*Includes power outages due to the ice storm in December 2013 (an extreme weather event)

- **System Average Interruption Frequency Index**

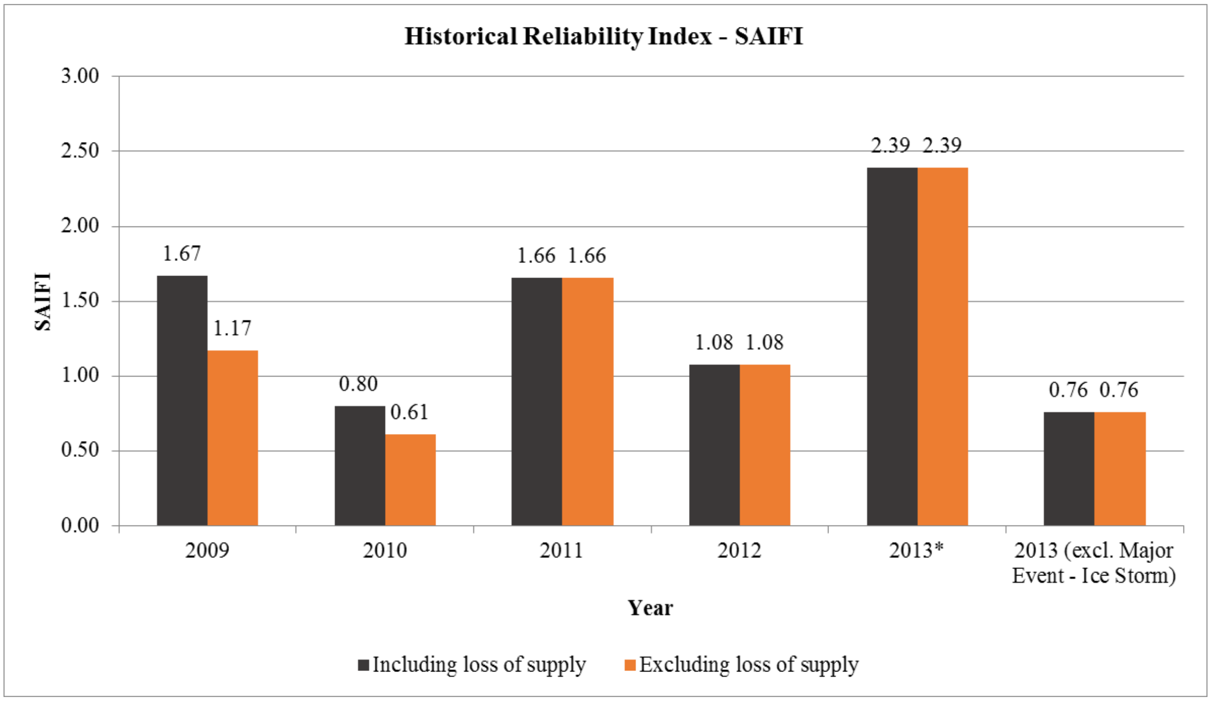
SAIFI is an index of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted. It is the average number of interruptions that a customer would experience, and is determined by dividing the total number of interruptions experienced by all customers, by the total number of customers served in the reporting period.

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

OPUCN tracks SAIFI, including and excluding loss of supply, and submits quarterly reports of these statistics to the OEB.

Figure 2 shows the SAIFI performance for OPUCN during the past five years, 2009 to 2013 inclusively.

Figure 3: Historic SAIFI Performance



*Includes power outages due to the ice storm in December 2013 (an extreme weather event)

- **Customer Average Interruption Duration Index**

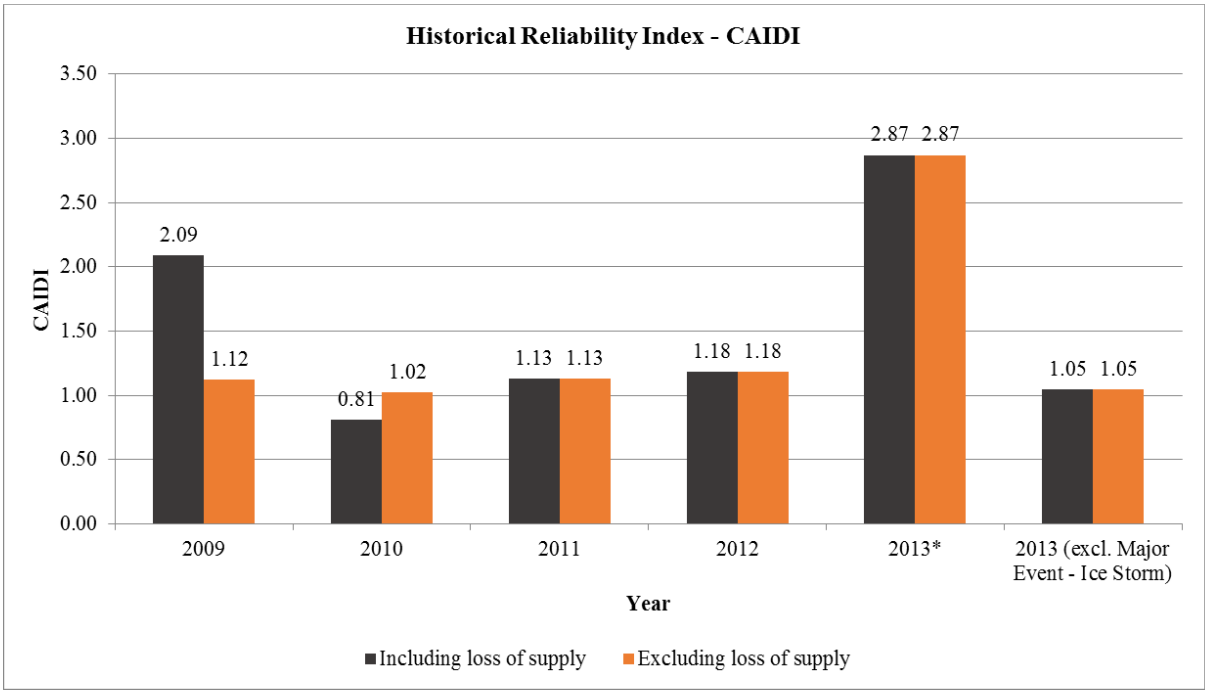
CAIDI is the average outage duration that any given customer would experience. It can also be viewed as the average restoration time following an outage, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{Total Customer Hours of Interruptions} = \text{SAIDI}}{\text{Total Customer Interruptions} = \text{SAIFI}}$$

Going forward, the OEB does not require the reporting of CAIDI.

Figure 3 shows the CAIDI performance for OPUCN during the past five years.

Figure 4: Historic CAIDI Performance



*Includes power outages due to the ice storm in December 2013 (an extreme weather event)

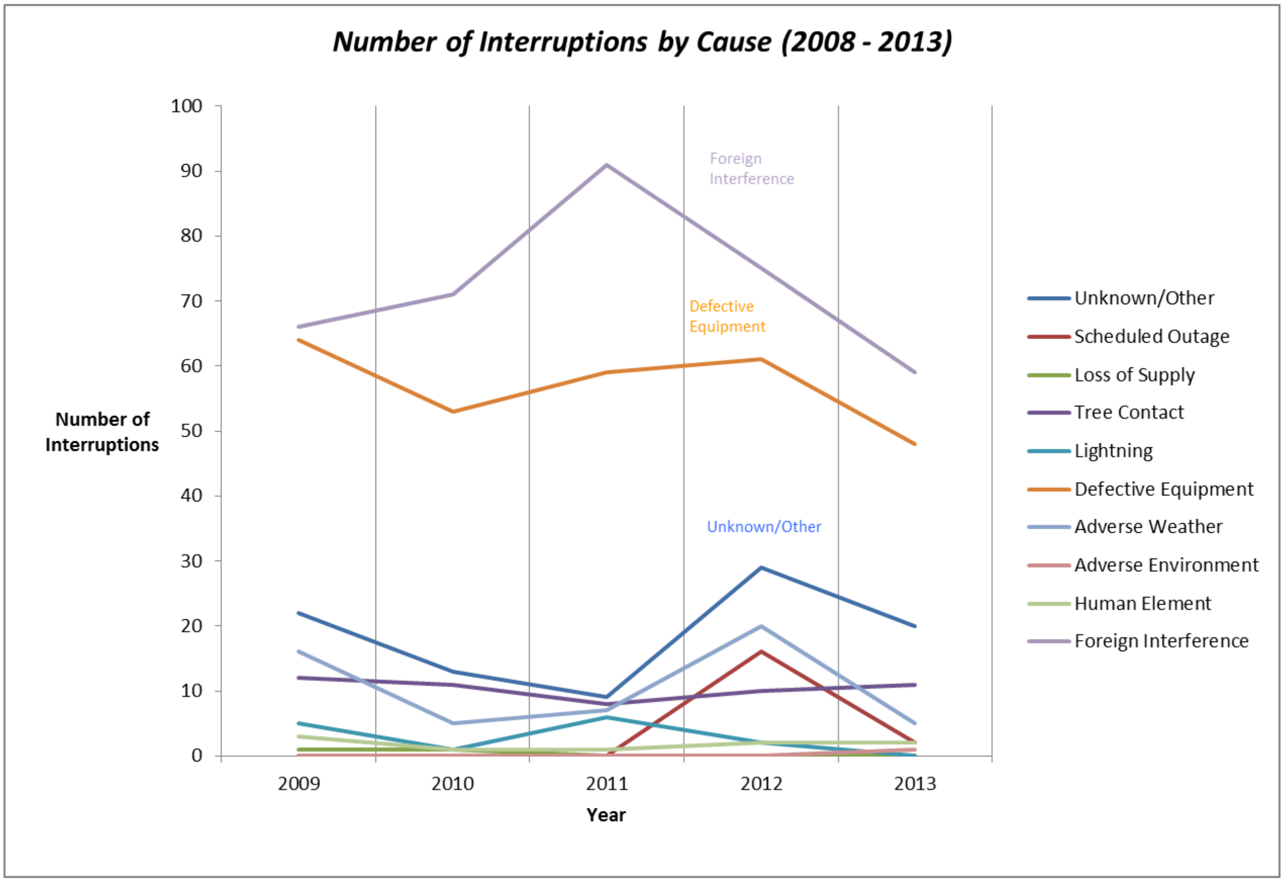
b. *Reliability Performance Impact on DS Plan*

System Renewal

Overall, not including the impact of the December 2013 ice storm, the foregoing reliability performance indicators show a positive trend in OPUCN's reliability performance. During the examined period capital investments have been completed to address significant identified root causes of outages, and outages have been reduced.

As illustrated in the Figure 4 below, OPUCN monitors and tracks on an annual basis, the number of outages by root causes.

Figure 5: Total number of Outages by Root Cause (2008–2013)



In recent years outages were primarily due to defective equipment (identified as defective porcelain insulators and switches) or foreign interference (squirrel contact). Consequently in 2013, OPUCN completed installation of animal guards. OPUCN also implemented a two year program to replace all porcelain insulators and switches with polymer type units. This has resulted in major reductions in outages specific to these causes and hence to overall number of outages.

In 2012, OPUCN had a total of 215 outages and in 2013, it experienced a total of 148 outages, a reduction of 31%. Out of the 148 total number of outages in 2013:

- 40% were due to animal (squirrel) contact (59 out of 148). By comparison, in 2012 there were 75 outages caused by animal contact. 2013 saw a reduction of 21% in this category.

- 32% were due to defective equipment (48 out of 148). Again by comparison, in 2012 there were 61 outages caused by defective equipment, 2013 saw a reduction of 21% in this category.

OPUCN also identifies projects in the System Renewal category to improve system reliability by mitigating the risk of in service failure of assets, significant outage duration and associated negative outage impact to its customers. With the guidance of the Asset Condition Assessment (ACA) report, along with its maintenance and inspection reports and underground primary cable fault analyses, OPUCN identifies assets in need of replacement. OPUCN then schedules these projects based on criticality and level of priority as indicated by its Asset Investment Prioritization Tool (see Part V, Section 2). OPUCN's Capital Investment Plan includes between $4 million and $5 million for these renewal projects in each year of the plan period.

Grid Modernization and Business Operation system improvements

While OPUCN's reliability trend is positive and outages continue to decline, OPUCN is listening to its customers on outage issues and intends to provide its customers with better visibility and more timely information related to outages.

OPUCN will implement distribution automation, including intelligent devices, equipment and systems, to reduce restoration time and minimize the number of customers being impacted by outages. OPUCN plans to complete the installation of an Outage Management System (OMS) by December 2015. The OMS will be fully integrated with OPUCN's SCADA, GIS, AMI, CIS and IVR, so that OPUCN will be able to proactively identify customers without electrical power, without waiting for customers to call in and report the outage. This OMS will help OPUCN:

- Proactively provide more frequent and more timely updates to customers during an outage (e.g. the area affected by the outage, number of customers affected, possible cause and when power may be restored).
- Reduce the duration, frequency and impact of interruptions.

- Assist in automation of the outage detection, restoration, and reporting process.

Overall, this modernization and associated operational system improvements will improve system reliability and provide enhanced value to its customers.

3. SERVICE QUALITY MEASURES

In addition to the reliability indices (SAIDI, SAIFI and CAIDI), OPUCN tracks its performance on the OEB's Electricity Service Quality Requirements (ESQR).

The OEB's *Distribution System Code* sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the *Ontario Energy Board Act, 1998*. As required by the OEB, OPUCN records and submits performance measures. These are compared with the OEB's established expected ESQR levels to evaluate OPUCN's performance in appointment scheduling, service accessibility and emergency response.

a. *Service Quality Performance*

Telephone Accessibility

Incoming calls to the distributor's customer care telephone number must be answered within the 30 second time period established as below:

- For qualified incoming calls that are transferred from the distributor's IVR system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the 30 seconds shall be counted from the first ring.

The OEB mandates that this service quality requirement must be met at least 65% of the time on a yearly basis. In 2013 OPUCN achieved 71% on this metric.

Telephone Abandon Rate

The OEB mandates that the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be 10% or less on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the 30 second period has elapsed. In 2013 OPUCN achieve 2% on this metric.

Emergency Response

The OEB mandates that emergency calls must be responded to within 120 minutes in rural areas and within 60 minutes in urban areas. This service quality requirement must be met at least 80% of the time on a yearly basis. OPUCN's 2013 achievement on both metrics was 100%.

Connection of New Services

The OEB mandates the following requirements for connection of new services:

A connection for a new low voltage service (<750 volts) must be completed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.

A connection for a new high voltage service request (>750 volts) must be completed within 10 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.

The OEB mandates that this service quality requirement must be met at least 90% of the time on a yearly basis. In 2013 OPUCN achieved 98% on low voltage connections and 100% on high voltage connections.

Service Quality Summary

OPUCN's 2013 and historical performance on these metrics is summarized in Table 10:

Table 10 – Electricity Service Quality Performance Measures

Metric	OEB Minimum Standard	2009	2010	2011	2012	2013
Connection of New Services (LV)	90% within 5 days	100.00%	92.30%	91.00%	96.52%	97.60%
Connection of New Services (HV)	90% within 10 days	100.00%	100.00%	100.00%	100.00%	100.00%
Appointments Scheduling	90% on a yearly basis	100.00%	99.90%	100.00%	100.00%	100.00%
Appointments Met	90% on a yearly basis	100.00%	99.10%	99.90%	99.90%	98.90%
Missed Appointments Rescheduled	100% on a yearly basis	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65% within 30 seconds	56.10%	59.20%	71.30%	71.30%	71.50%
Telephone Call Abandon Rate	10% or less after 30 seconds	5.50%	4.30%	2.10%	2.20%	1.60%
Written Responses to Inquiries	80% within 10 days	100.00%	100.00%	99.40%	99.40%	100.00%
Emergency Response (Urban)	80% within 60 minutes	100.00%	100.00%	100.00%	100.00%	85.71%
Emergency Response (Rural)	80% within 120 minutes	100.00%	100.00%	100.00%	100.00%	100.00%

b. *Impact on DS Plan/Continuous Planning Improvement*

While achieving or exceeding all ESQR metrics since 2011, one area of focus for OPUCN remains answering customer calls and providing information relevant to customers' enquiries. To this end, OPUCN plans to enhance its IVR, telephone and CIS systems in conjunction with its implementation of the proposed Outage Management System (OMS) to enable improved customer communication. The forecast cost of these enhancements is $190 thousand and is included in the OMS investment total.

4. OTHER PERFORMANCE MEASURES/METRICS – PEER COMPARISONS

As a general benchmark for its historical and planned capital investment levels, OPUCN has considered the data presented in the following tables. The data provided is taken from the Board's *Annual Yearbook of Electricity Distributors* and tracks the following measures for the years 2009 through 2013:

- Customer Growth

- Capital Expenditures per year
- Capital Expenditures per customer
- Net Fixed Assets per customer

Table 11: Comparator LDC Customer Growth Data

Customers	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	37,668	63,558	50,201	49,299	21,184	85,998	27,506	32,827	62,858	52,488	51,089	39,513	111,994
2010	37,654	64,329	50,890	50,250	20,790	86,611	29,142	32,911	62,674	52,710	51,914	39,669	112,569
2011	37,964	64,329	51,584	50,859	21,232	87,964	30,485	33,338	63,614	53,083	52,611	40,337	113,709
2012	38,260	65,377	51,983	51,553	20,893	89,025	32,324	33,883	64,106	53,361	53,387	40,915	115,280
2013	38,260	65,377	51,983	51,553	20,893	89,025	32,324	33,883	64,106	53,361	53,387	40,915	115,280
Average	37,961	64,594	51,328	50,703	20,998	87,725	30,356	33,368	63,472	53,001	52,478	40,270	113,766

Table 12: Comparator LDC Capital Expenditure Data

Capital Expenditures Per Year (Thousands)	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	5,760	18,081	10,500	16,475	3,366	15,260	7,367	5,921	19,045	6,351	17,409	5,525	30,741
2010	6,277	12,495	11,484	18,997	3,125	20,832	13,675	5,458	29,692	6,115	24,257	6,179	27,840
2011	4,877	10,310	9,845	24,307	4,345	22,910	9,626	6,433	29,861	18,284	38,215	5,080	25,290
2012	4,572	18,297	16,493	11,492	7,401	20,502	13,122	11,242	12,964	12,540	24,614	4,429	15,858
2013	4,572	18,297	16,493	11,492	7,401	20,502	13,122	11,242	12,964	12,540	24,614	4,429	15,858
Average	5,212	15,496	12,963	16,553	5,128	20,001	11,382	8,059	20,905	11,166	25,822	5,128	23,117

Table 13: Comparator LDC Capital Expenditure per Customer Data

Capital Expenditures Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	153	284	209	334	159	177	268	180	303	121	341	140	274
2010	167	194	226	378	150	241	469	166	474	116	467	156	247
2011	128	160	191	478	205	260	316	193	469	344	726	126	222
2012	119	280	317	223	354	230	406	332	202	235	461	108	138
2013	119	280	317	223	354	230	406	332	202	235	461	108	138
Average	137	240	252	327	244	228	373	241	330	210	491	128	204

Table 14: Comparator LDC Net Fixed Assets per Customer Data

Net Fixed Assets Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	1,592	1,330	1,669	1,838	1,404	1,638	1,560	1,522	1,766	992	2,154	1,582	1,330
2010	1,648	1,323	1,638	1,783	1,448	1,699	1,715	1,550	1,998	988	2,461	1,585	1,484
2011	1,645	1,339	1,655	2,222	1,485	1,780	1,770	1,549	2,223	1,178	2,933	1,559	1,565
2012	1,552	1,561	1,848	2,494	1,924	1,938	1,833	1,590	2,395	1,325	3,227	1,530	1,654
2013	1,547	1,553	1,999	2,561	2,125	2,011	1,784	1,597	2,422	1,436	3,279	1,671	1,720
Average	1,597	1,421	1,762	2,180	1,677	1,813	1,732	1,562	2,161	1,184	2,811	1,585	1,551

Consideration of this data for OPUCN and comparable Ontario LDCs indicates that:

- OPUCN's capital expenditure per customer for this historical period averaged third lowest among its comparators.
- OPUCN's Average Fixed Assets per Customer continues to be significantly below its comparator LDCs.

Comparing the average of the Average Net Fixed Assets per Customer of the other LDCs for 2013 ($1,977), with OPUCN's Average Net Fixed Assets per Customer ($1,436), and multiplying the difference ($1,977 - $1,436 = $541) by the OPUCN number of customers in 2013 (53,969), the difference in OPUCN's net fixed assets from the average of its comparators is approximately $29 million.

The need for OPUCN to increase its annual capital expenditures was acknowledged by the parties to OPUCN's most recent (2012) cost of service rate application. At page 12 of the November 20, 2006 Transcript from EB-2011-0073 remarks by counsel to School Energy Coalition in support of the settlement agreement placed before the Board in that proceeding are recorded as follows:

> *"So the ratepayers are concerned that this is a utility that does need investment. You can see from their statistics that their infrastructure needs some spending. And the ratepayers want them to do that…"*.

This DS Plan forecasts OPUCN's total net fixed assets in 2019 at $115,117,616. OPUCN's forecast number of customers in 2019 is 63,311 (using the definition of "customer" adopted by the Board for yearbook reporting purposes, which excludes streetlighting, sentinel lighting, and USL connections). OPUCN's forecast Average Net Fixed Assets per Customer in 2019 is $1,818, which remains below the <u>2013</u> average for the comparable LDCs. This analysis indicates to OPUCN that its planned capital investment levels remain fair and reasonable, and maintain an appropriate balance between maintenance and improvement of distribution service on the one hand, and sector leading cost levels on the other hand, all in line with indicated customer preferences and priorities.

OPUCN also compared its historical net OM&A per customer levels with those of its comparators, as indicated in Table 15.

Table 15: Comparator LDC Net OM&A per Customer Data

Net OM&A Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	205	208	197	194	209	142	195	199	163	168	172	214	174
2010	201	218	188	195	211	142	192	203	176	168	191	223	183
2011	176	225	209	251	227	155	210	198	206	191	182	214	181
2012	199	252	266	267	283	189	209	240	223	211	220	219	238
2013	199	252	266	267	283	189	209	240	223	211	220	219	238
Average	196	231	225	235	243	163	203	216	198	190	197	218	203

This data indicates that historically OPUCN has managed with among the lowest levels of OM&A costs per customer.

OPUCN forecasts its OM&A cost per customer for 2019 at $208, unchanged from 2013. This results from forecast OM&A costs increases being held at approximately 2% per year, in the face of customer growth forecast at 3% per year. OPUCN is thus confident that its forecast OM&A spending is also fair and reasonable, and maintains and appropriate balance between maintenance and improvement of customer service at sector leading cost levels.

IV. OPUCN'S ASSET MANAGEMENT PROGRAM

1. OVERVIEW

OPUCN is committed to building sustainable and reliable infrastructure to service the needs of its community and to comply with regulatory obligations and license conditions. OPUCN's infrastructure investment decisions are guided by objectives to achieve optimal performance of its assets at a reasonable cost with due regard for safety, system reliability, and customer service expectations.

OPUCN uses a risk based asset management strategy to:

- Determine the risk of asset failure based on the condition of the asset ("asset health indices");
- Compute the valuation of the risk, based on probability and consequences of asset failure; and
- Identify the optimal risk mitigation alternative through an evaluation of available options.

OPUCN's asset management program considers and reviews the following inputs:

- Asset condition assessments (normally conducted every two to three years)
- Operational safety and employee/public safety reports
- Maintenance and operational inspection and test reports on assets
- System reliability - power outage incident reports with information on root cause, duration, fault locating, restoration time, customer impact and worst performing feeders
- Aged plant/infrastructure inventory, to identify high risk of failure and risk mitigation options
- System capacity constraints at both the distribution and transmission level and considering future loading requirements
- Customer and municipality requests

- New technology to increase operational efficiencies through grid modernization ("smart grid") infrastructure to provide better system visibility and relevant information to both OPUCN and its customers
- Renewable or distributed generation connections

In 2013, OPUCN retained METSCO to complete an Asset Condition Assessment (ACA) on OPUCN's major distribution plant assets to determine overall asset conditions. METSCO is a recognized consulting firm with expertise in asset management condition assessment using the PAS-55 methodology, developed by British Standards Institute, to conduct best in class strategies for risk management associated with fixed assets of electricity distribution systems. METSCO's report identifies critical or poor condition assets that need to be replaced to avoid risk of in service failure that would cause unacceptable customer impacts.

METSCO also prepared a five year Asset Management Plan based on asset condition, age, optimal operating conditions, end of useful service life and financial/budget considerations.

A copy of the METSCO report is filed as Exhibit 2, Tab B, Schedule 3. This report has been instrumental in the formulation of OPUCN's System Renewal program for the plan period.

To help smooth out the level of investments over the five year period and help mitigate rate impacts, OPUCN's asset management program includes the use of an Asset Investment Prioritization Tool to prioritize projects. The prioritization model is based on weighted criteria such as: safety, criticality of in service failure and outage impacts (system reliability); legacy installations; environmental impacts; regulatory compliance; age of assets; operational efficiencies; and capital investment compared to continued maintenance or repair costs.

In 2012-2013, OPUCN conducted an overhead plant inspection to confirm data accuracy in OPUCN's Geographical Information System. This inspection also helped identify and confirm potential equipment hazards and critical assets in need of repair or replacement. Data accuracy in the asset registry is key when conducting an asset condition assessment and determining what capital investments need to be completed and included in the DS Plan.

OPUCN's asset management program has also been informed by its plan to modernize its distribution grid. OPUCN engaged a third party consultant (UtiliWorks) to assess current grid status and develop a *Smart Grid Roadmap and Financial Analysis*. This report (filed as Exhibit 2, Tab B, Schedule 4) outlines several initiatives that would help OPUCN implement a "smarter grid" to increase efficiencies in its system operations, avoid or shorten system outages, and best provide service value to its customers.

OPUCN has applied due diligence in ensuring that its project costs are reasonable and in line with standard practices. OPUCN retained the engineering services of NBM to independently develop project estimates on defined system renewal projects, including the installation of the new municipal substation (MS9). A copy of NBM's report is filed as Exhibit 10, Tab B. This report validates the reasonableness of OPUCN's cost estimates for the projects identified.

Page 4 of the NBM report presents NBM's cost estimates for each of the OPUCN plan period programs projects that NBM reviewed. NBM was not provided with OPUCN's cost forecasts for these programs, but rather was asked to develop its own cost estimates independently based on project descriptions provided by OPUCN and NBM's own inquiries of OPUCN to complete its understanding of the projects. Table 16 below maps the NBM cost summary for each of these programs against OPUCN's own costing for the subject programs, by plan year. The comparison illustrates the reasonableness of OPUCN's cost forecasts, which in each case are equal to, or less than, the cost estimates derived by NBM. (In the case of the proposed MS-9 DS, OPUCN's DS Plan includes $1M in 2019 for MS9 investments which is not included in this table. NBM assumed MS9 investment completed in 2018. OPUCN forecasts completing MS9 investment in 2019. NBM does not include MS9 amounts in 2019, so the presentation of OPUCN costs in this table excludes 2019 MS9 costs as well. Total forecast OPUCN cost for MS9 and associated feeders is $9 million compared to NBM's total cost of $10.2 million.)

Table 16: Comparison Between NBM and OPUCN Project Estimates

Summary Comparison between NBM and OPUCN Planned Projects Estimates			
2015 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,858,334.07	$2,410,000.00	
Planned UG Projects	$962,687.65	$843,000.00	
Prop MS-9 Station	$1,126,220.01	$750,000.00	
MS10 Breaker Replace	$105,000.00	$105,000.00	
MS11 breaker replace	$105,000.00	$105,000.00	
2015 Total Estimate:	***$5,157,241.72***	***$4,213,000.00***	
2016 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,344,241.52	$2,255,000.00	Does not include pole replacement program
Planned UG Projects	$1,367,338.42	$1,007,000.00	
Prop MS-9 Station	$2,508,653.63	$1,000,000.00	
MS2 Breaker Replace	$105,000.00	$100,000.00	
MS15 Breaker replace	$70,000.00	$40,000.00	
2016 Total Estimate:	***$6,395,233.57***	***$4,402,000.00***	
2017 Cost Estimate Summary			
	NBM	**OPUCN**	
Planned OH Projects	$1,978,695.91	$1,855,000.00	Does not include pole replacement program
Planned UG Projects	$1,413,165.00	$1,087,000.00	
Prop MS-9 Station	$2,969,112.00	$3,250,000.00	
44kV OCB Replacement	$680,000.00	$500,000.00	
2017 Total Estimate:	***$7,040,972.91***	***$6,692,000.00***	
2018 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,174,744.72	$2,310,000.00	Does not include pole replacement program
Planned UG Projects	$1,868,038.00	$921,000.00	
MS-9 Station	$3,600,233.56	$3,000,000.00	
44kV OCB Replacement	$680,000.00	$500,000.00	
2018 Total Estimate:	***$8,323,016.28***	***$6,731,000.00***	
2019 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,063,930.92	$1,917,000.00	Does not include pole replacement program
Planned UG Projects	$994,736.58	$904,000.00	
MS-5 Station	$1,350,000.00	$1,000,000.00	
44kV OCB Replacement	$510,000.00	$500,000.00	
2019 Total Estimate:	***$4,918,667.50***	***$4,321,000.00***	

Though not commissioned to do so, METSCO also produced summary costing for the capital investments identified in the METSCO report for sustainment of OPUCN's fixed assets. Table 17 below maps MESTCO's cost estimates against OPUCN's for each of the relevant System Renewal capital program categories during the plan period.

Table 17: METSCO and OPUCN Budget Summary Comparison

SYSTEM RENEWAL - METSCO AND OPUCN BUDGET SUMMARY COMPARISON												
CAPITAL INVESTMENTS CATEGORY	**2015 OPUCN**	**2015 METSCO**	**2016**	**2016 METSCO**	**2017**	**2017 METSCO**	**2018**	**2018 METSCO**	**2019**	**2019 METSCO**	**Total OPUCN 2015-2019**	**Total METSCO 2015 - 2019**
SYSTEM RENEWAL	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
OH REBUILDS	2,410	2,727	2,455	2,727	2,055	2,347	2,510	2,347	2,117	2,347	11,547	12,498
UG REBUILDS	1,133	1,394	1,007	1,394	1,087	1,394	921	1,594	904	1,444	5,052	7,223
STATIONS REBUILDS	510	183	640	183	500	500	500	500	1,000	1,375	3,150	2,744
Total Planned Plant Rebuilds	***4,053***	***4,304***	***4,102***	***4,304***	***3,642***	***4,241***	***3,931***	***4,441***	***4,021***	***5,166***	***19,749***	***22,465***
Reactive/emergency Plant Replacement	830		830		830		830		830		4,150	
TOTAL SYSTEM RENEWAL (OH, UG and Stations rebuilds)	**4,883**	**4,304**	**4,932**	**4,304**	**4,472**	**4,241**	**4,761**	**4,441**	**4,851**	**5,166**	**23,899**	**22,465**

Note:
1) METSCO's Capital Budgetary investments include only Planned replacements.
2) In 2015, OPUCN Station rebuilds included MS14 Switchgear Carry over
3) OPUCN starts the 3 year replacement program of the 44KV Oil circuit breakers in 2016; whereas METSCO suggested start date is 2017
4) Over the 5 year period, OPUCN is higher than METSCO by ~$1.4M but this gap is subject to the amount of actual Emergency replacements that occur annually

OPUCN's forecast costs for these programs exceed those provided by METSCO by approximately 6.7% over the plan period (approximately $1.5 million). However, OPUCN's comparative figures include unplanned, "reactive" asset replacements (discussed at Part I, Section 2., subsection c.(ii), above), separate provision for which totals approximately $830,000 per year, or $4.15 million over the plan term, in <u>addition</u> to identified System Renewal projects. METSCO's figures do not include provision for such unplanned "reactive" asset replacements. When OPUCN's reactive System Renewal provisions are deducted from OPUCN's total forecast costs for these System Renewal programs, OPUCN's forecast costs for the subject programs are <u>less</u> than METSCO's cost estimates by approximately $2.65 million over the plan period, or $543 thousand annually.

2. ASSETS MANAGED

OPUCN owns and operates a distribution network that currently serves approximately 55,400 customers in the City of Oshawa and the Region of Durham. The service territory of OPUCN covers 149 square kilometres consisting of 78 square kilometres of rural service area and 71 kilometres of urban service area. OPUCN's distribution system consists of:

- 8 municipal substations with 16 sub-station power transformers;
- 495 kilometres of overhead primary lines;
- 411 kilometres of underground primary cables;
- 11,397 poles of which 10,914 are wood poles, 463 are concrete poles, and 20 are steel poles;
- 6,571 distribution transformers; and
- 55,190 meters of which 54,382 are Smart Meters installed for Residential and General Service <50kW customers.

OPUCN receives power from HONI Transmission at 44kV from the following two transmission stations (TS):

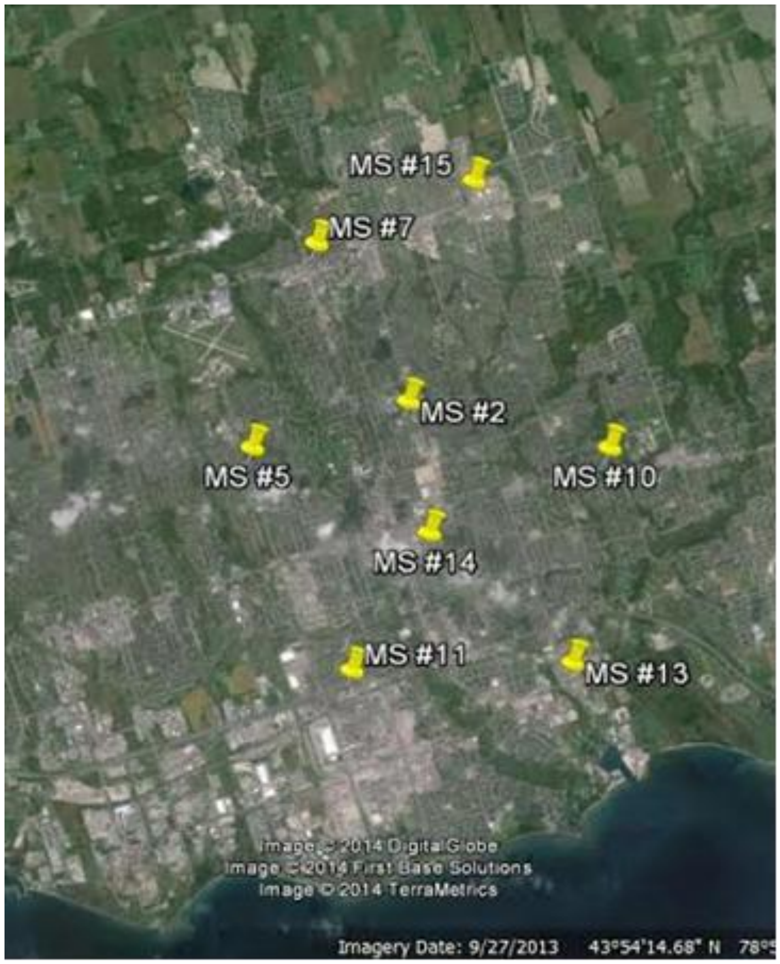
- Wilson TS – located at 698 Wilson Rd. N (North of Rossland Rd. E); and
- Thornton TS – located at 386 Thornton Rd. S (South of Gibb St.).

There are eight 44kV feeders that leave Wilson TS and four 44kV feeders that leave Thornton TS. This high voltage is stepped down from 44kV to 13.8kV at OPUCN's eight distribution or municipal substations, the locations of which are shown in the Figure 6 below.

Each distribution substation is equipped with two 44kV/13.8kV power transformers, each protected by a 44kV circuit breaker. Each station houses a metal clad switchgear that contains two transformer breakers and one bus tie breaker between two 13.8kV buses that are each equipped with 13.8kV circuit breakers to protect outgoing 13.8kV feeders.

OPUCN operates a primary "loop distribution" system which offers flexibility in switching operations to minimize outage durations and impact.

Figure 6: OPUCN Distribution Station Locations



OPUCN distributes electricity within the City of Oshawa through 12 44kV primary feeders and 47 13.8kV distribution primary feeders. The primary distribution network consists of approximately 496 km of overhead primary lines and 411 kilometres of underground primary cables, which in turn supply distribution type transformers that step down to low voltages that provide electricity to Oshawa customers.

Low voltage circuits supplied from the distribution transformers include: i) 120/240 V, 1-ph circuits to serve residential or small commercial customers; ii) 120/208 V 3-ph circuits to serve commercial customers; and iii) 347/600 V 3-ph circuits to serve commercial and industrial customers. OPUCN also supplies 27 large industrial customers at 44kV.

Oshawa has included in its DS Plan the construction of a new municipal/distribution substation (MS9), including station transformers, switchgear and associated equipment, and associated primary distribution plant, to supply the projected load growth in North Oshawa over the five year DS Plan period.

3. ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

OPUCN adopts standard depreciation guidelines to determine standard end of useful life for its assets. OPUCN performs routine maintenance and inspection to help determine the condition of its assets.

Proactive replacement of major assets that require significant effort to replace, involve large capital investments and have long lead times for material or equipment delivery, are completed based on results of an Asset Condition Assessment (ACA). This avoids service failures that may cause major outage impacts to customers. Station power transformers and station switchgear are examples of such assets.

Assets that are quick to replace, do not require large capital investments and do not cause significant customer outages are “run to failure” and replaced on an emergency basis.

OPUCN’s present asset monitoring and testing practices, data from which informs the ACA, are as follows:

a) All critical assets installed at substations are monitored through OPUCN’s SCADA system.

b) Critical assets installed in substations are physically inspected monthly. Major maintenance on substation equipment is carried out based on the needs indicated through these monthly inspections.

c) Underground vaults and manholes in the downtown core are deemed critical and are inspected annually with maintenance being carried out on an as required basis.

d) Overhead lines, underground pads and underground vaults outside of the downtown core are inspected on a three year cycle, in compliance with OEB requirements.

e) Tree trimming is carried out on a three year cycle as part of OPUCN's routine planned maintenance program. As required, OPUCN's contracted forestry crew inspect power lines for tree limbs or vegetation growing too close to the lines or at risk of falling into the lines, outside of planned cycle.

f) Infrared scan of all critical assets (overhead primary lines, distribution transformers, substation equipment) is carried out annually.

g) OPUCN conducts on-going visual inspections of its poles and completes non-destructive testing of the in-service poles once every 10 years to determine physical condition of the pole. Poles older than 30 years or those with previously identified risks are included annually in the testing. Very poor or critical poles are replaced within the year if not immediately.

h) Representative samples of older vintage cables with service age in excess of 35 years are tested every three to four years to determine the remaining useful life. CableWise testing checks the condition or deterioration of the conductor, insulation, splices/joints and terminations.

In parallel with the fixed asset physical condition monitoring and testing described above, performance indicators, particularly those related to equipment failures and root causes of power interruptions, are analyzed. Common causes are identified, and system enhancement or replacement projects are proposed where failures have significant implications for service reliability. Analysis is then done to determine if the cost to continue making repairs (given the frequency of failure and likelihood of future failures), is more or less than the cost of replacement or upgrade.

Data from the foregoing testing program and performance indicator analysis is comprehensively analyzed and the condition of each of OPUCN's significant assets is ranked on a scale of 1 to 100. This exercise allows identification of the assets with poor and very poor condition for input into the Asset Investment Prioritization Tool described in Part V, Section 2, below.

V. DEVELOPMENT OF THE CAPITAL INVESTMENT PLAN

In developing its five year Capital Investment Plan, OPUCN reaffirms the need or criticality of all projects. This process includes management meetings held with the Supervisor of Design, Manager of Design, Manager of Distribution Construction and VP Engineering & Operations to reassess the need, risks, costs, impacts and benefits of each proposed project, and to reaffirm if the project should be included in the rolling five year capital plan and consider any alternative solutions. The projects that are a “go” will proceed to the prioritization process to determine the implementation plan or schedule.

1. PROJECT ESTIMATES

OPUCN designers initially determine the high level estimates for the projects based on the high level description or scope of work. In determining the estimates, OPUCN references actual costs from past projects that had similar scope to the proposed project. Preliminary job planning is completed for most projects to ascertain any obvious unusual site conditions or overtime requirements to factor into the estimates. Once the scope is reasonably established, designers use the applicable labour, material and contract rates with approximately 10-15% contingency (depending on the complexity of the project) to cover unknown site conditions or potential future minor change in scope.

OPUCN, through a competitive bid process, secures three or five year contracts with some large material and equipment suppliers and civil contractors, and thus secures reasonable costs for material and contract service activity. Standard crew labour and vehicle rates, along with applicable inflation increases are used to calculate reasonable estimates for the scope of work defined on the projects.

2. PRIORITY OF PROJECTS/IMPLEMENTATION PLAN

To help determine the priority and scheduling of the projects within the five year Capital Investment Plan period, OPUCN uses its Asset Investment Prioritization Tool. This tool AIP is a risk probability and risk consequences matrix whereby, based on the several factors considered, projects are defined as; i) “minor”, “moderate”, “major” or “critical” in terms of risk consequences; and ii) "unlikely", "somewhat likely", "likely" or "almost certain" in terms of probability. The projects assessed are then plotted against both risk consequences and probability. Higher consequence and probability projects get a higher implementation priority.

The key consequence factors considered in the model are:

- Public and employee safety;
- Asset condition assessment;
- System performance indicators (SAIDI, SAIFI, outage frequency and duration);
- Power outage incident reports including root causes, duration, fault locating, restoration time, and customer impact data;
- System capacity constraints considering future loading requirements;
- Environmental impacts;
- Regulatory requirements;
- Third party requirements and scheduling co-ordination;
- Budget and rate impacts; and
- Upgrades on technology that would provide additional efficiencies, service level improvements and cost savings.

The prioritization results for OPUCN's DS Plan period projects are detailed in Exhibit 2, Tab B, Schedule 5.

3. CAPITAL INVESTMENT PLAN APPROVAL PROCESS

The five year Capital Investment Plan review and approval process is as follows:

- There are a number of iterations that typically involve input from, and updates by, the various department managers before the final five year draft Capital Investment Plan and associated budget/estimates are finalized.

- The draft five year Capital Investment Plan is then reviewed with the VP Engineering & Operations and the CEO to review justification of projects and associated expenditures, including project prioritization and implementation schedule.

- The Capital Investment Plan including the associated budgets is then presented to the Capital Committee, (a sub-committee of the Board of Directors), for review and recommendation of the following year's capital program and associated budget.

- The following year's recommended capital program and associated budget, is then presented for approval by OPUCN's Board of Directors.

- Once approved by the Board of Directors, the Capital Investment Plan is the plan against which actual costs and variances are tracked and explained. Any significant changes (more than 10%) in project scope or project costs require approval from the VP Engineering & Operations and the CEO. If approved, these changes are then reviewed at the next Capital Committee meeting for acceptance.

VI. CAPITAL INVESTMENT PLAN: 2015-2019

1. HISTORICAL AND DS PLAN PERIOD CAPITAL EXPENDITURE SUMMARY

Table 18 provides a summary of OPUCN's capital expenditures over a ten year period: four historical years, the 2014 Bridge Year, and the five test years 2015-2019. Capital expenditures are allocated in the four investment categories defined in the OEB's Guidelines; System Access, System Renewal, System Service and General Plant. System O&M expenditures are also included.

Table 18: Historical & Planned Capital Investment: 2010-2019

	HISTORICAL PERIOD					Bridge Year	FORECAST PERIOD				
	2010	2011	2012		2013	2014	2015	2016	2017	2018	2019
CATEGORY	Actual	Actual	Board Approved Plan	Actual	Actual	Plan	Plan	Plan	Plan	Plan	Plan
	$ '000	$ '000	$ '000		$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	1,447	8,913	2609	2899	4,042	3,867	8,995	4,140	3,550	3,435	3,455
System Renewal	4,637	7,039	7,037	7,162	5,971	5,958	4,883	4,932	4,472	4,761	4,851
System Services	0	0	0	0	1,903	2,830	2,868	2,830	4,670	4,645	3,050
General Plant	775	1,476	1500	2302	531	634	1,675	1,180	755	730	510
Total Capital GROSS	**6,859**	**17,428**	**11,146**	**12,363**	**12,447**	**13,289**	**18,421**	**13,082**	**13,447**	**13,571**	**11,866**
Third Party Capital Contribution	**2,173**	**931**	**925**	**1,271**	**1,699**	**1,560**	**4,911**	**1,455**	**1,075**	**1,095**	**1,105**
Total Capital Expenditure NET	**4,686**	**16,497**	**10,221**	**11,092**	**10,748**	**11,729**	**13,510**	**11,627**	**12,372**	**12,476**	**10,761**
System O&M	1,576	1,798	2,392	2,262	2,233	2,337	2,634	2,860	2,999	3,015	2,878

The following are explanatory notes:

- ***OPUCN's 2012 Rates Settlement:***

The 2012 Rates Settlement Agreement included a reduction in the 2011 planned capital investment from $10.7 million to $8.6 million, and an approved 2012 planned capital investment of $10.2 million (in service).

- ***2014 figures:***

The number of months of actual data included in Bridge Year (2014) is nine months.

- ***Historical variances by category:***

System Access: Prior to 2012, typical annual system access expenditures were approximately $2 million influenced by the economic downturn. From 2012 to

2014 customer growth returned due to Oshawa's revitalization programs and University of Ontario Institute of Technology (UOIT) increase in student registration and wind turbine installation. In 2011, the significant actual expenditure of approximately $8.9 million is due to Smart Meter Implementation (~$6.8 million) being recognized in 2011.

System Renewal: Historically and prior to 2011, typical renewal spend was approximately $4 to $5 million. However, in 2011, 2012 and 2013, critical station assets (power transformers) at end of life needed replacement, causing an increase of approximately $3 million in each of those years. In November 2013, transformer T1 at MS 5 was taken out of service due to very poor/critical gas test results and was scheduled to be replaced in May 2014. In 2014, the switchgear at MS14 was also replaced due to accelerated corrosion that materialized from a 2008 station fire.

System Service: Historically and prior to 2012, this expenditure type was insignificant.

- ***Plan vs. actual variances for total expenditures:***

In 2011, 54% variance in actual expenditure of $16.5 million versus plan of $10.7 million is mainly due to the Smart Meter implementation.

In 2012, 9% variance mainly due to fleet delivery in December 2011 but placed in service in 2012, along with unplanned purchase of software solution to correct GIS connectivity, offset by customer contributions.

In 2013, 14% negative variance is underspend of ~$1.7 million due to completion delays in phase 1 of grid modernization project and overhead plant rearrangement.

OPUCN’s capital expenditure for the period 2008 through 2014 is summarized at Part I, Section 2, above.

For 2015 through 2019 OPUCN’s total capital expenditure is forecast to be approximately $60.8 million, with a net average annual investment of $12.2 million. OPUCN’s critical system renewal capital investment requirements have stabilized, with future capital expenditures on existing assets being more at a “sustaining” level (i.e. in line with annual depreciation expense) of $4.5 - $5 million per year. Customer growth and related capacity requirements are the main drivers for OPUCN’s significant incremental capital investment requirements over the planning period.

2. INPUTS AND DRIVERS

The following are the main inputs and drivers for development of OPUCN's 2015 through 2019 Capital Investment Plan:

- Forecast increase in service connections and system expansions and metering requirements, based on projected growth in customer connections, developed through OPUCN's consultations with the City, the Region, and local developers.
- Projected increase in system demand and peak load resulting from anticipated accelerated growth in residential subdivisions and commercial developments, including growth arising from the opening of the Highway 407 extension through Oshawa, which is scheduled to open in 2015.
- Projected system capacity constraints at both distribution and transmission levels in light of projected loading requirements (leading to identification of the need for a new distribution substation (MS9) to handle future distribution capacity requirements at the north end of Oshawa, and, as identified through on-going regional and local planning meetings provision for cost contributions towards interim and permanent solutions to address transmission capacity constraints).
- Third party requests for OPUCN plant relocation.
- Recommendations from METSCO's 2013 *Asset Condition Assessment Report and Asset Investment Plan* report.
- Maintenance and operational inspection and tests reports.
- Power outage incident reports and associated analysis of root cause, duration, fault locating, restoration time, customer impact and worst performing feeders.
- Consideration of effective and proven technology to increase business operation efficiencies, provide better system visibility, improve reliability and provide appropriate, timely and up to date information to both OPUCN's staff and its customers (including investment in an Outage Management System (OMS) that is fully integrated with OPUCN's other grid operation and customer service systems).
- Consideration of Investments required or advisable to improve OPUCN work environments and staff satisfaction and efficiency.

- Consideration of required or advisable IT system upgrades (software and hardware) including GIS, AMI, CIS and financial systems improvements or upgrades.

a. *Results of Asset Condition Assessment (ACA)*

The ACA informing OPUCN's 2015-2019 Capital Investment Plan was performed by METSCO (see Exhibit 2, Tab B, Schedule 3).

The assets covered by the report include:

i) Distribution substations;

ii) Overhead distribution primary lines;

iii) Underground distribution primary cables;

iv) Distribution transformers; and

v) Switches and cut-outs installed in pole-mounted and pad-mounted configurations.

The following is a summary of the key findings and recommendations from METSCO's report.

(ii) Distribution Substations

The main components of the substations include:

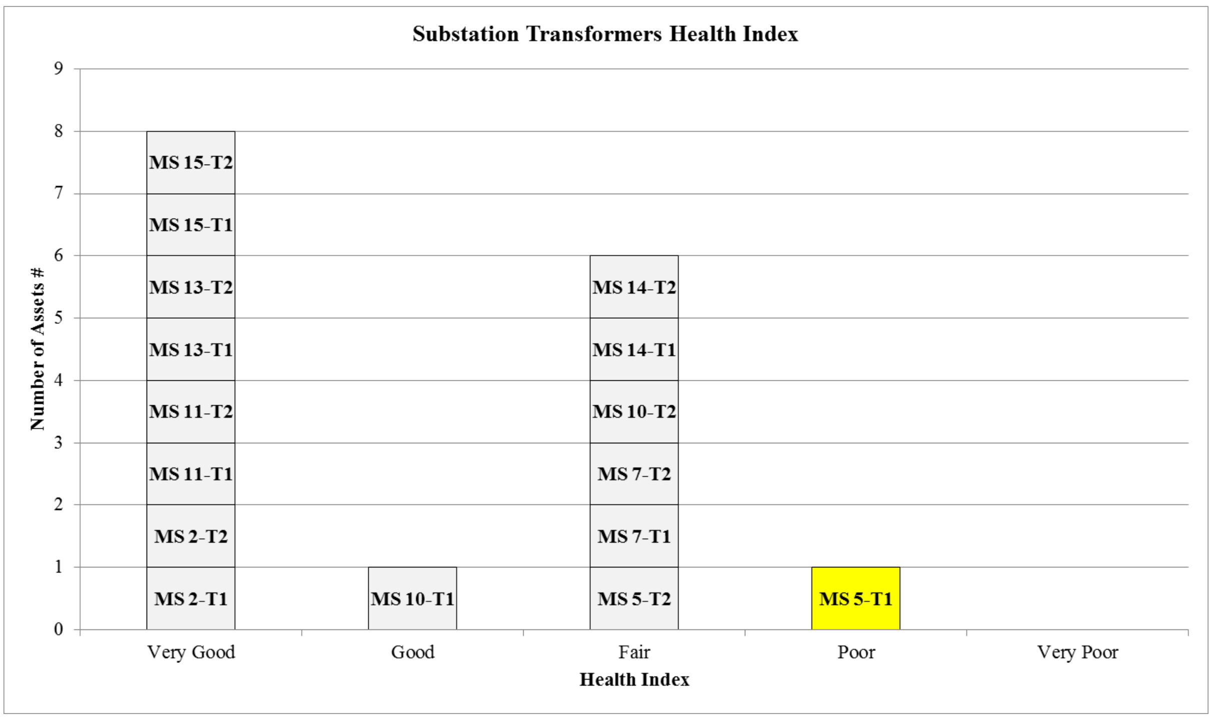
- Power transformers
- 44 kV circuit breakers
- 13.8 kV switchgear/circuit breakers
- Protection relays, controls and remote terminal units (RTUs)
- Control batteries and chargers
- Substation buildings and yards
- Ground grids

Substation Power Transformers

Generally the substation power transformers have been found to be in fair or good condition.

As shown in Table 19 below, Transformer MS-5-T1 is determined to be in "poor" condition based on the gas in oil analysis completed in September 2013. This transformer was taken out of service due to high concentration of combustible gases in oil and replaced in the second quarter of 2014.

Table 19: Health Indices – Substation Power Transformers

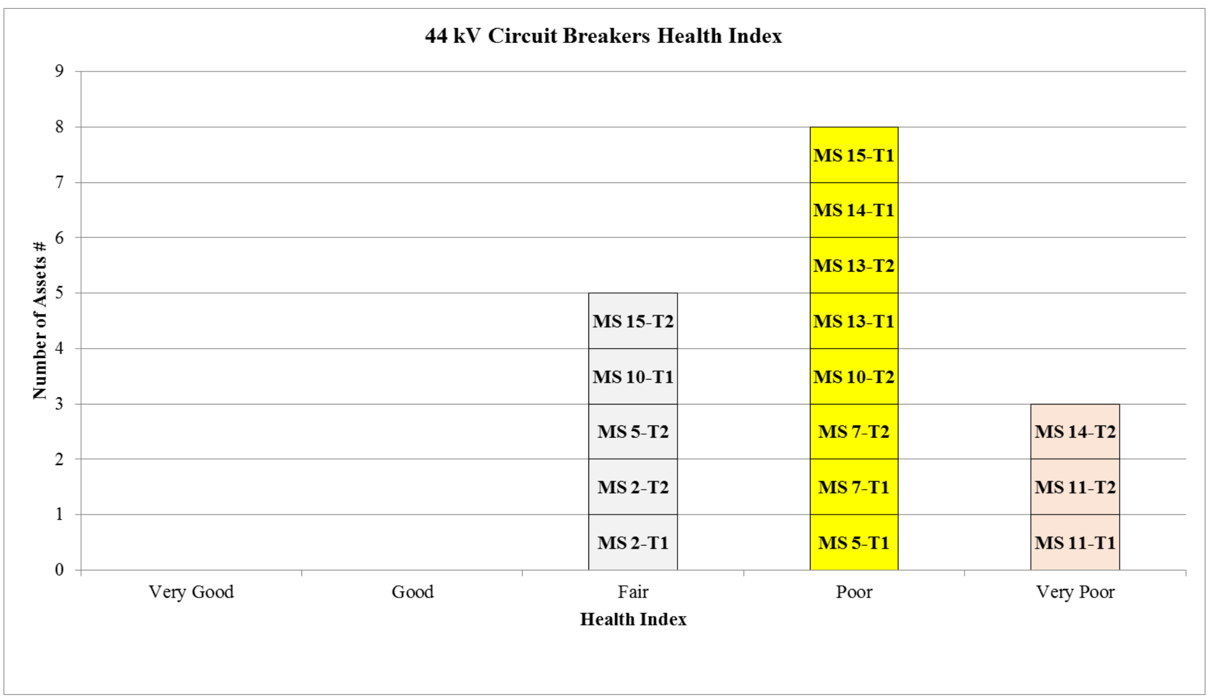


44kV circuit Breakers

All of the 44kV circuit breakers are outdoor type oil-circuit breakers. This circuit breaker design technology has become obsolete and breakers of this type have not been in manufacture for more than 25 years. The three newest breakers in service are now 29 years old but some of the older breakers have already reached service lives of 45 years. OPUCN will have difficulty obtaining parts for these breakers as the existing fleet gets older and requires repairs

The health indices for 44kV circuit breakers, based on circuit breaker age/vintage, oil tests and visual inspections, are summarized in Table 20. It was recommended that all breakers with poor and very poor health indices, a total of 11 breakers, be replaced during the next five years. Total DS Plan forecast expenditure for the replacements is approximately $1.5 million (included in the System Renewal category).

Table 20: Health Indices – 44 kV Circuit Breakers

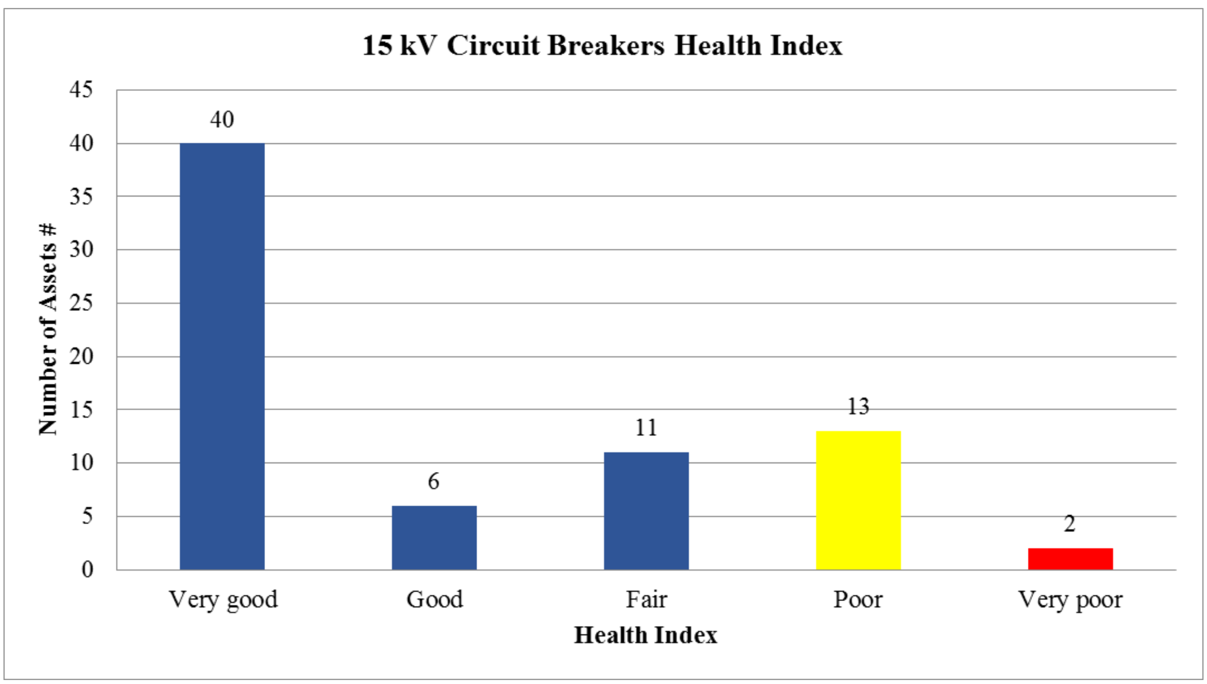


13.8kV switchgear and circuit breakers

On the 13.8kV bus, each substation has nine circuit breakers; two incoming breakers, one tie breaker and six feeder breakers. For the eight substations, there are a total 72 - 15kV class circuit breakers in metal clad switchgear employed at the different substations.

The original circuit breakers were of magnetic air design type. In 2007 OPUCN embarked on a program to replace the aging magnetic air breakers with modern vacuum circuit breakers within existing switchgear cells. This method has proven to be a cost effective and reliable method for breaker replacement. While a majority of the magnetic-air circuit breakers have now been replaced with vacuum breakers, the remaining few are scheduled for replacement during 2014-2016. Table 21 below presents the Health Indices of all the 13.8kV circuit breakers. It was recommended all breakers with poor and very poor health index, total of 15, be replaced during the next five years. Total DS Plan forecast expenditure for these replacements is approximately $350 million (included in the System Renewal category).

Table 21: Health Indices – Substation 13.8 kV Circuit Breakers



Protection Relays, Controls and Remote Terminal Units (RTUs)

The original RTUs at each of the stations were installed in 1991 and in 2006 the CPU boards were updated. The Remote Terminal Units (RTU) of all the OPUCN substations were determined to be in “fair” condition and do not require any additional upgrades during the 2015-2019 period.

Control Batteries and Chargers

OPCUN has standardized its substation batteries to BAE SECURA lead acid batteries and STATICON chargers. This battery/charger system generally provides a service life of about 12 years. The batteries and chargers have been determined to be in “good” or “very good” condition. However, based on the service age, the battery and charger at MS-5 may need replacement during the following five year (2020–2024) period. OPUCN will monitor this condition.

Substation Buildings and Yards

Based on the condition assessment for substation buildings and yards, MS-14 was ranked to be in “fair” condition. All the substation buildings were found to be in “good” or “very good” condition, except for MS15 & MS10, whose roofs require replacement as it is no longer cost effective to continue with maintenance. These roof replacements are required to avoid water leakage and potential unsafe operating conditions and or potential loss of station. OPUCN completed one replacement in 2014, and the second is in progress.

For MS-14, the feeder cables connecting the station breaker to the overhead lines were found to be in poor condition requiring replacement. OPUCN included these feeder cables replacements as part of MS 14 switchgear replacement in 2014.

Ground Grids

The ground grids at MS2, MS11 and MS15 were tested by OPUCN and found to be in good condition. There are no records available of ground grid testing for the remaining five substations and it is not possible to determine the effectiveness at these remaining stations, without testing of the ground grids.

OPUCN plans to conduct ground grid testing during the period 2015 – 2017 at each of the remaining five substations to determine their condition and effectiveness. The annual cost of this planned testing is approximately $20 thousandK. At this point

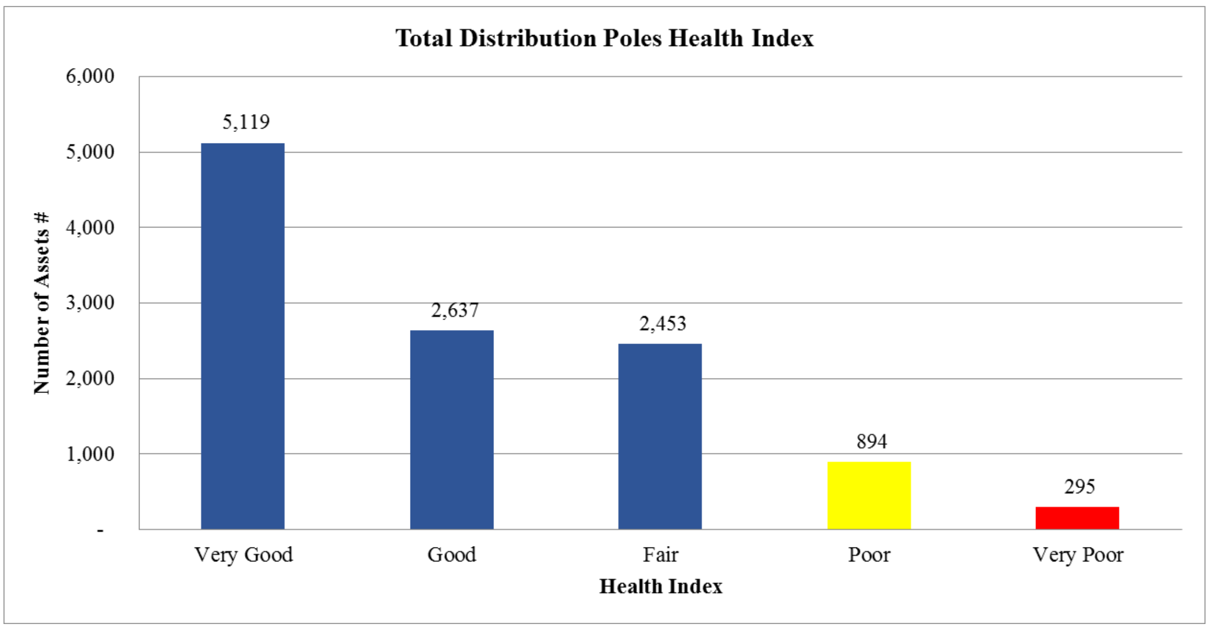
OPUCN's Capital Investment Plan does not include any costs for ground grid work that such testing might identify.

(iii) Overhead Distribution Poles and Primary Lines

Poles

By taking into account the age and results of field inspections, the health indices for all distribution poles have been determined and the results are indicated in Table 22.

Table 22: Health Indices – Distribution Poles



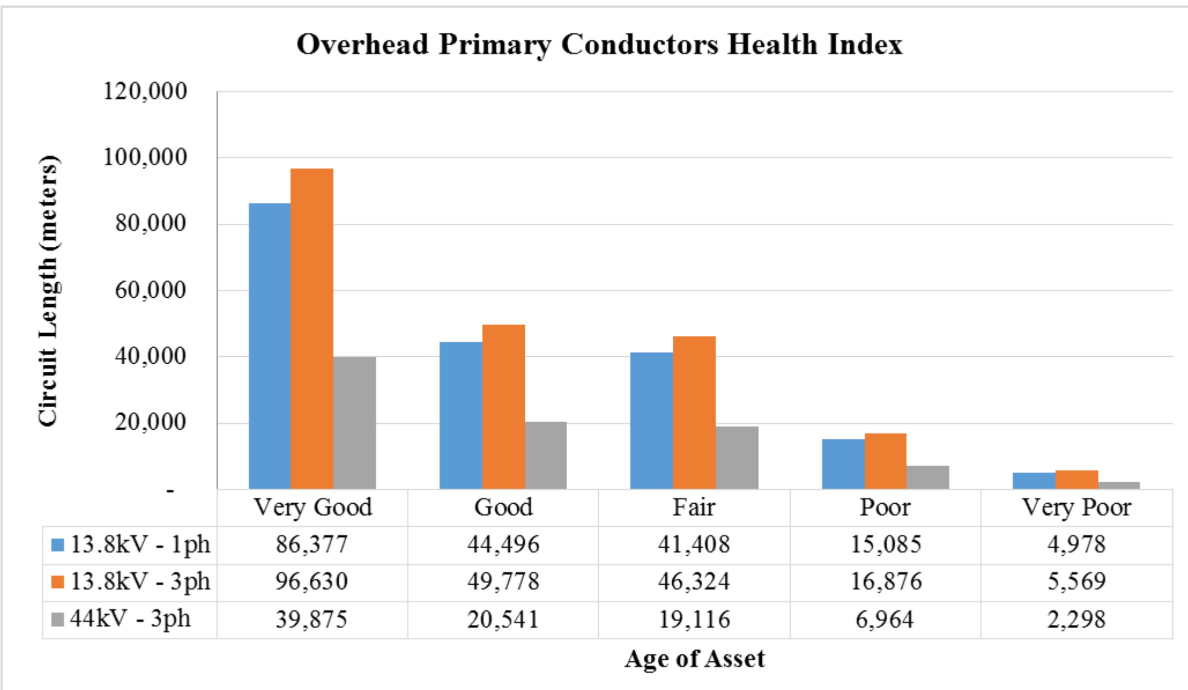
For concrete and steel poles, there were no poles determined to be in "poor" or "very poor" condition. Of the remaining (wood) poles approximately 1,189 were found to be in "poor" or "very poor" condition and in need of replacement within the next 10 years.

OPUCN plans pole testing in 2015, and these "poor" and "very poor" condition poles will be given priority testing to confirm a replacement schedule within the five year planning period. Pending outcomes of the pole tests, OPUCN has included an investment provision of $200 thousand in each of 2016 through 2019 (in the System Renewal category). This provision is based on a forecast of 12 poles needing replacement each year at an average cost of approximately $15 thousand per pole.

Primary Lines

OPUCN's overhead primary distribution network consists of approximately 215 kilometres of 3-ph, 13.8kV, approximately 192 kilometres of 1-ph 13.8kV and approximately 88 kilometres of 3-ph, 44kV lines. Based on the age profile, the heath index score for the conductors is presented in Table 23 below:

Table 23: Health Indices – Overhead Primary Lines



Small size 13.8kV primary conductors (#6 copper)

The current standard requires the 13.8kV lines be constructed with aluminum wires. A majority of the 13.8kV lines constructed during the last 30–35 years in Oshawa are aluminum conductors. However, there are many old 13.8kV lines that are #6 copper conductors still in service, which have low tensile strength, are vulnerable to conductor breakage and thus pose a significant risk to system reliability.

Table 24 and Table 25 show the feeder by feeder breakdown of the circuit lengths of 3-phase and 1-phase lines strung with #6 copper. These lines will need to be rebuilt to current standards with aluminum conductor, to mitigate failure and reliability risks within the next 10 year period. The costs for these line replacements are included in the overhead rebuild projects budgeted in the System Renewal category during the plan period.

Table 24: 13.8kV, 3 phase, #6 copper primary conductors

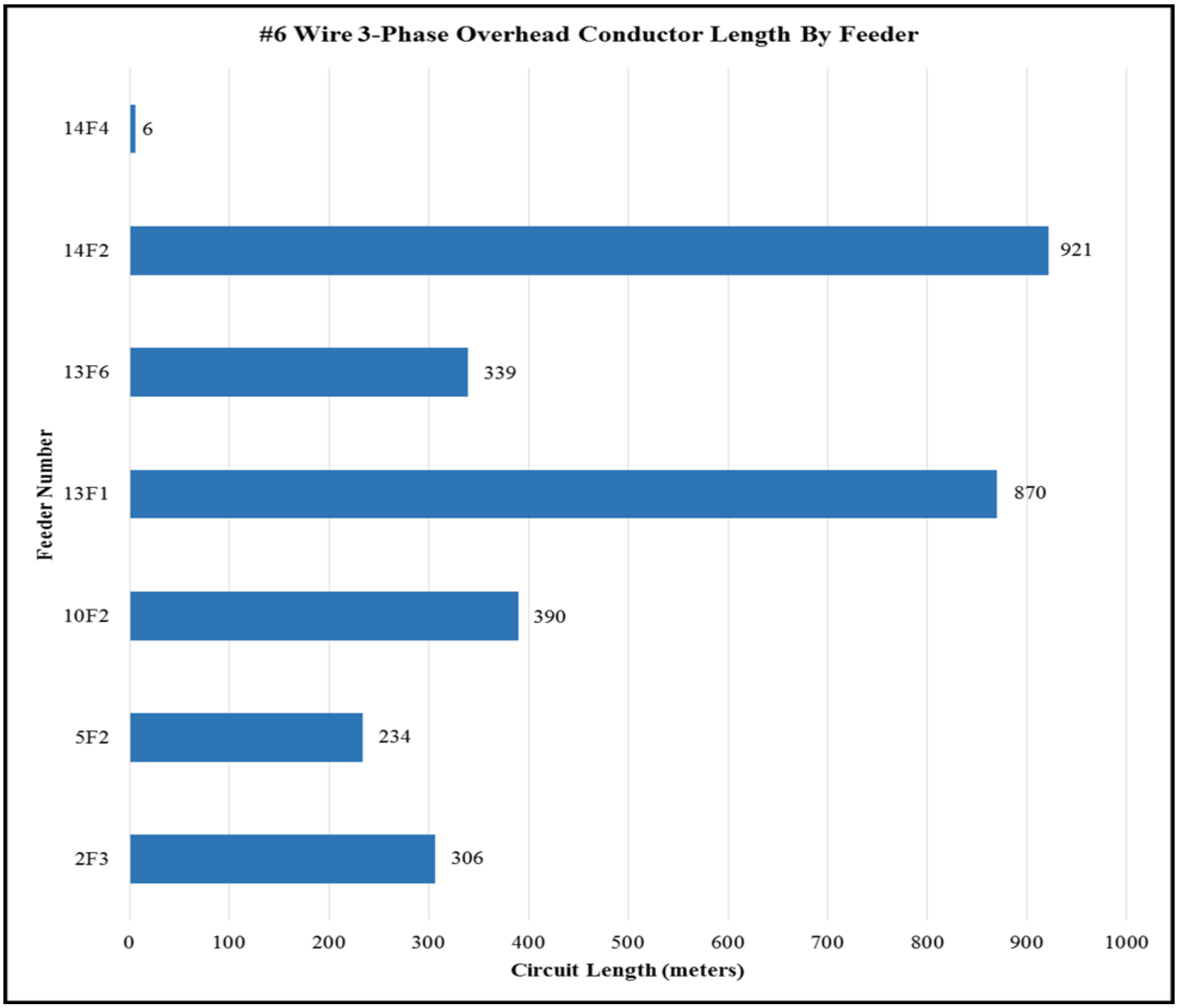
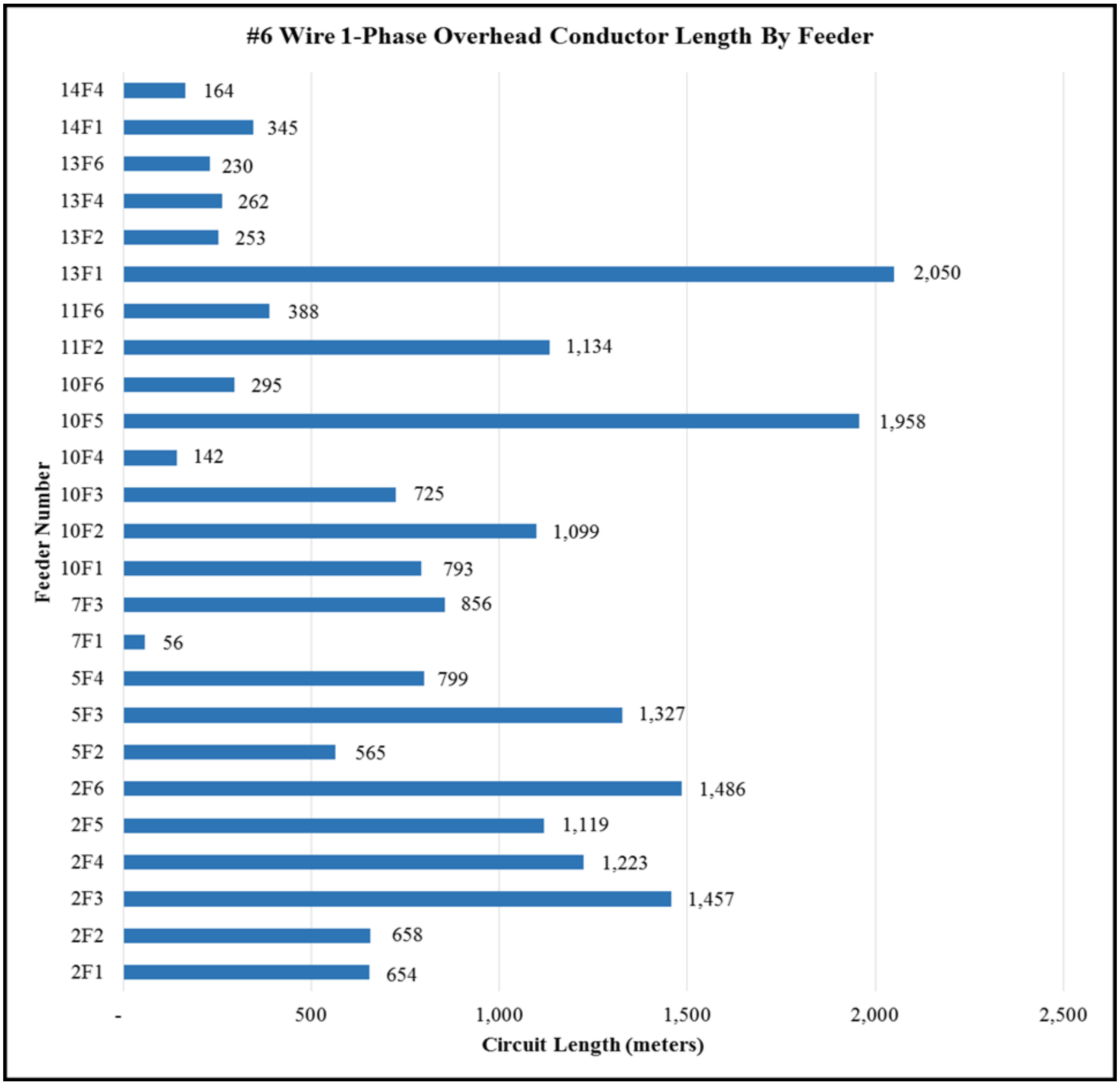


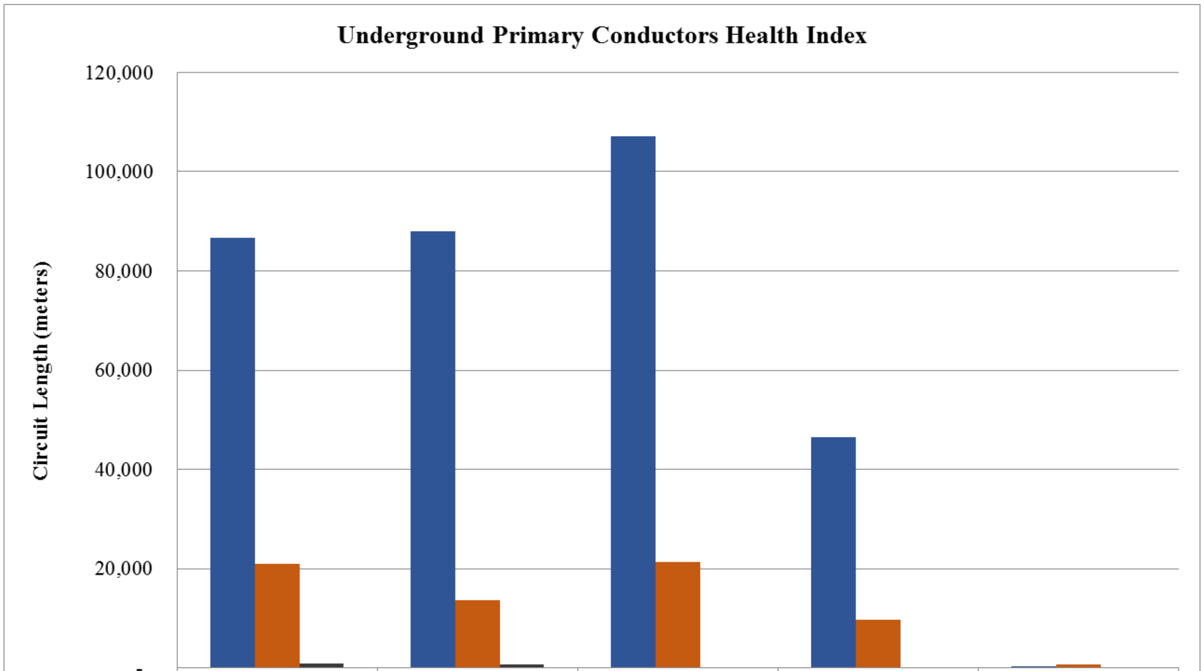
Table 25: Line Lengths of #6 Copper Wire on 1-Phase Overhead Lines



(iv) Underground Distribution Primary Cables

OPUCN's underground distribution network consists of approximately 411 kilometres of primary underground cables with approximately 409 kilometres being 13.8kV underground cables and approximately 1.7 kilometres being 44kV cables. Table 26 indicates the Health Index for these underground primary cables.

Table 26: Health Indices – Underground Primary Cables



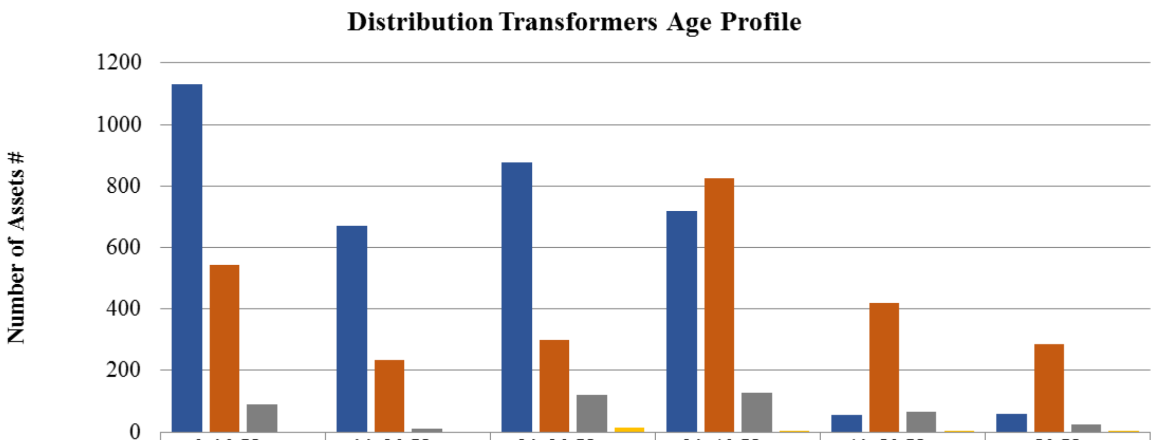
	Very Good	Good	Fair	Poor	Very Poor
13.8kV - 1ph	86,649	88,044	107,131	46,438	330
13.8kV - 3ph	20,870	13,697	21,279	9,627	684
44kV - 3ph	848	691	137	35	62

Approximately 7.5 kilometres of underground cable circuits have a service age of greater than 40 years and approximately 57 kilometres are in “poor” or “very poor” condition. The XLPE cables have a typical useful life of 35 to 40 years, so although the underground cables are not experiencing wide spread failures, unplanned failures are a risk and could significantly impact reliability. It was recommended that OPUCN budget for replacement of the cable circuits with service life of more than 40 years. OPUCN is also prioritizing the replacements of these underground circuits based on the number of failures experienced and assessed as part of its primary underground cable fault analysis. The costs for these cable replacements are included in the underground rebuild projects budgeted in the System Renewal category during the plan period.

(v) Distribution Transformers

OPUCN has approximately 6,571 distribution type transformers. There are four different types of transformers in service: pad-mount, pole-mount, submersible and vault type. Table 27 below reflects the number units of each of these types of transformers in service and the age profile of these units.

Table 27: Distribution Transformers – Age Profile



	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Padmount	1131	669	877	717	55	58
Polemount	542	233	299	825	420	285
Vault Mount	89	12	120	128	65	26
Submersible	0	0	16	1	2	1

OPUCN employs "run-to-failure" strategy for distribution transformers, due to the relatively low impact of transformer failures on reliability. However, when transformers with serious deficiencies are identified through inspections, these are immediately replaced. This strategy is in line with all other LDCs and was supported by METSCO in its report. Costs for such failed asset replacements are included in the $830 thousand annual "reactive" System Renewal cost provision discussed in Part I, Section 2, subsection c.(ii), above (see also Exhibit 2, Tab B, Schedule 7, Attachment E for further detail).

(vi) Switches and Cut-outs Installed in Pole-mounted and Pad-mounted Configurations

OPUCN`s distribution system is well equipped for disconnecting and isolating, load-breaking, and fault interrupting and to provide isolation during power interruptions. A majority of the line switches are pole-mounted. The age data for the overhead switches is not available. The total number of switches is indicated in Table 28. The line switches are generally replaced during reconstruction of a feeder and associated costs are included within OPUCN's feeder replacement projects.

Table 28: Overhead Switches Age Profile

Switch Type	Quantity #
Air Break Type	20
Mid-Span Opener	30
Load Break	44
In Line	508

However, OPUCN had been experiencing repeated failures of porcelain fused switches and insulators during the past three to four years. Some failures have resulted in electrical failure of the insulation, while in other cases the insulator has cracked and broken resulting in pole fires. Although no serious accident has occurred so far, the failing cutouts do present a risk of injury to public or utility employees and have an impact on system reliability.

OPUCN therefore adopted a program under which porcelain switches and insulators are being systematically replaced with polymer type units to address safety risks and improve overall reliability. These replacements started in 2013 and were completed in 2014. Aside from the systematic program, it is expected that additional units will be replaced as part of the overhead rebuild projects during the planning period.

b. *Root Causes of Power Interruptions (2009 - 2013)*

As part of its asset management process, OPUCN conducts a rolling five year root cause analysis of power interruptions. The analysis identifies potential capital upgrades, replacements and new investments necessary for, or supportive of, system and customer service reliability improvements.

The results of the most recent (2009-2013) analysis are summarized in Figure 7 and Table 29. The two predominant causes of OPUCN's historical power interruptions were foreign interference and defective equipment.

The interruptions due to foreign interference are more specifically caused by squirrels climbing on live equipment and bridging the live conductors to grounded plane on older equipment with low electrical clearances. To minimize the squirrel contact incidents with live lines, OPUCN has and continues to install animal guards along with higher voltage (27kV) insulators (as opposed to 15kV insulators) on any new, rebuilt or replacement equipment. The higher voltage insulators provide greater clearance from the lines to the pole and minimize the probability of these bridging incidents.

As shown in Table 29, there are already improvements in reliability as a result of the work completed during the past two to three years.

Figure 7: Root Causes of Power Interruptions

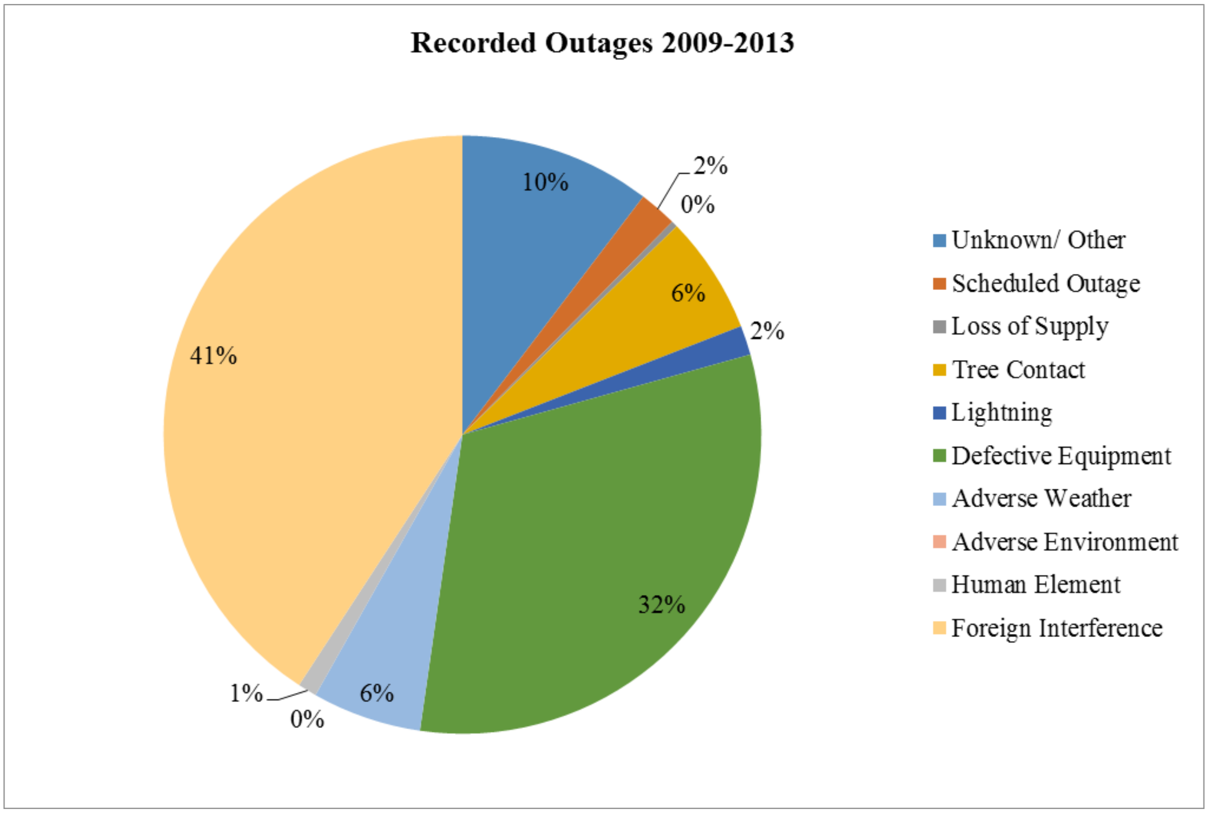


Table 29: Root Causes of Power Interruptions

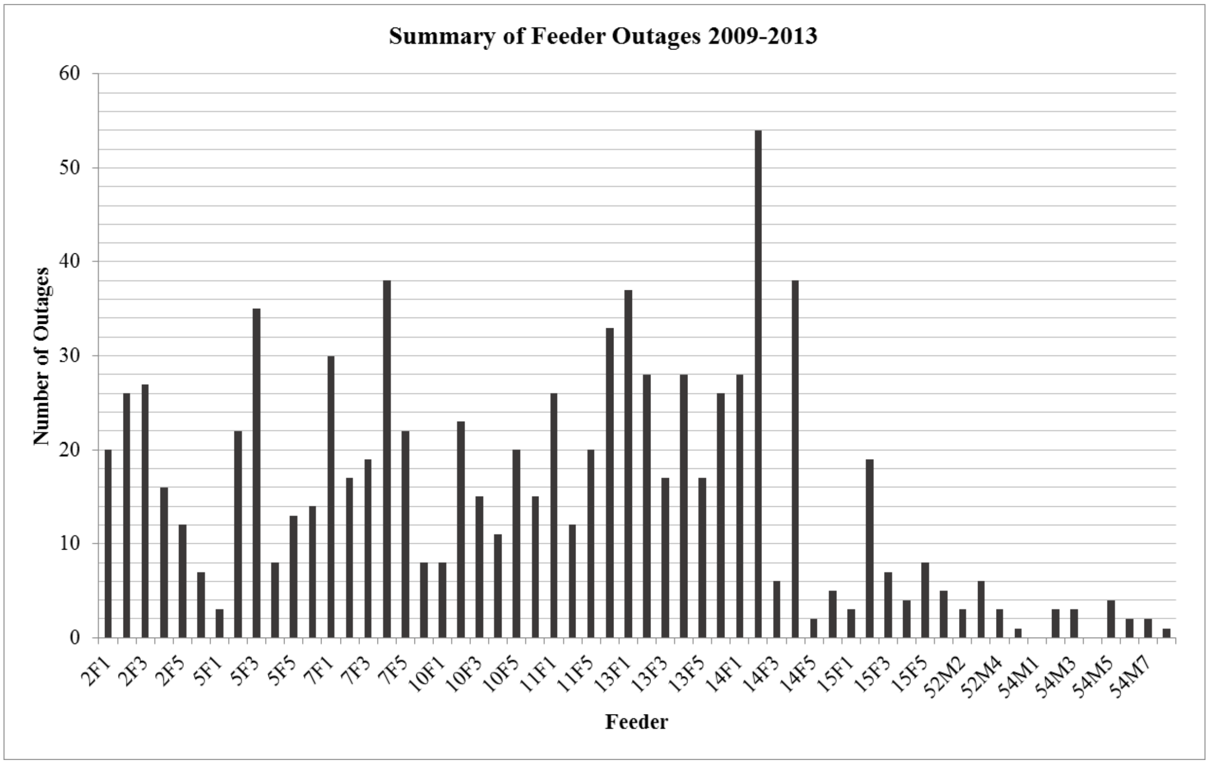
Cause	*Number of Interruptions*				
	2009	**2010**			
Unknown/ Other: Customer interruptions with no apparent cause or reason which could have contributed to the outage.	22	13	9	29	20
Scheduled Outage: Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.	0	0	0	16	2
Loss of Supply: Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.	1	1	0	0	0
Tree Contact: Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.	12	11	8	10	11
Lightning: Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.	5	1	6	2	0
Defective Equipment: Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.	64	53	59	61	48
Adverse Weather: Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.	16	5	7	20	5
Adverse Environment: Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.	0	0	0	0	1
Human Element: Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.	3	1	1	2	2

Cause	*Number of Interruptions*				
	2009	**2010**			
Foreign Interference: Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.	66	71	91	75	59
	189	**156**	**181**	**215**	**148**

Starting in 2011 outages due to defective equipment were increasing primarily due to defective porcelain insulators and switches. As noted above [Section 2, subsection a., item (vi)],test reports indicated that the poorly manufactured porcelain units were failing much faster than the expected life span. A two year program to replace most of the porcelain insulators and switches with polymer type units has been completed.

The most recent root cause analysis also confirmed that interruptions due to faulty or defective equipment are correlated to asset age. The interruptions related to cable faults were analyzed to determine the worst performing feeders. The results of this analysis are summarized in Figure 8, and this information has been used to prioritize the system renewal investments related to the underground primary cable replacements.

Figure 8: Worst Performing Feeders



c. *Renewable Energy Generation (REG) System Capability Assessment*

There are 108 micro-FIT Solar Photovoltaic (PV) installations with micro-FIT generation capacity of 728.8kW and six FIT Solar Photovoltaic (PV) installations with FIT generation capacity of 940kW connected to OPUCN distribution system. In aggregate these distributed generation installations presently have generation capacity of 1,668.8kW.

As shown in Table 30, based on the micro-FIT and FIT applications currently registered with the OPA, there are potentially 32 new Micro-FIT installations with proposed generation capacity of 308.75kW and one new FIT project with proposed generation capacity of 250kW. In addition, there are approximately 11 initial enquiries with OPUCN, totaling potential additional solar generation capacity of 2,960kW.

Table 30: Summary of MicroFit and Fit installations

	micro-FIT (kW)	FIT (kW)	Comments
Connected to OPUCN system	728.8	940	No constraints
Registered with OPA	308.75	250	No constraints
Eleven (11) Initial Enquiries with OPUCN		2,960	Transmission System Constraints

Based on the applications registered with OPA and currently in the review process with OPUCN, there are no anticipated constraints within OPUCN distribution system.

However, due to limitations in short circuit capacity on the HONI system, there are transmission constraints that prevent the connection of any new FIT projects in the Oshawa service area. HONI Transmission proposes the installation of neutral grounding reactors in 2015 at Thornton TS and in late 2015 at Wilson TS DESN1 to mitigate these constraints.

OPUCN does not forecast any renewable energy connection investments on its system from 2015 through 2019.

d. *Grid Modernization Towards a "Smarter Grid"*

As part of its strategy to modernize its distribution system and provide better means of improving overall reliability, resiliency and value to its customers, OPUCN engaged a third party consultant (UtiliWorks) to assess OPUCN's present grid status and to develop a *Smart Grid Roadmap and Financial Analysis* (see Exhibit 2, Tab B, Schedule 4). OPUCN used this roadmap as a guide to prioritizing those recommendations that will most affordably and cost effectively increase efficiencies to its system operations, improve on system outage durations, and minimize outage impact on its customers. Paced and prioritized installation of automated intelligent devices will provide visibility on the "health" and loading of the distribution assets, facilitating automated switching to improve grid efficiency and, as required, restoration time.

For its 2015-2019 Capital Investment Plan OPUCN has adopted those UtiliWorks recommendations that will most affordably and cost effectively increase efficiencies to OPUCN system operations, improve on system outage durations, and minimize outage impact on its customers. The overall capital investment towards a "smarter grid" over the five year planning period is approximately $2.6 million or 4% of the total overall DS Plan.

OPUCN's strategy towards a "smarter grid" also supports its proposed integrated OMS and Mobile Work Force solution, through which OPUCN will be able to use information provided by a "smarter grid" to proactively and automatically contact customers to advise of system outages either related to one customer or to an affected area. Combined with OPUCN's planned OMS (and enhancement and interconnection of related systems), the "smarter" grid which OPUCN proposes to develop over time will enhance OPUCN's ability to communicate with its customers regarding current grid status and, as required, outage and restoration status. Through a web portal associated with the OMS solution, customers will be able to retrieve updated information on the cause and location of an outage and expected restoration time. Through the Mobile Work Force solution, crews closest to the outage can be quickly dispatched achieving operational efficiencies and productivity, along with improved service reliability metrics (SAIDI, SAIFI & CAIDI).

OPUCN's "smarter grid" strategy is also reflected in its proposed investment in remote connect/disconnect and prepaid meter functionality. Further information on this metering investment is provided below in Part VI, Section 3, subsection a.(iv).

3. 2014 – 2019 CAPITAL EXPENDITURE DETAILS

Table 31 summarizes the capital investments included in OPUCN's Capital Investment Plan for the years 2015 through 2019 plus capital expenditures for the 2014 Bridge Year, all aggregated into the four investment categories identified by the OEB in the

Guidelines; a) system access; b) system renewal; c) system service; and d) general plant.

Table 31: Summary of Total Forecasted Capital Investment 2015-2019

	OPUCN PROPOSED CAPITAL INVESTMENTS 2014 - 2019							
		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access	NET EXPANSIONS & CONNECTIONS	*650*	*545*	*560*	*560*	*575*	*585*	2,825
	Total NET 3rd Party Infrastructure Requests - plant relocation cost (407, Region, City)	982	2,804	1,450	1,150	1,150	1,150	7,704
	Total Metering	280	625	630	765	615	615	3,250
	Long Term load transfers (LTLT)	395						0
	Ministry of Energy approved Micro Grid Project	0	110	45				155
	NET TOTAL SYSTEM ACCESS	2,307	4,084	2,685	2,475	2,340	2,350	13,934
	Total Contributions (Expansions & 3rd parties)	1,560	4,911	1,455	1,075	1,095	1,105	9,641
	GROSS TOTAL SYSTEM ACCESS	3,867	8,995	4,140	3,550	3,435	3,455	23,575
System Renewal	OH REBUILDS	2,663	2,410	2,455	2,055	2,510	2,117	11,547
	UG REBUILDS	1,450	1,133	1,007	1,087	921	904	5,052
	STATIONS REBUILDS	1,015	510	640	500	500	1,000	3,150
	Total Planned Plant Rebuilds	5,128	4,053	4,102	3,642	3,931	4,021	19,749
	Reactive/emergency Plant Replacement	830	830	830	830	830	830	4,150
	TOTAL SYSTEM RENEWAL (OH, UG and Stations rebuilds)	5,958	4,883	4,932	4,472	4,761	4,851	23,899
System Services	Total Contributions to HONI for Transmission Capacity		1,500	1,500	1,000	1,000	1,500	6,500
	Total MS9 Substation and Overhead rebuilds for Distribution Capacity	1,930	750	1,000	3,250	3,000	1,000	9,000
	Total Grid Modernization projects	900	618	330	420	645	550	2,563
	TOTAL SYSTEM SERVICES	2,830	2,868	2,830	4,670	4,645	3,050	18,063
General Plant	Fleet	155	420	415	440	190	170	1,635
	Total Facilities Leasehold Improvements	104	225	50	50	50	50	425
	Major Tools and Equipment	40	50	50	50	50	50	250
	Total Operational Capital Projects (OMS, MWF, GIS, MAS, ODS, CIS, IVR Enhancements)	245	850	535	135	160	160	1,840
	Total Office IT Capital Expenditure (software and hardware)	90	130	130	80	280	80	700
	TOTAL GENERAL PLANT	634	1,675	1,180	755	730	510	4,850
	NET TOTAL CAPITAL EXPENDITURES	11,729	13,510	11,627	12,372	12,476	10,761	60,746
	Total Third Party Contributions	1,560	4,911	1,455	1,075	1,095	1,105	9,641
	GROSS TOTAL CAPITAL EXPENDITURES	13,289	18,421	13,082	13,447	13,571	11,866	70,387

As indicated, the net total capital expenditure over the five year (2015 – 2019) period is approximately $60.8 million or an annual average spend of approximately $12.2 million.

The capital investments in each of the Guidelines categories are further described in sections that follow. Capital expenditure details by project are collected and further detailed in Exhibit 2, Tab B, Schedule 7.

a. *System Access Related Capital Expenditure*

(i) Summary and Drivers

Table 32: System Access Related Capital Investment

	OPUCN PROPOSED CAPITAL INVESTMENTS 2014 - 2019							
		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Access	NET EXPANSIONS & CONNECTIONS	*650*	*545*	*560*	*560*	*575*	*585*	2,825
	Total NET 3rd Party Infrastructure Requests - plant relocation cost (407, Region, City)	982	2,804	1,450	1,150	1,150	1,150	7,704
	Total Metering	280	625	630	765	615	615	3,250
	Long Term load transfers (LTLT)	395						0
	Ministry of Energy approved Micro Grid Project	0	110	45				155
	NET TOTAL SYSTEM ACCESS	2,307	4,084	2,685	2,475	2,340	2,350	13,934
	Total Contributions (Expansions & 3rd parties)	1,560	4,911	1,455	1,075	1,095	1,105	9,641
	GROSS TOTAL SYSTEM ACCESS	3,867	8,995	4,140	3,550	3,435	3,455	23,575

The main driver for OPUCN's System Access capital investment program is determined by three essential drivers:

- Forecast of customer connections growing by approximately 15% in the five year period, resulting increase in customer service requests for new or upgraded customer connections and modifications and system expansions for new residential subdivisions, commercial and industrial developments.
- Third party infrastructure developments requiring system plant relocates initiated by the City of the Oshawa, the Region of Durham and the 407 Eastern Construction General Partners (ECGP) responsible for the Highway 407 East extension.

- Mandated Regulatory OEB Changes for MIST meters/revenue metering and Long Term Load Transfers (LTLT) service obligations.

(ii) Customer Connections

With its current population of approximately 157,000, Oshawa is the eastern anchor to the Greater Golden Horseshoe and the Greater Toronto Area. Oshawa is home to a commercial airport and deep water port and is ideally located on the Highway 401 corridor with convenient links to the GTA and eastern communities. Oshawa is home to three highly acclaimed post-secondary institutions; University of Ontario Institute of Technology (UOIT), Durham College and Trent University. In addition, Queen's University School of Family Medicine has established a residency program at Lakeridge Health hospital in Oshawa.

Oshawa was traditionally recognized as an automotive centre of excellence. The city is now continuing to grow as a diverse and innovative city for business, research and education across a variety of sectors including; advanced manufacturing, health and biosciences, energy generation, multimodal transportation and logistics, and information technology.

OPUCN has projected a total net expenditure of $2.8 million for service expansions and connections over the 2015-2019 planning period.

With the extension of Hwy 407, ongoing developments within Oshawa's revitalized downtown core, and the residential and commercial development boom in the north end of the city, OPUCN has seen an increase in, and will continue to receive an accelerating number of, service connection requests for new and upgraded residential infill and subdivision activity and commercial services. Customer connections are forecast to grow by approximately 15% over the five year period.

The City of Oshawa published a 2012 total building permit value of approximately $310 million. In 2013, 1,304 building permits were issued with a total value of approximately

$369 million. The issued permit value for January through September 2014 is approximately $410 million.

Major developments that are driving increased electricity distribution load and consumption are mapped in Exhibit 2, Tab B, Schedule 6 and include the following.

a) **Kedron Part II Subdivision Development:** This development is currently underway, and is one of Oshawa's major new residential communities. It will ultimately house approximately 22,000 people, and it is located between Townline Rd. and Ritson Rd., extending from Conlin Rd. north to Winchester Rd. East. The subdivision development plan spans approximately 1,151 acres and includes residential housing, schools, parks and commercial units. Phase 1 is scheduled to be in service in 2016, with full completion over a 10 year period.

b) **Rio Can:** City Council has approved a commercial development of 2,000,000 sq. ft. at Winchester and Simcoe St. N. In July 2012 the developer obtained subdivision approval for 1.2 million sq. ft. Construction started in 2013 with the first phase in-service date scheduled to coincide with the 407 opening in 2015. Anticipated total load for the completed development is 3MW.

c) **Oshawa Center Expansion:** A $230 million expansion for Oshawa center shopping mall, which is currently underway in Downtown/Midtown Oshawa**.**

d) **Tribute Residential Development:** This development is located in the area of Conlin Rd. and Simcoe St. The developer received preliminary approval for about 800 residential units in June 2013. Housing construction started in 2014 and is ongoing, with strong pre-construction sales continuing.

e) **Minto-Metropia (Kingmeadow) subdivision:** This development located in the area of Conlin Rd. and Simcoe St. is currently under construction. The developer has approval for 1045 residential units, a high school and an elementary school.

f) **Metrus (King Meadow) subdivision:** This project is located east of the Minto/Metropia subdivision and is in the area of Conlin Rd. and Simcoe St. Construction started in 2014. There are about 350 residential units and a school in this subdivision.

For new or upgraded permanent service connections (residential, commercial or industrial), the Distribution System Code (DSC), allows distributors to recover from connecting customers 100% of the basic connection cost defined by the standard allowance, plus any variable connection costs to install connection assets to the point of demarcation, above and beyond the standard allowance. Variable connection assets costs may include the installation of transformers, underground cable, meters and associated equipment.

The DSC also provides that distributors are responsible for and can recover in rates, the cost to complete work on their existing distribution plant initiated by new connection requirements but to the extent that work benefits other customers. OPUCN's share of new customer connection costs has historically averaged approximately $110 thousand per year. This average annual cost has been included in OPUCN's 2015-2019 new customer connections cost forecast.

Cost allocation for subdivisions expansions are based on the OEB's Distribution System Code and OPUCN's Conditions of Service, and related standard applicable economic evaluations for new subdivisions. OPUCN contributes to the cost of the new subdivision's infrastructure using the economic evaluation methodology. Developers are responsible for the cost to complete all civil work, installation of required transformation, switchgear, primary and secondary distribution plan and equipment in accordance with OPUCN's engineering standards and specifications. Economic evaluations conducted by OPUCN for new subdivisions over the period 2010 through 2013 resulted in an approximately 60% contribution from developers towards OPUCN's overall expansion costs. OPUCN is therefore responsible for approximately 40% or approximately $2.3 million over the five year period.

(iii) Third party infrastructure developments

Table 33: 2015-2019 Third Party Infrastructure Request Detail

OPUCN PROPOSED CAPITAL INVESTMENTS 2014 - 2019							
	Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Hwy 407 Extension - Plant relocation GROSS	430	4,510	700				5,210
407 contribution	0	3,580	400				3,980
Hwy 407 Extension - Plant relocation NET	*430*	*930*	*300*				1,230
Durham Region - Plant relocation GROSS	250	1,875	935	1,065	1,080	1,055	6,010
Region Contribution	0	506	235	265	280	255	1,541
Durham Region - Plant relocation NET	*250*	*1,369*	*700*	*800*	*800*	*800*	4,469
City of Oshawa - Plant relocation GROSS	302	680	595	470	460	470	2,675
City contribution	0	175	145	120	110	120	670
City of Oshawa - Plant relocation NET	*302*	*505*	*450*	*350*	*350*	*350*	2,005
GROSS 3rd Party (407, Region , City) Infrastructure Requests - plant relocation	982	7,065	2,230	1,535	1,540	1,525	13,895
Total 3rd party Contribution	0	4,261	780	385	390	375	6,191
Total NET 3rd Party Infrastructure Requests - plant relocation cost (407, Region, City)	982	2,804	1,450	1,150	1,150	1,150	7,704

Over the planning period 2015 – 2019, the total gross expenditure for this category of work is approximately $13.9 million with a net capital expenditure of approximately $7.7 million after contributions of approximately $6.2 million.

In addition to relocation work to accommodate City or Region roadway projects, since late 2012, OPUCN has been implementing plant relocation in response to the 407 expansion project across the top of the City of Oshawa. Unlike in the case of relocation work at the instance of the Region or City, the cost for OPUCN's work related to any plant relocation for the highway extension is 100% recoverable for like for like replacements. Additional or upgraded plant for future system and customer needs is at OPUCN's cost and is planned in accord with standard distribution system planning practices and overall (i.e. longer term) cost efficiencies.

Highway 407 Extension (~Net $1.2 million)

The scheduling of these projects is driven by 407 Eastern Construction General Partners (407 ECGP) schedule to open the Highway 407 extension in two phases.

The first (2015 opening) phase of the 407 extension involves the construction of over and underpasses and highway entry and exit ramps affecting six intersections/locations in Oshawa. This involves three major “clover leaf” crossings, and three additional intersections requiring OPUCN plant installations for future services.

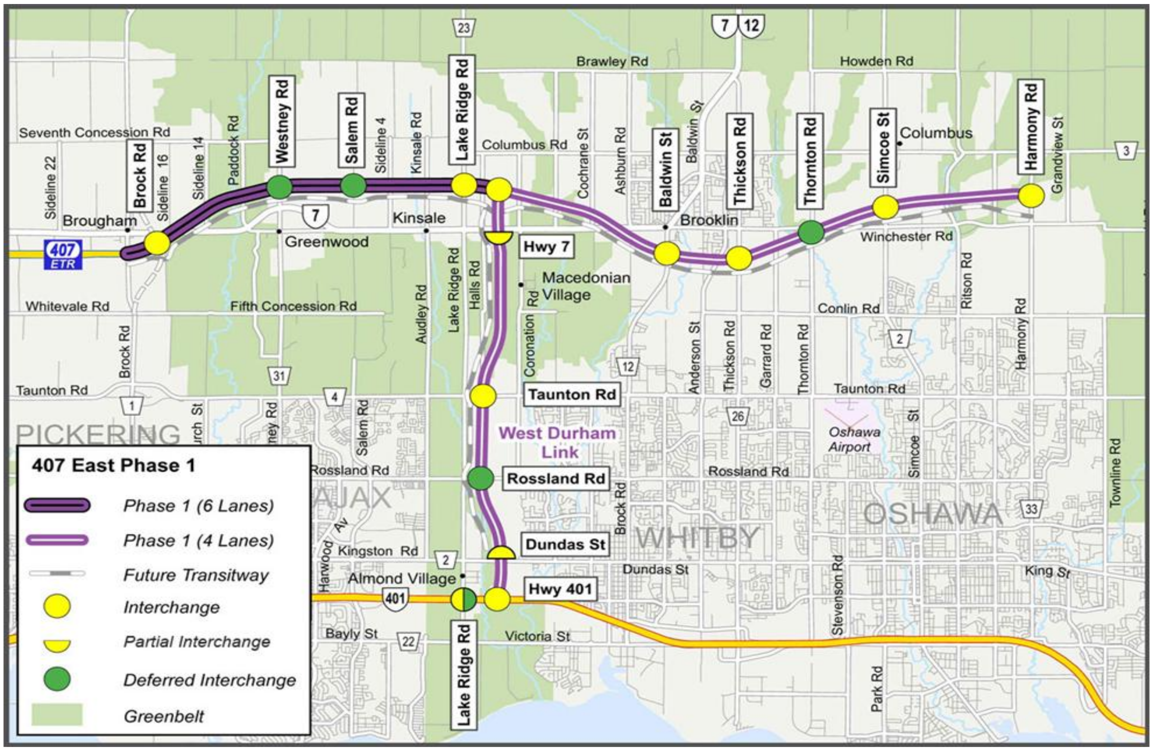
With the anticipated opening of the first phase of the 407 extension in 2015, OPUCN completed temporary relocation of its plant in 2013 to facilitate the construction. The temporary relocation cost was recovered from 407 ECGP. 407 ECGP has begun roadway construction and will include underground infrastructure to convert OPUCN’s existing overhead plant to underground distribution. Due to the nature of this highway construction, it will be prudent for OPUCN to include reasonable additional underground infrastructure to accommodate future load growth/development and avoid any future reconstruction across the new highway. OPUCN capital expenditures in 2015 are forecast to be approximately $930 thousand, and are included in the DS Plan.

OPUCN continues to work closely with 407 ECGP at the six impacted locations in Oshawa, with final restoration or cleanup efforts anticipated in 2015.

A second phase of the 407 extension continuing through North Oshawa is expected in 2016. Upstream work on existing distribution plant in support of both new and existing customer connections over the five years of the planning period is forecast at approximately $300 thousand. This is subject to final 407 ECGP designs.

The maps below (Figures 9 and 10) illustrate the locations impacted by the 407 extension.

Figure 9: 407 East Project Map (Phase 1)[6]



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6 407 East Development Group

Figure 10: 407 East Project Map (Phase 2)[7]

Table 34 below summarizes the total expenditures related to the Highway 407 extension over the 2015-2019 planning period. Further project details are provided in Exhibit 2, Tab B, Schedule 7, Attachment A:

[7] 407 East Development Group

Table 34: Total Expenditures for Highway 407: 2015-2019

	Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS CATEGORY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total 2015-2019**
	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Hwy 407 Extension - Plant relocation GROSS	430	4,510	700				5,210
407 contribution	0	3,580	400				3,980
Hwy 407 Extension - Plant relocation NET	*430*	*930*	*300*				1,230

Region of Durham and the City of Oshawa (~net $6.5 million)

OPUCN receives requests from the Region of Durham and the City of Oshawa for distribution plant rearrangements to accommodate annual roadway reconstruction. In consultation with the regional and municipal authorities, OPUCN forecasts capital expenditures required for such rearrangements.

In accordance with the *Public Service Works on Highways Act*, the requestor (the City or the Region) contributes 50% of the costs of labour and labour saving devices for OPUCN's work in this category. Historically over the 2011 to 2013 period, this has resulted in contributions of approximately 30% of OPUCN gross expenditures in this category.

For the 2015-2019 capital planning period, the forecasted net expenditure for this work is approximately $6.5 million.

In July 2014, the Region experienced a labour dispute and this impacted the work flow from Region's staff. The Region was also having difficulty in securing land rights for some 2014 projects, and this impacted OPUCN's ability to move forward with design and plant relocation work. Some projects that were initially scheduled in 2014 will now be completed in 2015.

The City of Oshawa cancelled a few projects scheduled to be completed in 2014 and made changes in design for another two projects resulting in these projects being carried over to 2015.

Table 35 below summarizes the total OPUCN expenditures related to the Durham Region roadway construction Projects over the planning period:

Table 35: Durham Region Relocations: 2015-2019

	Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS CATEGORY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total 2015-2019**
	$'000	$'000	$'000	$'000	$'000	$'000	$'000
Durham Region - Plant relocation GROSS	250	1,875	935	1,065	1,080	1,055	6,010
Region Contribution	0	506	235	265	280	255	1,541
Durham Region - Plant relocation NET	*250*	*1,369*	*700*	*800*	*800*	*800*	4,469

A more detailed listing of the components of OPUCN's work is connection with Durham Region required relocations is provided in Exhibit 2, Tab B, Schedule 7, Attachment B.

Table 36 below summarizes the total OPUCN expenditures related to the City of Oshawa proposed roadway construction projects over the planning period:

Table 36: City of Oshawa Relocations: 2015-2019

	Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS CATEGORY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total 2015-2019**
	$'000	$'000	$'000	$'000	$'000	$'000	$'000
City of Oshawa - Plant relocation GROSS	302	680	595	470	460	470	2,675
City contribution	0	175	145	120	110	120	670
City of Oshawa - Plant relocation NET	*302*	*505*	*450*	*350*	*350*	*350*	2,005

A more detailed listing of the components of OPUCN's work in connection with City of Oshawa required relocations is provided in Exhibit 2, Tab B, Section 7, Attachment C.

(iv) Mandated Regulated Service Obligations (metering) (~$3.25 million)

This capital investment category includes projects related to metering, long term load transfers and a Ministry of Energy approved micro grid project. Over the planning period 2015–2019, the total expenditure for this category of work is approximately $3.4M. The forecast annual expenditures in this category of work are listed in Table 37.

Table 37: City of Oshawa Relocations: 2015-2019

	Bridge Year	FORECAST PERIOD					
CAPITAL INVESTMENTS CATEGORY	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Total 2015-2019**
	$'000	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
Metering service connections	280	375	380	390	390	390	**1,925**
Remote Disconnect/Reconnect Metering		100	100	100	100	100	500
PrePaid Metering				150			150
OEB's MIST Metering - Interval/smart meters for Accounts >50kW - subject to OEB Req'ts	0	150	150	125	125	125	**675**
Total Metering	**280**	**625**	**630**	**765**	**615**	**615**	**3,250**
Long Term load transfers	395						**0**
Ministry of Energy approved Micro Grid Project	0	110	45				**155**
Total Mandated Service Obligations (Revenue Metering, LTLT)	**675**	**735**	**675**	**765**	**615**	**615**	**3,405**

For the 2015-2019 capital planning period, the forecasted expenditure for metering is approximately $3.25 million. OPUCN has included metering requirements based on the forecasted new and upgraded service connections over the five year period.

Also included in this category (at approximately an additional $1.9 million) are: (i) costs for replacement of defective metering equipment no longer covered by the meter manufacturer warranty; and (ii) costs for the replacement of meters that need to be verified and resealed to comply with Measurement Canada requirements.

To help increase operational efficiencies relating to non-payment billing issues, OPUCN plans to implement smart meters with automated disconnect and reconnect functionality that will eliminate the need for technicians to attend to these activities. The new meters will enable OPUCN to service its planned customer growth without a commensurate increase in resources and operating costs. Estimated avoided costs for technician services is over $100,000 per year. These “efficiencies” are already embedded in OPUCN’s operations planning. OPUCN projects a capital investment of approximately $500 thousand over the five year plan period. This “smart grid” related initiative is one of the recommendations in the UtiliWorks report (see discussions at subsection c.(ii), below).

In 2017, OPUCN plans to implement a pre-paid metering program for certain residential customers with historic payment issues. With these systems affected customers will be able to pay in advance and have a credit put into the system. A pre-paid metering system benefits the customer by giving the customer control of their electrical usage spending while allowing the utility to be paid in advance for future usage by those customers and thereby avoid bad debt costs. It is anticipated that this approach will mitigate the number of customers included in OPUCN's "bad debt category" and will thereby avoid future bad debt and related operational costs. The anticipated 2017 expenditure is approximately $150 thousand. This is another of the "smart grid" related initiatives recommended in the UtiliWorks report (see discussion at subsection c.(ii) below).

Effective August 21, 2014, utilities are required by 2020 to upgrade all General Service customers >50KW currently not interval metered to interval meters. In Oshawa, there are approximately 500 existing meters that need replacement and this is scheduled to be completed before 2020. The 2015–2019 anticipated expenditure for these replacements is approximately $675 thousand, including the costs of the removed meters.

In 2015 and 2016 OPUCN's capital investment plan includes costs of $150 thousand for participation in a Ministry of Energy approved micro-grid pilot project.

The Ministry of Energy's Smart Grid initiative encourages utilities to pilot new "smart grid" technologies and test them for grid impact.

OPUCN believes in the development of renewable energy resources and distributed generation that will provide greater flexibility, uninterrupted power supply and environmental impact reduction. The OPUCN micro-grid demonstration project is in collaboration with University of Ontario Institute of Technology (UOIT), Panasonic, G&W Canada and OPUCN, with Panasonic being the lead participant. The project will utilize and integrate an existing CHP installation, planned solar installation and battery storage solution to create a micro-grid that will operate in parallel with OPUCN's distribution system and be capable of "islanding" when the OPUCN's LDC electrical supply is disconnected. OPUCN's contribution to this project is its labour in kind.

b. *System Renewal Related Capital Expenditure*

(i) Summary and Drivers

Table 38: System Renewal – 2014 to 2019 Capital Expenditure

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Renewal	OH REBUILDS	2,663	2,410	2,455	2,055	2,510	2,117	**11,547**
	UG REBUILDS	1,450	1,133	1,007	1,087	921	904	**5,052**
	STATIONS REBUILDS	1,015	510	640	500	500	1,000	**3,150**
	Total Planned Plant Rebuilds	**5,128**	**4,053**	**4,102**	**3,642**	**3,931**	**4,021**	**19,749**
	Reactive/emergency Plant Replacement	830	830	830	830	830	830	**4,150**
	TOTAL SYSTEM RENEWAL (OH, UG and Stations rebuilds)	**5,958**	**4,883**	**4,932**	**4,472**	**4,761**	**4,851**	**23,899**

The main driver for this investment category is maintaining a high level of system reliability and thus customer value and service. Operational safety and flexibility resulting from upgrading legacy equipment with new technology are additional benefits flowing from these investments.

System renewal investments involve the replacement or refurbishment of system assets identified as being at or near the end of their useful service life. This allows OPUCN to maintain electricity services to its customers at an optimal level of reliability. Investments in this category include proactive replacement of assets nearing the end of their service life where the risk of an asset's in service failure is unacceptable, along with reactive expenditures for replacement of assets that fail in service.

The intent for proactive replacements is to mitigate a more adverse impact to customers due to unplanned asset failure in the field (manage risk and reliability) and hopefully reduce emergency replacements, improve operational efficiencies and lower costs. Through its asset condition assessment work, OPUCN has identified the level of system renewal capital expenditure to best secure system reliability and customer satisfaction, minimize operational and maintenance costs and improve value to customers.

System renewal projects involve overhead plant rebuilds, underground plant rebuilds and stations rebuilds.

OPUCN has attempted to smooth its year over year capital investment profile by scheduling projects based on criticality and impact to system and customer reliability, while balancing its ability to practically complete the volume of projects and mitigating rate impact to its customers.

As described in Part III, Section 4 above, comparison of OPUCN's forecast average net fixed assets per customer in 2019 is $1,813, which remains below the average for comparable LDCs in 2013. This validates that OPUCN's capital investments program remains prudent and reasonable over the plan period.

(ii) Project Details

Overhead Rebuilds

Total overhead capital investment is approximately $11 million or an annual average of approximately $2.2 million.

As identified in the ACA prepared by METSCO (Exhibit 2, Tab B, Schedule 3), OPUCN has an aged infrastructure consisting of old 13.8kV, #6 copper conductors that are still in service and require replacement. Along with replacement of these conductors, poles that are over 35 or 40 years with associated distribution components of similar age, and outdated porcelain insulators and switches need to be upgraded to meet current standards.

Details of the components of OPUCN's 2015-2019 overhead rebuild program are provided in Exhibit 2, Tab B, Schedule 7, Attachment D.

Underground Rebuilds

Total underground asset capital investment is approximately $5 million.

As identified in the ACA, OPUCN has an aged infrastructure consisting of old #2 cu primary cables in subdivisions or townhouse complexes located in the older parts of Oshawa, and which have experienced multiple feeder outages and in general have an underground infrastructure that is over 35 to 40 years old. Replacement of these conductors and associated underground infrastructure is required.

Details of the components of OPUCN's 2015-2019 underground rebuild program are provided in Exhibit 2, Tab B, Schedule 7, Attachment E.

Station Rebuilds

The total capital investment over the 2015–2019 for necessary distribution station rebuilds is approximately $3.2 million.

Table 39 lists the projects in this investment category that exceed the materiality threshold. As with the overhead and underground asset rebuild programs, the distribution station projects included in this DS Plan are required to address risks of asset failure due to end of useful life or outdated equipment standards.

Table 39: Station Rebuilds: 2015-2019

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
SYSTEM RENEWAL							
STATIONS REBUILDS - Assets at EOL, Failure Risks, legacy standards, obsolete, Reliability impacts							
Substation Breaker Replacement Program (2011-2016)	Replace Main Vacuum Breakers with SF6 FPE DST2 Main and Westinghouse bus tie - Replace legacy installations with Improve technology	$175	$210	$140			
MS5 T1- Replace 25kVA Power Transformer including Oil Containment -TX out of service - disolved gas results critically high	Replace Power transformer 40+ yrs, with new 25kVA Tx unit c/w Oil Containment - Unit presently out of service	$840					
MS14 - Metalclad Switchgear - accelerated corosion -	Relaibility Replace outdoor switchgear, reached end of life Replace with Arc Flash resistance type		$300				
MS5 T2- Replace 25kVA Power Transformer including Oil Containment	Unit 30 yrs - Identified needed replacemnent as in poor condition based on tests - approaching end of life - Reliability						$1,000
44kV oil circuit breakers replace with SF6 in Outdoor enclosure. Start in 2016 with 4 breakers per year.	Obsolete, end of life 45+ years breaker counter defective - total 12 OCB in the system to be replaced			$500	$500	$500	
	TOTAL STATION REBUILDS	$1,015	$510	$640	$500	$500	$1,000

Further details of the components of OPUCN's 2015-2019 station rebuild program are provided in Exhibit 2, Tab B, Schedule 7, Attachment F.

c. *System Service Related Capital Expenditure*

(i) Summary and Drivers

Table 40: Summary of System Service Investments

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Services	Total Contributions to HONI for Transmission Capacity		1,500	1,500	1,000	1,000	1,500	6,500
	Total MS9 Substation and Overhead rebuilds for Distribution Capacity	1,930	750	1,000	3,250	3,000	1,000	9,000
	Total Grid Modernization projects	900	618	330	420	645	550	2,563
	TOTAL SYSTEM SERVICES	2,830	2,868	2,830	4,670	4,645	3,050	18,063

The bulk of the investment in this category is required to resolve transmission and distribution capacity constraints due to the projected load growth in Oshawa. This investment is required to support system access requests and maintain service delivery to both new and existing customers.

This category also includes incremental capital investment for grid modernization, to improve system operations, reliability and efficiencies through automation and intelligent equipment. These investments will also help OPUCN move forward towards a “smarter grid” and be in a better position to meet future customer service requirements.

Table 41 provides a more detailed view of the planned investments in this category above the materiality threshold.

Table 41: System Services Expenditures: 2015-2019

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
System Services	**Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension**	1,930						
	Capacity investment (Thornton TS, Wilson TS- subject to Regional Planning) & MS9							
	Thorton TS Capacity - HONI Contributions		1,500	1,500				3,000
	Wilson TS Capacity - HONI Contributions				1,000	1,000	1,500	3,500
	Total Contributions to HONI for Transmission Capacity		**1,500**	**1,500**	**1,000**	**1,000**	**1,500**	**6,500**
	MS9 - 44kV/13.8kV Substation		750	1,000	3,250	2,000		**7,000**
	MS9 Proposed OH distribution feeders					1,000	1,000	**2,000**
	Total MS9 Substation and Overhead rebuilds for Distribution Capacity	**1,930**	**750**	**1,000**	**3,250**	**3,000**	**1,000**	**9,000**
	Total Transmission and Distribution Capacity	**1,930**	**2,250**	**2,500**	**4,250**	**4,000**	**2,500**	**15,500**
	Grid Modernization - Operational projects - For Safety, Efficiency, Reliability & Power Quality Improvements							
	Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements *[UtiliWorks Smart Grid Report Pg 23 & 11]*	900	548	280	10	10	10	**858**
	Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years) *[UtiliWorks Smart Grid Report Pg 23 & 11]*				350	350	255	**955**
	Smart Fault Indicators *[UtiliWorks Smart Grid Report Pg 23 & 11]*		25	25	25	25	25	**125**
	Volt-Var optimization & Reduction in Distribution Losses *[UtiliWorks Smart Grid Report Pg 22 & 11]*	0	0	0	0	225	225	**450**
	Distribution System Supply Optimization (Transmission management) *[UtiliWorks Smart Grid Report Pg 25 & 11]*		45	25	35	35	35	**175**
	Total Grid Modernization projects	**900**	**618**	**330**	**420**	**645**	**550**	**2,563**
	TOTAL SYSTEM SERVICES	**2,830**	**2,868**	**2,830**	**4,670**	**4,645**	**3,050**	**18,063**

The anticipated growth in customer connections and peak load on OPUCN's system is reviewed in Part I, Section 2., subsections b.(i) and b.(ii).

(ii) Project Details

Based on these projected loadings a “Needs Screening” report was prepared by the GTA East Region Study Team as part of the new Regional Planning Process. The “Needs Screening” report confirms the following results:

- **Wilson TS T1/T2 DESN1 (230/44kV)**

  Wilson TS DESN1 is forecast to exceed its normal supply capacity from 2018 to the end of the study period (approximately 101% and 117% of Summer 10-Day LTR in 2018 and 2023 respectively). Transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs.

- **Wilson TS T3/T4 DESN2 (230/44kV)**

  Wilson T3/T4 DESN2 is forecasted to exceed its normal supply capacity from 2014-2023 for both the gross and net demand forecasts (approximately 124% and 115% of Summer 10-Day LTR for gross and net forecasts respectively in 2014 and 140% and 107% for gross and net forecasts respectively in 2023).

  Transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs. In the past, overloading at Wilson TS DESN2 under certain conditions was significant enough that emergency rotating load shedding was required.

- **Thornton TS T3/T4 (230/44kV)**

  From 2015 to the end of the study period, Thornton TS is forecast to exceed its normal supply capacity based on the gross and net demand forecast (approximately 114% and 110% of Summer 10-Day LTR for gross and net forecasts respectively in 2018 and 118% and 109% for gross and net forecasts respectively in 2023).

  Transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs.

  Currently, capacity of the Thornton T3/T4 transformers has been limited to their continuous rating since they have been identified as gassing. Hydro One is scheduled to replace both of these transformers in 2015 with two new 75/100/125 MVA transformers.

As part of the Regional Planning process both station and feeder capacity constraints at Thornton TS and Wilson TS were identified as being best addressed through local planning discussions. Discussions are still in progress with respect to transmission station capacity and feeder utilization constraints including potential solutions. Contributions of $6.5 million to HONI for the costs of these solutions are included in this DS Plan, as discussed in further detail in Part II, Section 3, above.

MS9 Substation

In addition to anticipated contributions to address transmission capacity constraints, OPUCN needs to construct a new substation by 2019 to have distribution capacity and facilities ready to service projected customer growth in the north end of Oshawa.

Although there is a risk that the load may not materialize in full or at the pace projected by the City of Oshawa, present volumes of building permits issued (as of September 2014, approximately $410 million in value), along with the increased amount of new subdivision expansions and connection requests received by OPUCN, demonstrates that the growth is so far materializing as forecast. Given the proposed in service dates for active developments and their phased completion, OPUCN is confident that the new substation (MS9) is required and that the design and construction needs to start in 2015, so as to ensure sufficient capacity is available.

The proposed location of the new municipal substation MS9 is at the south east corner of Wilson Rd. and Conlin Rd. The design and construction of these facilities is expected to take three to four years, commencing in 2015. The estimated cost for these distribution facilities is approximately $9 million.

Further details of the components of OPUCN's System Service system capacity driven projects for 2015-2019 are provided in Exhibit 2, Tab B, Schedule 7, Attachment G.

Grid Modernization

System Service expenditures also include investments in grid modernization that will enhance customer value including enhanced system reliability and resilience. This will involve distribution automation, intelligent devices and software applications to mitigate customer impact of system outages, reduce system restoration time and improve customer communication.

OPUCN engaged UtiliWorks to assess OPUCN's present grid status and develop a *Smart Grid Roadmap and Financial Analysis*. OPUCN used this roadmap as a guide to prioritizing those recommendations that are cost effective, reasonable and practical, that will increase efficiencies to its system operations, improve n system outage durations, and minimize impact to its customers.

Table 42 lists the grid modernization projects prioritized by OPUCN for implementation within the 2015-2019 plan period.

Table 42: Grid System Service Grid Modernization Projects: 2015-2019

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM SERVICE							
UG Distribution Automation Project - Phase 1 - Downtown Vaults Automation (including Bell Vault) from 2013 [*Grid Modernization - UtiliWorks Smart Grid Report pg 23 & 11*]	Remote 8 UG automated switches, fibre for communications and control, all tied into SCADA (Total Phase 1 project estimate approx $650K not completed; $400K carried over)	**$400**					
UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (Avanti, Carriage House, Michael Starr, CIBC, PHI Office, William Vaults) *[Grid Modernization - UtiliWorks Smart Grid Report pg 23 & 11*]	Remote 6 UG automated switches, fibre for communications and control, all tied into SCADA	**$500**					
UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (CIBC Vault and Michael Starr) **Carried over from 2014** *[Grid Modernization - UtiliWorks Smart Grid Report pg 23 & 11* **]**	Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching		**$110**				
UG Distribution Automation Project - Phase 3 - Downtown Vaults Automation (Durham Tower, Bond Towers McLaughlin Square Vaults) *[Grid Modernization - UtiliWorks Smart Grid Report pg 23 & 11]*	Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching		**$438**				
UG Distribution Automation Downtown vaults Phase 4 - Self Healing sytem using remote automated switching and intelligent software application *[Grid Modernization - UtiliWorks Smart Grid Report Pg 23 & 11*]	Self Healing UG grid - Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching			**$280**	**$10**	**$10**	**10**
OH Distribution Automation Self Healing Intellirupters switches (8 feeders 13 switches over 3 years - 5 switches in phase 1 & 2 with 3 in Phase 3. *[Grid Modernization - Pg 23 &11 of UtiliWorks Smart Grid Report]*	Self Healing OH grid - Continue with installation of self healing Intellirupters switches for Overhead automation to reduce restoration time, minimize outage duration and Improve Reliability through remote intelligent devices and switching				**$350**	**$350**	**255**
Voltage Monitoring (Volt Var Optimization and Reduction in Distribution Losses) *[UtiliWorks SmartGrid Report Pg 22 &11]*	Voltage communication devices, substation controls and management system (Volt var Optimization					**$225**	**225**
Grid Modernization/Smart Grid related MISI Projects UNDER MATERIAL THRESHOLD *[Utiliworks Smart Grid Report Pg 25 & 11]*	Smart fault indicators and Transmission management system (Pg 25 & 11 of UtiliWorks Report - mitigate system peak loads)		**$70**	**$50**	**$60**	**$60**	**60**
	TOTAL SYSTEM SERVICE	**$2,830**	**$2,868**	**$2,830**	**$4,670**	**$4,645**	**$3,050**

Details of each of these projects are provided in Exhibit 2, Tab B, Schedule 7, Attachment H.

d. *General Plant Capital Expenditures*

(i) Summary and Drivers

Table 43 below summarizes the planned capital expenditure in the General Plant investment category. The total expenditures over the five year planning period are approximately $4.9 million.

Table 43: General Plant Capital Expenditure

		Bridge Year	FORECAST PERIOD					
	CAPITAL INVESTMENTS CATEGORY	2014	2015	2016	2017	2018	2019	Total 2015-2019
		$'000	$'000	$'000	$'000	$'000	$'000	$'000
General Plant	Fleet	155	420	415	440	190	170	1,635
	Total Facilities Leasehold Improvements	104	225	50	50	50	50	425
	Major Tools and Equipment	40	50	50	50	50	50	250
	Total Operational Capital Projects (OMS, MWF, GIS, MAS, ODS, CIS, IVR Enhancements)	245	850	535	135	160	160	1,840
	Total Office IT Capital Expenditure (software and hardware)	90	130	130	80	280	80	700
	TOTAL GENERAL PLANT	634	1,675	1,180	755	730	510	4,850

These investments are driven by operational and business objectives to achieve an improved and safe work place, increase efficiencies and productivity, and enhance customer service and value. For the most part, assets in this category are reaching or are at end of life and costs for maintenance or repair and associated productivity loss are increasing. Staff must also have the right tools in good working condition to perform their tasks safely. IT systems, both software and hardware, must be regularly upgraded to maintain functionality for today's business requirements. Finally, the proposed Outage Management System (OMS) will help OPUCN better manage its distribution grid and move towards providing the level of communication expected by customers during outage conditions.

(ii) Project Details

Fleet

Fleet expenditures include the replacement of vehicles that are approaching end of useful life and undergo frequent or high maintenance, have difficulty starting or become a high risk when in use.

In order to sustain its fleet, reduce maintenance and operation costs and hence improve operational efficiencies, for 2015 through 2019, OPUCN proposes the following replacements:

- 2015: One station van, two cube vans (for metering) and one trailer for pole delivery
- 2016: One single 46 ft. single bucket truck and one extended pickup truck
- 2017: One single 46 ft single bucket truck, one extended pickup truck, and one trailer for wire delivery
- 2018: Four extended pickup trucks and two dump trucks
- 2019: One cube van, one extended pickup truck, and one trailer for wire delivery

Facilities

Annual expenditures of $50,000, based on historic trend, are proposed to cover leasehold improvements at the head office or work center facilities. In addition to these sustaining annual expenditures, in 2015, OPUCN plans to invest an incremental $175 thousand in 2015:

a) for improvements in the Design Technicians' building to install an additional work station and an additional woman's washroom facility. Currently there is one washroom in this building to serve 10 men and five women.

b) to leverage the space in the pole yard to house cable reels and other material currently housed in the head office parking lot. OPUCN in 2015 plans to build a secure monitored housing in its pole yard for these cable reels and other material and equipment. Storage in this new outdoor secured area will allow for, additional parking spaces for planned additional personnel.

Major Tools and Equipment

The need for new and replacement tools and equipment is essential to perform jobs safely and efficiently. Annual expenditure of $50,000 is based on historic trend for replacements.

Outage Management System

OPUCN plans to implement an Outage Management System (OMS) to have better visibility on the occurrence of system or customer outages and to improve its communication to its customers on which are areas are experiencing an outage, how many customers are affected, and the anticipated outage response and restoration time, all in order to enhance overall customer satisfaction. Customer preferences for investments to improve restoration time and provide updated information on outages was evident in the results of the Utility*PULSE* customer surveys discussed in Part II, Section 1.

The OMS will integrate with OPUCN's GIS, SCADA, CIS and AMI Smart Meters with the objective of improving reliability through automated detection of fault and reduced response and restoration time.

OPUCN will be able to proactively and automatically contact customers to advise of system outages either related to one customer or an affected area. Similarly, through a web portal associated with the OMS, customers will have ability to retrieve updated information regarding the cause and location of an outage and expected restoration time.

Total estimated project cost over the two year period 2014-2015 is approximately $925,000.

Mobile Work Force (MFW)

OPUCN is also planning to implement a Mobile Work Force (MFW) solution so that crews closest to an outage can be quickly dispatched, enhancing operational efficiencies and productivity. This is planned after the OMS is operational, and then this overall integrated solution will support further improvements in the service reliability metrics (SAIDI, SAIFI & CAIDI). Total plan period costs for the MFW are $100,000, and are included in the “Total Operational Capital Projects” line on Table 43.

Major IT server Replacement in both production and DRP site

OPUCN has identified servers that were originally deployed in 2011 and which will reach end of life in 2018. IBM will not sell or provide maintenance on those devices that have reached end of life cycle. Normally recommended hardware retirement policy/practice is five years since the cost of maintenance at years six and seven combined is almost the same as purchasing the new equipment. Total forecast costs for replacements are $200,000, slated for 2018.

Further detail on OPUCN’s forecast General Plant capital investments for the period 2015-2019 are provided in Exhibit 2, Tab B, Schedule 7, Attachment I.

OPA Letter of Comment

Oshawa PUC Networks Inc.

Renewable Energy Generation Investments Plan

December 17, 2014

ONTARIO POWER AUTHORITY

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Oshawa PUC Networks Inc. – Distribution System Plan

On December 12, 2014 Oshawa PUC Networks Inc. ("OPUCN") provided its Renewable Energy Generation Investments Plan ("Plan") to the OPA as part of its 5-year Distribution System Plan. The OPA has reviewed OPUCN's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

On page 2 of its Plan, OPUCN indicates that it has connected 108 microFIT projects totalling 728.8 kW of capacity, and 6 FIT projects totalling 940 kW of capacity. In addition to projects that have been connected to its distribution system, OPUCN also indicates that, based on current microFIT and FIT applications registered with the OPA, it has potentially 32 microFIT installations totalling 308.75 kW of generation capacity, and 1 FIT project of 250 kW of proposed generation capacity that may require connection.

According to OPA's information, as of October, 2014, the OPA has offered contracts to 102 microFIT projects, totalling approximately 673 kW of capacity that remain active to date. As well, the OPA has offered contracts to 6 FIT projects totalling 940 kW of capacity that are still active.

The OPA finds that OPUCN's Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date. The slight disparity in the number of connections reported by OPUCN and the OPA is likely the result of different dates of data collection. It is noted that the 250 kW FIT project that was registered with the OPA, and that had not yet achieved commercial operation, has since been terminated.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

On page 6 of its Plan, OPUCN indicates it is proposing no future capital investments to accommodate the connection of future potential microFIT installations over the next five years from 2015 to 2019. Further, OPUCN indicates that it is not able to determine the need for any capital expansions or enhancements on its distribution system over the next five years with respect to any future FIT projects. The OPA therefore has no comment on the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments.

The OPA notes that OPUCN has participated in planning meetings with OPA and Hydro One as one of the LDCs within the GTA East Region. Through this participation, OPUCN affected the reprioritization of East GTA from a "Group 2" to a "Group 1" Region. This reprioritization meant that the regional planning process was initiated in 2014. The reprioritization was granted in light of transmission capacity issues at OPUCN's Wilson TS and Thornton TS, and has been confirmed by Hydro One in a Planning Status letter to OPUCN. On August 11, 2014, GTA East Needs Screening report was published by Hydro One.

The Needs Screening report recommended that for the needs identified within OPUCN's service territory, specifically related to station capacity needs at Wilson TS and Thornton TS, no further regional coordination is required, and that these needs can be adequately and efficiently addressed by Local Planning between Hydro One Networks Inc. and the relevant LDCs.[1] The OPA has completed the Scoping Assessment phase for the East GTA Region, which confirms the findings of the Needs Screening Report. The Scoping Assessment identified the Pickering-Ajax-Whitby area as a sub-region of GTA East for an Integrated Regional Resource Plan, which covers the western portion of GTA East region, and is outside of OPUCN's franchise service territory.

The OPA appreciates the opportunity to comment on the information provided as part of OPUCN's Distribution System Plan.

[1] Needs Screening Report, Region: GTA East, dated August 11, 2014:
http://www.hydroone.com/RegionalPlanning/GTA_East/Documents/Needs%20Screening%20Report_GTA%20East%20Region_August%2011%202014%20(Final).pdf .

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December 12, 2014

Ms. Denise Flores
Vice President, Engineering and Operations
Oshawa PUC Networks Inc.
100 Simcoe Street South
Oshawa, Ontario L1H 7M7

Via email: dflores@opuc.on.ca

Dear Ms. Flores**:**

Subject: GTA East Regional Planning Status

This letter is in response to your request for an updated Planning Status letter.

The province has been divided into 21 Regions for the purpose of regional planning. These 21 Regions are assigned to one of 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively.

Hydro One Networks Inc. is a lead transmitter in 19 Regions and your Local Distribution Company (LDC) belongs to the GTA East Region. Prior to the new regional planning process coming into effect in August 2013, planning activities were already underway in the Region to address some specific station capacity needs. This Region was subsequently expedited at the request of the affected LDCs and reprioritized from Group 2 to Group 1.

Group 1 – GTA East Region

The Needs Screening assessment for the GTA East Region is complete. It was published on Hydro One's Regional Planning website on August 11, 2014 in accordance with the regional planning process as set out in the OEB's Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board"[1].

[1] Planning Process Working Group (PPWG) Report to the Board – May 17, 2013

As mentioned earlier, prior to the new regional planning process, planning activities were already underway to address some of the specific connection capacity needs in the GTA East Region, with participation from the relevant LDCs, Hydro One Networks Inc. (Hydro One), and Ontario Power Authority (OPA). In particular, to address OPUCN's capacity needs at Wilson TS and Thornton TS, existing feeder capacity utilization at the two stations was first considered. The resulting option was the addition of two new feeder breaker positions at both stations. OPUCN's cost for this work was estimated to be approximately $6.5 million, which I understand is included in your budget and upcoming Rate Filing Application.

Notwithstanding, as noted in the recent Needs Screening report dated August 11, 2014, the study team recommended that the connection capacity needs at Wilson TS and Thornton TS will be best resolved through a wires alternative and that a "local" planning assessment should be undertaken between Hydro One and the affected LDCs. OPA confirmed and the study team agreed that other resource options such as CDM will not effectively defer the connection capacity needs or provide a long-term solution. As per the LDC's anticipated load growth in the region, the connection facilities are forecasted to exceed their normal supply capacity in the near-term and hence, the development and review of all viable options is required at the earliest to recommend a preferred solution(s). The local planning assessment was initiated in October 2014 and is currently in progress. In light of the updated total peak load forecast, the option of adding two new feeder breaker positions at both stations (Wilson TS and Thornton TS) is no longer deemed to be a viable permanent solution to address the station capacity limitations at both Wilson TS and Thornton TS.

At this time, the study team's assessment indicates that a new 230/44kV transformer station will be required to address the need for additional transmission station capacity. Currently, the in-service date of the proposed new station is expected to be in 2018/2019. The study team will be reviewing options (transformer size, number of initial feeder breaker positions, etc.) and associated budgetary estimates to determine the preferred solution(s) and related contributions to Hydro One.

As the proposed new station has an anticipated in service date of 2018/2019, the local planning study team is also reviewing interim options for managing the forecasted load at Wilson TS and Thornton TS. This includes the review of available station capacity and feeder capacity utilization in the GTA East Region, in order to make efficient and cost effective use of available facility capacity. These interim solution(s) may require additional LDC investments, which at this time is unknown. The local planning is expected to be complete in Q1 2015.

Depending on the outcome of the local planning assessment, required investments and any capital contributions from the benefitting LDCs may vary, and will be evaluated at that time as per the

TSC. OPUCN's capital contribution to HONI cannot be confirmed at this time, but could be in the range of $10 to $12 Million for a new 230/44kV DESN.

In addition to local planning, other potential needs in the GTA East Region identified in the August 11, 2014 Needs Screening report (Appendix C) are being assessed as part of the Scoping Assessment led by the OPA. These needs include:

- Station capacity at Cherrywood TS T7/T8 (230/44 kV),
- Station capacity at Whitby TS T1/T2 (230/27.6 kV),
- Load restoration for the loss of two elements (230 kV circuits), and
- Review available station capacity and feeder capacity utilization

Hydro One appreciates OPUCN's active participation in the Regional Planning process and looks forward to developing an effective and economical regional plan to address the needs in the GTA East Region. If you have any further questions, please feel free to contact me.

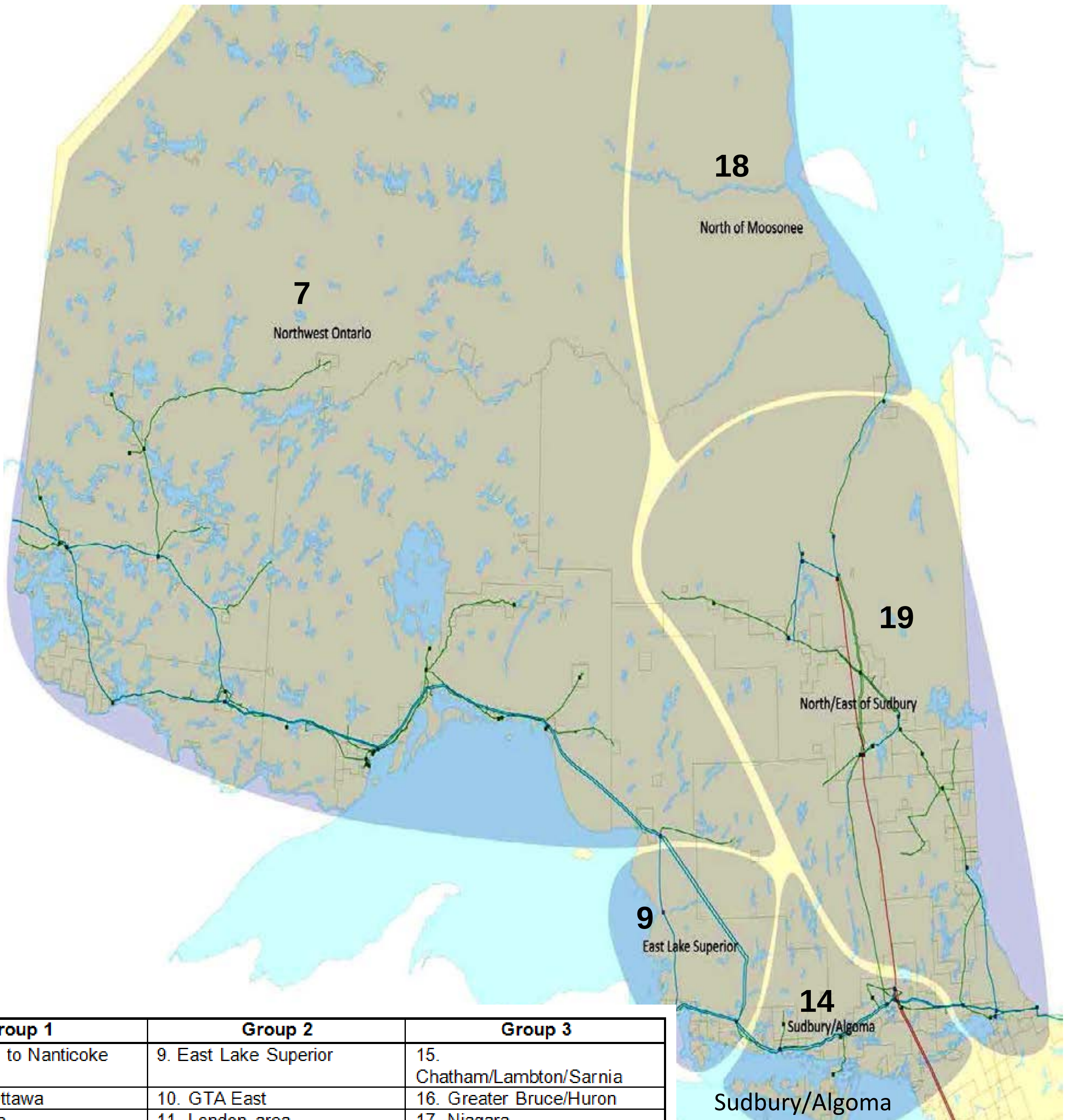
Sincerely,

Ajay Garg, |Manager - Regional Planning Coordination and Transmission Load Connections
Hydro One Networks Inc.

Cc:
Bing Young, Director – Transmission System Development
Farooq Qureshy, Manager – Transmission Planning (Central and East)
Brad Colden, Manager – Customer Business Relations

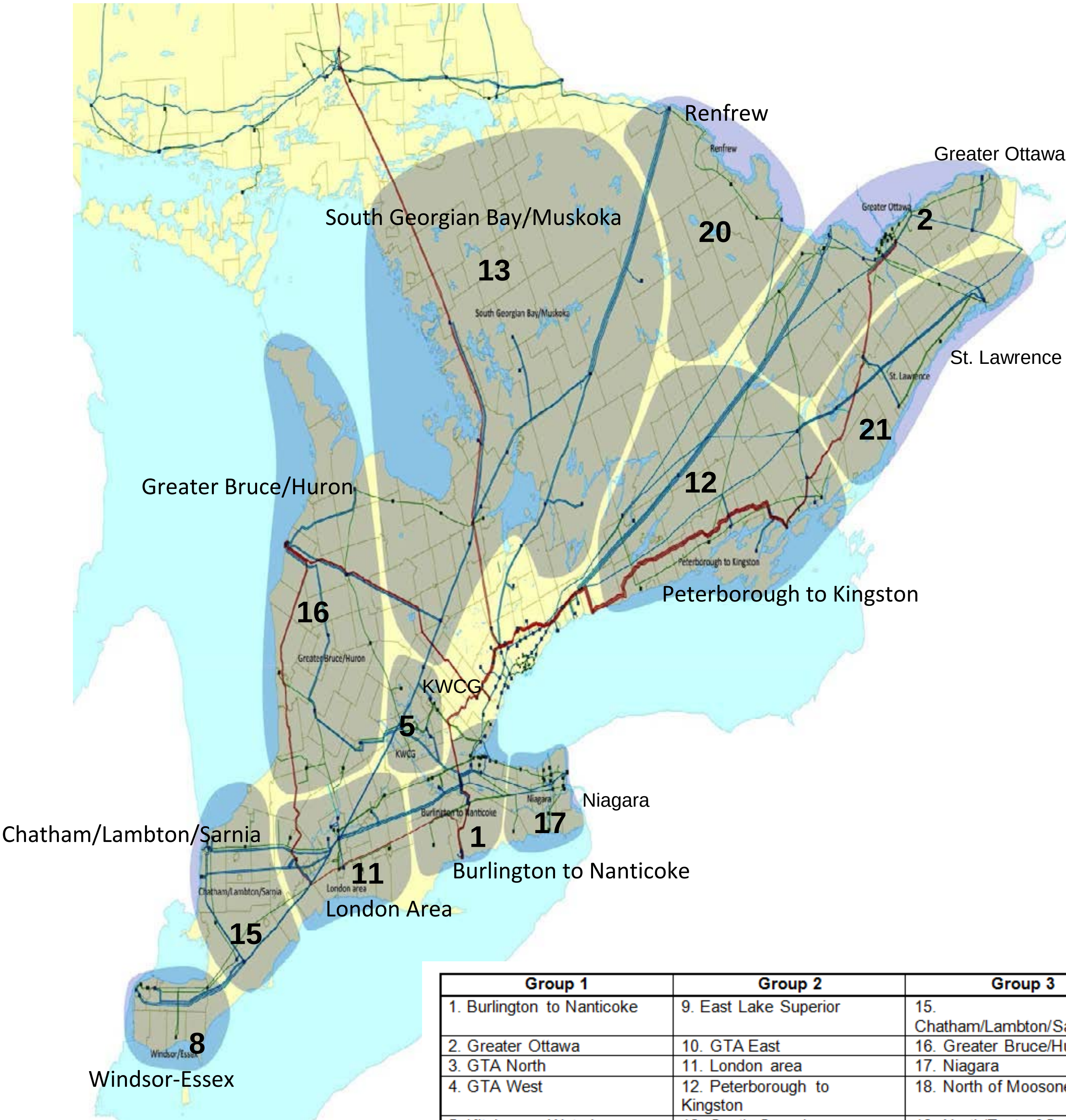
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
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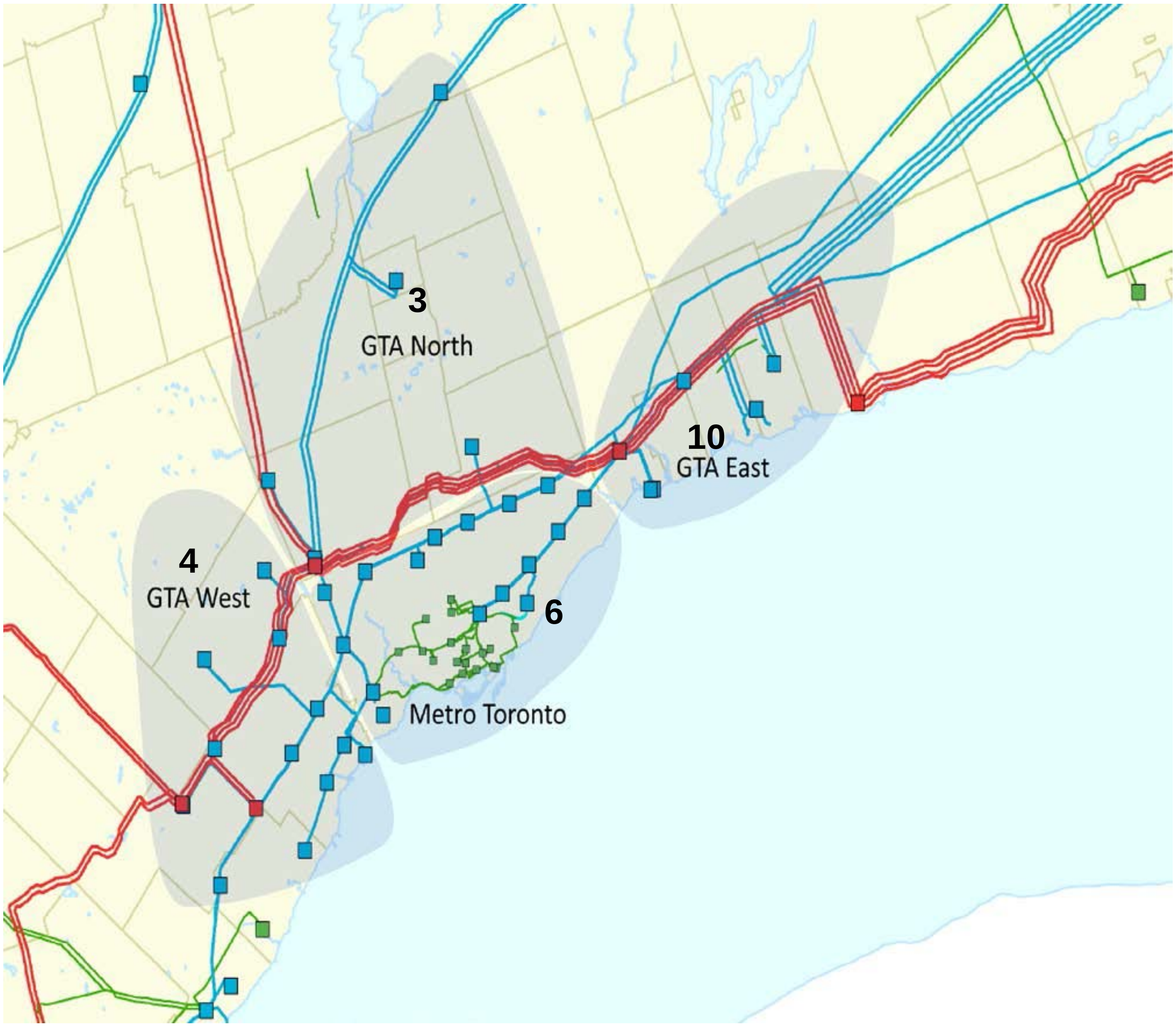
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
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4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc*. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. *Changes to the May 17, 2013 OEB Planning Process Working Group Report.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
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NEEDS SCREENING REPORT

Region: GTA East

Revision: Final
Date: August 11, 2014

Prepared by: GTA East Region Study Team

GTA East Region Study Team	
Organization	**Name**
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Ontario Power Authority	Steven Norrie
Independent Electricity System Operator	Phillip Woo
Veridian Connections Inc.	Craig Smith
Oshawa PUC Networks Inc.	Denise Flores
Whitby Hydro Electric Corporation	Kevin Whitehead
Hydro One Networks Inc. (Distribution)	Charlie Lee

Disclaimer

This Needs Screening Report was prepared for the purpose of identifying potential needs in the GTA East Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Screening Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Screening Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Screening Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Screening Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Screening Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Screening Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS SCREEN EXECUTIVE SUMMARY

REGION	GTA East Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 12, 2014	**END DATE**	August 11, 2014

1. INTRODUCTION

The purpose of this Needs Screening report is to undertake an assessment of the GTA East Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping Assessment process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Screening for the GTA East Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The GTA East Region was expedited at the request of the LDCs in the region and reprioritized from Group 2 to Group 1. The Needs Screening for this Region was triggered on June 12, 2014 and was completed on August 11, 2014.

3. SCOPE OF NEEDS SCREENING

The scope of this Needs Screening assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023, as per the recommendations of the Planning Process Working Group Report to the Board.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year IRRP with strategic direction for the Region.

The assessment included a review of transmission system connection facilities capability, which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the OPA, the Independent Electricity System Operator (IESO), and Hydro One transmission provided information for the GTA East Region. The information included: existing information from planning activities already underway, historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life. See Section 4 for further details.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230kV Transmission Lines

- The 230kV circuits supplying the Region (B23C, M29C, H24C, and H26C) are adequate over the study period for the loss of a single 230kV circuit in the Region. No action is required at this time and the capacity will be reviewed in the next planning cycle.

B. 230kV Connection Facilities

- The following stations exceed their normal supply capacity in the near term for both Gross and Net demand forecasts. See Section 6 for further details:
    - Cherrywood TS T7/T8 (230/44kV)
        - Based on the net demand forecast, the station exceeds its normal supply capacity for 2014 and 2015 only. However, as enough CDM is implemented, net demand is reduced and does not exceed normal supply capacity from 2016 to the end of the study period.
    - Whitby TS T1/T2 27.6kV windings (230/44/27.6kV)
    - Wilson TS T1/T2 and T3/T4 (230/44kV)
    - Thornton TS T3/T4 (230/44kV)
        - Capacity of the Thornton T3/T4 transformers is currently limited to their Continuous Rating since they have been identified as gassing. Hydro One is scheduled to replace both of these transformers in 2015 with two new 75/100/125 MVA transformers.
- There is a need to review available station capacity and feeder capacity utilization in the GTA East Region in the next regional planning step in order to make efficient and cost effective use of available facility capacity.

System Reliability, Operation and Restoration Needs

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this Region.

Based on the gross coincident demand forecast, the loss of one element will not result in load interruption. The maximum load interrupted by configuration due to the loss of two elements is below the 600MW load loss limit by the end of the 10-year study period.

For the loss of two elements, the load interrupted by configuration may exceed 150 MW and 250 MW. Load restoration times require further assessment.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace major equipment do not affect the needs identified. Scheduled replacement of the T3/T4 transformers at Thornton TS will eliminate the existing transformer gassing issue.

7. RECOMMENDATIONS

Based on the findings of this Needs Screening assessment, the study team's recommendations are as follows:

- Some of the potential needs identified in Section 6 do not require further regional coordination. Rather, these needs can be adequately and efficiently addressed by Hydro One Networks Inc. and the relevant LDCs. See Section 7 for further details.
- Coordinated regional planning is further required to assess some of the potential needs identified in Section 6 of this report. Accordingly, the OPA should initiate the Scoping Assessment process for these needs. See Section 7 for further details.

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LIST OF FIGURES AND TABLES

1 INTRODUCTION

This Needs Screening report provides a summary of needs that are emerging in the GTA East Region ("Region") over the next ten years. The development of the Needs Screening report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Prior to this Needs Screening coordinated planning activities, which included participation from the Ontario Power Authority (OPA), Local Distribution Companies (LDC) and Hydro One Networks Inc., were already underway to address some of the GTA East Region's station capacity needs. . The purpose of this Needs Screening report is to: consider the information from planning activities already underway; undertake an assessment of the GTA East Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the OPA will initiate the Scoping Assessment process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by the GTA East Region Needs Screening study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, the OPA and the Independent Electricity System Operator (IESO).

Table 1: Study Team Participants for GTA East Region

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter)
2.	Ontario Power Authority
3.	Independent Electricity System Operator
4.	Veridian Connections Inc. ("Veridian")
5.	Oshawa Power and Utilities Corporation Networks Inc. ("OPUCN")
6.	Whitby Hydro Electric Corporation ("Whitby Hydro")
7.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The Needs Screening for the GTA East Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. As mentioned earlier, planning activities were already underway in the GTA East Region to address some specific station capacity needs, and accordingly this Region was expedited at the request of LDCs and reprioritized from Group 2 to Group 1. The Needs Screening for this Region was triggered on June 12, 2014 and was completed on August 11, 2014.

3 SCOPE OF NEEDS SCREENING

This Needs Screening covers the GTA East Region over an assessment period of 2014 to 2023. The scope of the Needs Screening includes a review of transmission system connection facility capability which covers transformer station capacity, thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Screening.

3.1 GTA East Region Description and Connection Configuration

The GTA East Region comprises the municipalities of Pickering, Ajax, Whitby, Oshawa and parts of Clarington, and other parts of the Durham area. The boundaries of the GTA East Region are shown below in Figure 1.

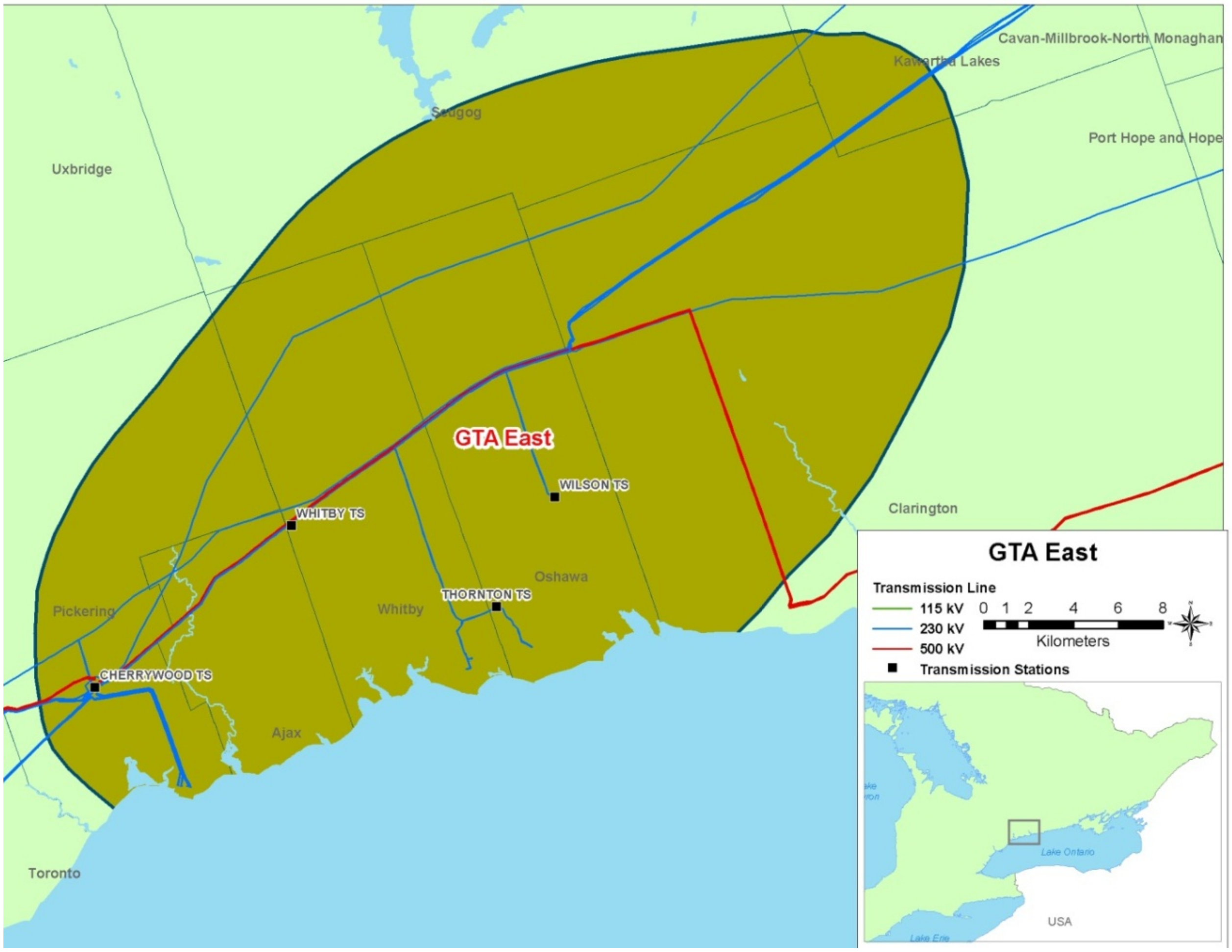


Figure 1: GTA East Region Map

Electrical supply to the GTA East Region is provided through 500/230kV autotransformers at Cherrywood Transformer Station (TS) and five 230 kV transmission lines connecting Cherrywood to Eastern Ontario. There are four Hydro One step-down transformer stations and three other direct transmission connected load customers. The distribution system is at two voltage levels, 44kV and 27.6kV.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Screening:

- Cherrywood TS is the major transmission station that connects the 500kV network to the 230kV system via four 500/230kV autotransformers.

- Four step-down transformer stations supply the GTA East load: Cherrywood TS, Whitby TS, Wilson TS, and Thornton TS.

- Three customer transformer stations (CTS) are supplied in the region: Atlantic Packaging CTS, Gerdau Ameristeel Whitby ("Gerdau") CTS, and Oshawa General Motors ("Oshawa G.M.") CTS.

- Four 230kV circuits (B23C, M29C, H24C, and H26C) emanating east from Cherrywood TS provide local supply to the GTA East Region. They extend from Cherrywood in the City of Pickering to Eastern Ontario. The 230kV circuit, C28C, and stations supplied by this circuit are not part of the GTA East Region.

- The Pickering Nuclear Generating Station (NGS) consists of 6 generating units with a combined output of approximately 3000 MW. It is connected to the 230kV system at Cherrywood.

- Whitby Customer Generating Station (CGS) is a 60 MW gas-fired cogeneration facility that connects to circuit H26C.

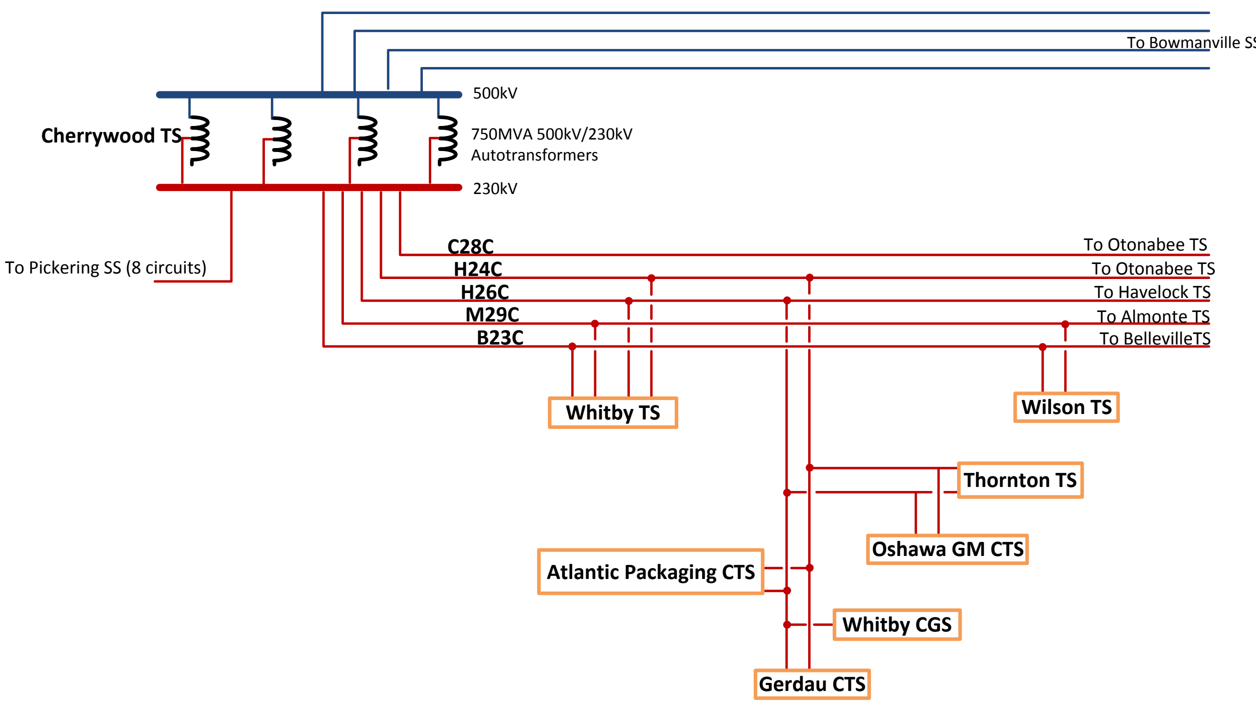


Figure 2: Single Line Diagram – GTA East Region

3.1.1 Clarington TS 500/230kV Autotransformer Station

A new 500/230kV autotransformer station in the GTA East Region within the township of Clarington (called Clarington TS) is being developed and is expected to be in-service in 2017. The new Clarington TS will provide additional load meeting capability in the Region and will eliminate the overloading of Cherrywood autotransformers that may result after the retirement of the Pickering Nuclear Generating Station (NGS).

The new autotransformer station will consist of two 750MVA, 500/230kV autotransformers and a 230kV switchyard. The autotransformers will be supplied from two 500kV circuits that pass next to the proposed site. The 230kV circuits supplying the east GTA will be terminated at Clarington TS. Clarington TS will become the principle supply source for the GTA East Region load. The modified GTA East Region with the connection to Clarington TS is shown in Figure 3.

This Needs Screening assessment is based on Clarington TS in-service and no Pickering generation units in-service.

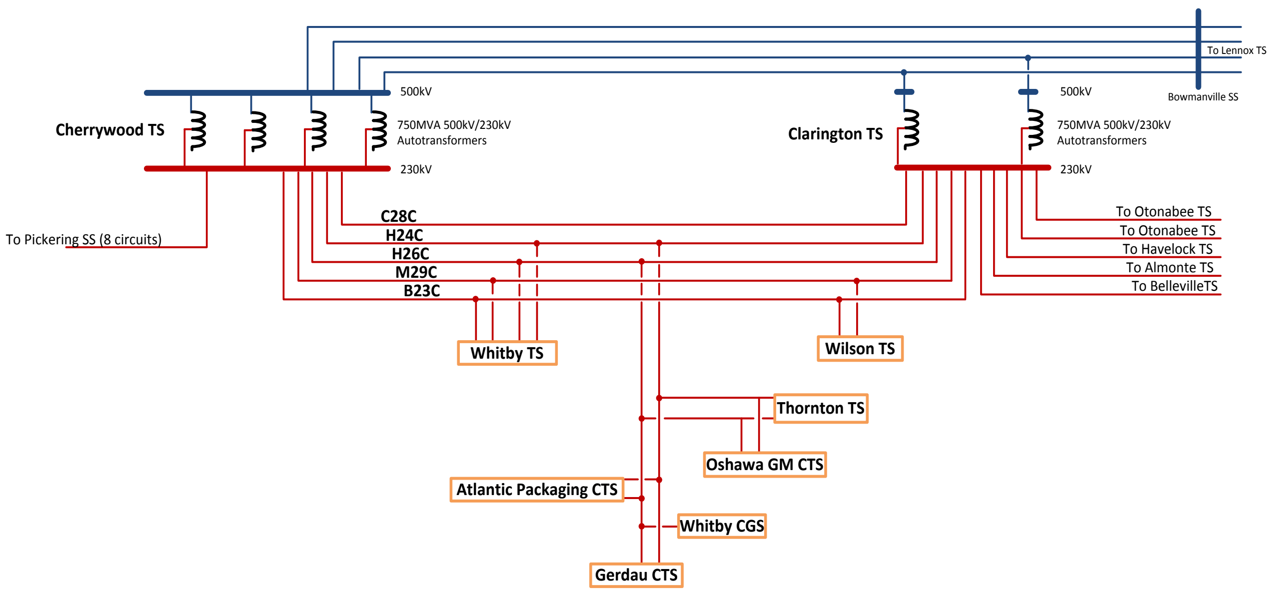


Figure 3: Single Line Diagram – GTA East Region with Clarington TS

4 INPUTS AND DATA

In order to conduct this Needs Screening, study team participants provided the following information and data to Hydro One:

- IESO provided:
    i. Historical 2013 regional coincident peak load and station non-coincident peak load
    ii. List of existing reliability and operational issues
- LDCs provided historical (2011-2013) net load and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- OPA provided Conservation and Demand Management (CDM) and Distributed Generation (DG) data

- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Load Forecast

As per the data provided by the study team, the load in the GTA East Region is expected to grow at an average rate of approximately 2.8% annually from 2014-2018 and 2.4% annually from 2019-2023.

5 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Screening assessment:

1. The Region is summer peaking so this assessment is based on summer peak loads.

2. Forecast loads are provided by the Region's LDCs

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer peak load as a reference point.

4. The 2013 summer peak loads are adjusted for extreme weather conditions according to Hydro One's methodology.

5. The gross demand forecast is used to develop a worst case scenario to identify needs. Both the gross demand forecast and the net demand forecast (which includes forecasted CDM and DG contributions) were used to determine the timing of the needs.

6. Review impact of any on-going and/or planned development projects in the Region during the study period. This includes:

   - New 500/230kV autotransformer station in the township of Clarington called Clarington TS, which is expected to be in-service in 2017. This Needs Screening assessment is based on Clarington TS in-service and no Pickering generation units in-service.

7. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.

8. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks. A more conservative power factor is assumed for stations having LV capacitor banks where necessary. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR).

9. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

10. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer 10-Day LTR.
    - All voltages must be within pre and post contingency ranges as per ORTAC criteria.
    - With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
    - With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC criteria.

6 RESULTS

This section summarizes the results of the Needs Screening in the GTA East Region. The results are based on Clarington TS in-service and no Pickering generation units in-service.

6.1 Transmission Capacity Needs

6.1.1 230kV Transmission Lines

The 230kV circuits supplying the Region (B23C, M29C, H24C, and H26C) are adequate over the study period for the loss of a single 230kV circuit in the Region.

6.1.2 230kV Connection Facilities

A station capacity assessment was performed over the study period for the 230kV transformer stations in the Region using the station summer peak load forecast provided by the study team. The results are as follows:

Cherrywood TS T7/T8 (230/44kV)

- From 2014 to the end of the study period, Cherrywood TS is forecast to slightly exceed its normal supply capacity based on the gross demand forecast (approximately 102% of Summer 10-Day LTR from 2014 to 2023). However, based on the planned CDM targets, the station capacity is adequate to meet the net demand over the study period, except for years 2014 and 2015. Further assessment is required for the 2014 and 2015 period when the forecasted load is approximately 101% of the Summer 10-Day LTR.

Whitby TS T1/T2 (230/44/27.6kV)

- In 2019, Whitby TS T1/T2 27.6kV is forecast to reach its normal supply capacity based on the gross demand forecast (100% of Summer 10-Day LTR from 2019 to 2023). However, based on the net demand forecast it does not exceed its normal supply capacity during the study period.

  A new community in North Pickering within Veridian Connections Inc.'s service territory is being developed and the LDC plans to supply the additional load at 27.6kV. Veridian has forecasted the gross demand to be approximately 5MW in 2018 up to 75MW in 2023 (includes load growth at Whitby TS T1/T2 27.6kV and Cherrywood TS T7/T8 for incremental load). Hence, future 27.6kV supply is required. Prior to this Needs Screening, Hydro One was working with Veridian to assess the station capacity requirements and discussed plans for a proposed new 230/27.6kV station called Seaton TS. Further assessment is required.

- Whitby T1/T2 44kV does not exceed its normal supply capacity during the study period. Therefore, no action is required at this time and the capacity need will be reviewed in the next planning cycle.

Whitby TS T3/T4 (230/44kV)

- Based on the gross demand forecast, Whitby TS T3/T4 does not exceed its normal supply capacity during the study period. However, it is forecasted to be greater than 90% of the Summer 10-Day LTR from 2014 to the end of the study period. No action is required at this time and the capacity need will be reviewed in the next planning cycle.

Wilson TS T1/T2 DESN1 (230/44kV)

- In 2014 and 2017 to the end of the study period, Wilson TS DESN1 is forecast to exceed its normal supply capacity based on the gross demand forecast (approximately 100.4% and 126% of Summer 10-Day LTR in 2014 and 2023 respectively). From 2015-2016, the load is forecast to fall below the Summer 10-Day LTR as a result of a planned load transfer by OPUCN from Wilson TS DESN1 to Thornton TS that may be required. Based on the net demand forecast, Wilson TS DESN1 is forecast to exceed its normal supply capacity from 2018 to the end of the study period (approximately 101% and 117% of Summer 10-Day LTR in 2018 and 2023 respectively). Transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs.

It should also be noted that Hydro One Distribution's customer that is supplied by this DESN is currently a 10MW participant of OPA's Demand Reduction (DR) Program, where they reduce their load during peak hours under IESO's direction. For this assessment, this customer's load is assumed constant for the entire study period at a reduced level due to its participation in the DR program. However, if the customer ends its participation in the DR program earlier, then Wilson TS DESN1 may reach its normal supply capacity earlier.

Wilson TS T3/T4 DESN2 (230/44kV)

- Wilson T3/T4 DESN2 is forecasted to exceed its normal supply capacity from 2014-2023 for both the gross and net demand forecasts (approximately 124% and 115% of Summer 10-Day LTR for gross and net forecasts respectively in 2014 and 140% and 107% for gross and net forecasts respectively in 2023).

  Prior to 2010, Hydro One and impacted LDCs were in discussions and developing plans for a proposed new 230/44kV station called Enfield TS that would provide transformation capacity relief to Wilson TS. These plans did not proceed further as the anticipated load did not materialize to support the construction at that time. As per the current load forecast provided by the study team, transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs. In the past, overloading at Wilson TS DESN2 under certain conditions was significant enough that emergency rotating load shedding was required.

Thornton TS (230/44kV)

- From 2015 to the end of the study period, Thornton TS is forecast to exceed its normal supply capacity based on the gross and net demand forecast (approximately 114% and 110% of Summer 10-Day LTR for gross and net forecasts respectively in 2018 and 118% and 109% for gross and net forecasts respectively in 2023).

  It should be noted that the load forecast for Thornton TS is higher than historical levels due to significant load growth at the station, particularly as a result of anticipated Metrolinx load. In addition, to help manage the affected LDC's load growth and respect 10-Day LTRs of other stations, over 60MW of load transfers to Thornton TS were included in the station's load forecast (load transfers from Wilson TS DESN1 in 2013 and 2015 and Whitby TS T3/T4 in 2013) and the associated distribution investments required by the LDC were made. Transformation capacity relief is needed and further assessment is required between the transmitter and impacted LDCs.

Currently, capacity of the Thornton T3/T4 transformers has been limited to their Continuous Rating since they have been identified as gassing. Hydro One is scheduled to replace both of these transformers in 2015 with two new 75/100/125 MVA transformers.

Available station capacity and feeder capacity utilization in the GTA East Region also needs to be reviewed in the next regional planning step in order to make efficient and cost effective use of available facility capacity.

6.2 System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for this Region.

Based on the gross coincident demand forecast, the loss of one element will not result in load interruption. The maximum load interrupted by configuration due to the loss of two elements is below the load loss limit of 600MW by the end of the 10-year study period.

For the loss of two elements, the load interrupted by configuration may exceed 150 MW and 250 MW. Load restoration requires further assessment.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment initiatives that are currently planned for the replacement of any auto-transformers, power transformers and high-voltage cables.

During the study period:

- Replacement of both transformers (T3 and T4) at Thornton TS is scheduled in 2015. This will eliminate the existing transformer gassing issue, but will not address capacity needs at the station.
- There are no significant lines sustainment plans scheduled in the near term for circuits in this region.

7 RECOMMENDATIONS

Based on the findings of the Needs Screening assessment, the study team's recommendations are as follows:

a) The following needs identified in Section 6 do not require further regional coordination. Rather, these potential needs can be adequately and efficiently addressed by Hydro One Networks Inc. and the relevant LDCs.
   - Wilson TS T1/T2 DESN1 (230/44kV) – station capacity need
   - Wilson TS T3/T4 DESN2 (230/44kV) – station capacity need
   - Thornton TS T3/T4 (230/44kV) – station capacity need

b) Coordinated regional planning is further required to assess the following needs identified in Section 6. The OPA will undertake a Scoping Assessment to determine the appropriate process to address these needs:
   - Cherrywood TS T7/T8 (230/44kV) – station capacity need
   - Whitby TS T1/T2 27.6kV supply (230/44/27.6kV) – station capacity need
   - Load restoration for the loss of two elements

   As part of the Scoping Assessment process, it will be determined whether the OPA-led IRRP process and/or the transmitter-led RIP process (for wires solutions) should be further undertaken.

Available station capacity and feeder capacity utilization in the GTA East Region is also recommended for review as part of further assessing the needs identified in 7a) and 7b) in order to make efficient and cost effective use of available facility capacity.

c) The following potential needs in Section 6 will be monitored and assessed in the next Regional Planning cycle for the GTA East Region:
   - Normal supply capacity at Whitby TS T1/T2 44kV windings and Whitby TS T3/T4
   - Monitor and assess load growth on 230kV transmission circuits B23C/M29C and H24C/H26C for loss of two elements (600MW limit).

8 NEXT STEPS

Following the Needs Screening process the next regional planning steps, based on the results of this report, are:

- Hydro One Transmission and impacted LDCs to develop and implement local solutions for the needs identified in Section 7a) ; and
- OPA to initiate a Scoping Assessment to determine which of the needs in Section 7b) require an IRRP and/or RIP

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0
iv) IESO System Impact Assessment Report for Clarington TS (CAA ID#: 2012-462)

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NS	Needs Screening
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

OSHAWA PUC Networks Inc.
A Lifetime of Power.

ASSET CONDITION ASSESSMENT REPORT
&
ASSET MANAGEMENT PLAN

Prepared by:

METSCO
Energy Solutions

February, 2014

ASSET CONDITION ASSESSMENT REPORT
&
ASSET MANAGEMENT PLAN

Prepared by: Shawn Otal, MBA, P.Eng.

Peer Review by: Thor Hjartarson, M.A.Sc., P.Eng.

February, 2014

EXECUTIVE SUMMARY

This report prepared by METSCO Energy Solutions Inc. (METSCO), documents results of the health and condition assessment completed in December 2013 covering all fixed assets employed on the power distribution system owned and operated by Oshawa PUC Networks Inc. (OPUCN). The report provides a complete picture of the existing health and condition of the distribution system assets at the end of 2013 and provides quantitative estimates of the assets found in poor and very poor condition, requiring rehabilitation or replacement over the next five year period. The condition assessment of revenue meters is not included in this report, because a vast majority of the assets in this class are virtually brand new, replaced in the recent past under the province's smart metering initiative. Auxiliary assets, such as motor vehicles, tools and equipment and IT systems etc. are not covered in this report.

The methodology utilized in this study is an integral part of a risk based asset management strategy that is based on the Asset Management Standard PAS-55, a specification developed by British Standards Institute (BSI) and commonly employed by progressive electric utilities. This asset management strategy determines the timing and scope of investments into asset renewal, based on the risk of an asset's failure determined by the condition of the asset and consequences of its failure in service.

The first step towards implementation of a risk based asset management approach is to develop a yard stick to measure and benchmark the health and condition of assets and to determine the risk of in-service failure of assets. A comprehensive methodology for development of health indices for various assets has been developed and documented in Section 3 of the report, to quantitatively measure the health of all fixed assets employed on Oshawa PUCN's distribution network, including the assets employed in substations, overhead lines and underground distribution system.

By applying this methodology, condition assessment of the assets has been completed and is documented in Section 4, providing the health indices and quantitative estimates of assets in different health index categories. In determining the health indices of assets, all available information relevant to the assets' health, described in Section 3 of this report, has been utilized. Where information on a health parameter was not available, health index has been calculated using a modified algorithm, utilizing only those parameters on which information was available. Section 5 contains an asset management plan, providing estimates of investments required to replace the assets at the end of or their useful service life.

The overall capital investments requirements for sustainment of fixed assets are summarized below:

	2015		2016		2017		2018		2019	
	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab
Substations	$ 175,000	$ 7,500	$ 175,000	$ 7,500	$ 440,000	$ 60,000	$ 440,000	$ 60,000	$1,230,000	$ 145,000
Underground Cables	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260
Overhead Lines	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600
Disconnect Switches and Cutouts	$ 156,667	$ 224,000	$ 156,667	$ 224,000						
Pad mounted Dist Transformers	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800
Pole mounte Dist Transformers	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250
Vault Mounted Dist Transformers	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500
Submersible Dist Transformers	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417
Downtown Core Underground Duct/Manhole/Vault system	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 175,000	$ 175,000	$ 100,000	$ 100,000
Total Capital Investments Into Sustainement	$ 2,114,915	$ 2,189,327	$ 2,114,915	$ 2,189,327	$ 2,223,249	$ 2,017,827	$2,323,249	$ 2,117,827	$3,038,249	$ 2,127,827
Total Capital Investments Into Sustainement	$ 4,304,242		$ 4,304,242		$ 4,241,075		$ 4,441,075		$ 5,166,075	

Contents

1 Introduction

This report summarizes the results of an Asset Condition Assessment study performed by METSCO in December 2013 on behalf of OPUCN with the objective establishing the health and condition of fixed assets currently in service on OPUCN's distribution system and identifying the assets in poor condition that present high risk of failure in service.

The assets covered by the report include fixed assets employed on:

- Distribution substations
- Overhead distribution lines;
- Underground distribution lines;
- Distribution transformers; and
- Switches and Cut-outs installed in pole-mounted and pad-mounted configurations.

The report is organized into five (5) sections including this introductory section:

Section 2 describes the general principles of the risk based asset management strategy to achieve optimal operation of the distribution grid. Section 3 describes the methodology for ranking and benchmarking the health of assets, through health index development. Section 4 documents the results of asset condition assessment exercise. Section 5 documents the asset management plan, summarizing the capital investments required to replace the assets at the end of their useful service life.

2 Strategic Management of Distribution Fixed Assets

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based Asset Management Strategy, therefore, determines the risk of asset failure based on the condition of the asset, which is commonly measured with the help of a yard stick of “Asset Health Indices”, and computes the valuation of the risk based on consequences of asset failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset’s service life – and finally to the determination of the assets end-of-life and retirement from service. At each stage of an asset’s life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by the British Standards Institute (BSI) and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with the PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Exhibit 2-1.

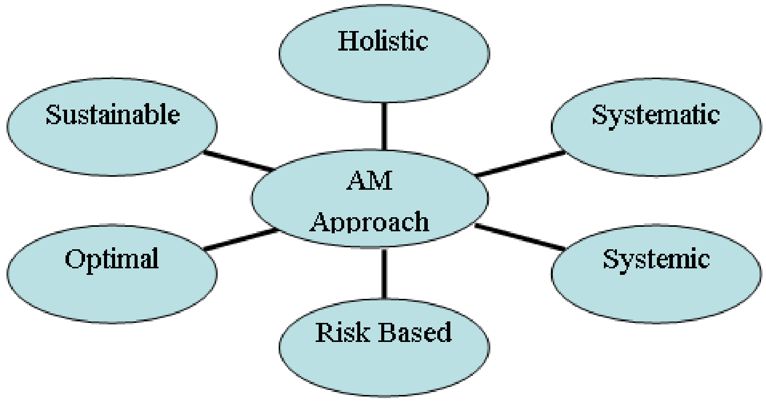


Exhibit 2-1: Essentials of PAS-55 Compliant Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of ten to twenty-five years to achieve optimal system performance by placing appropriate weights on corporate objectives and performance requirements, as shown in Exhibit 2-2.

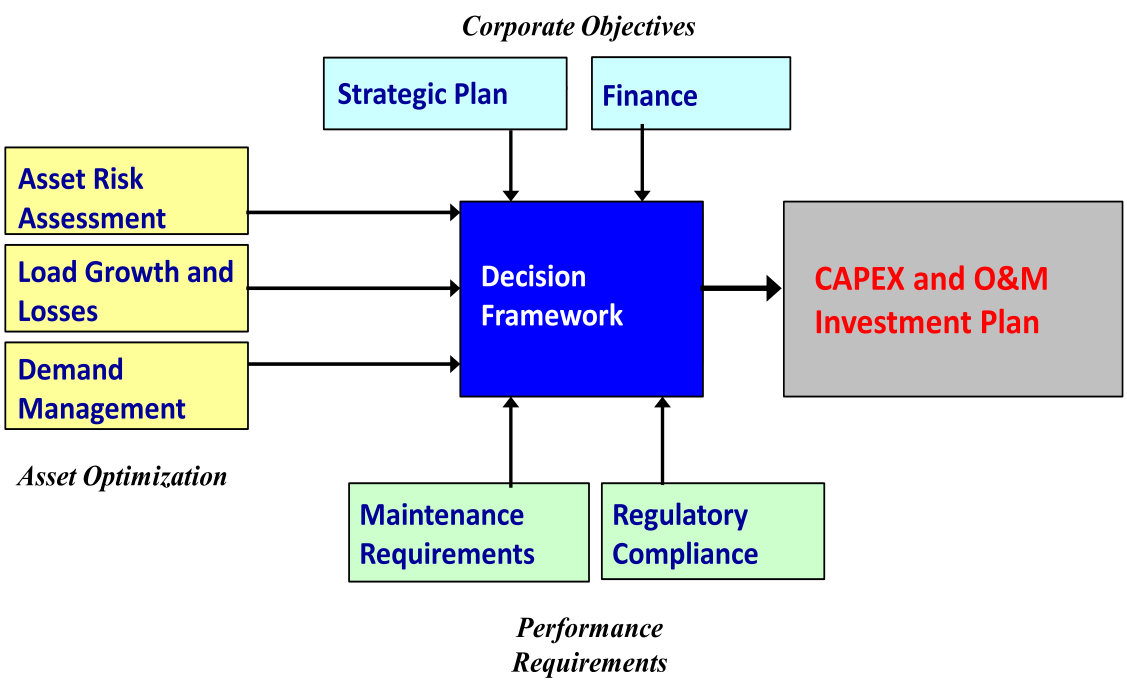


Exhibit 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

- Regulatory Compliance
- Public and Employee Safety
- Protecting Brand Name and Image
- Operating Efficiency
- Reliability and Supply System Security
- Customer Service Quality
- Getting Full Life out of Assets
- Return on Investment
- Risk Based Maintenance Strategy
- Minimizing Asset Life Cycle Costs
- Minimizing Risk of Premature Failures
- Minimizing Environmental Risks

Exhibit 2-3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

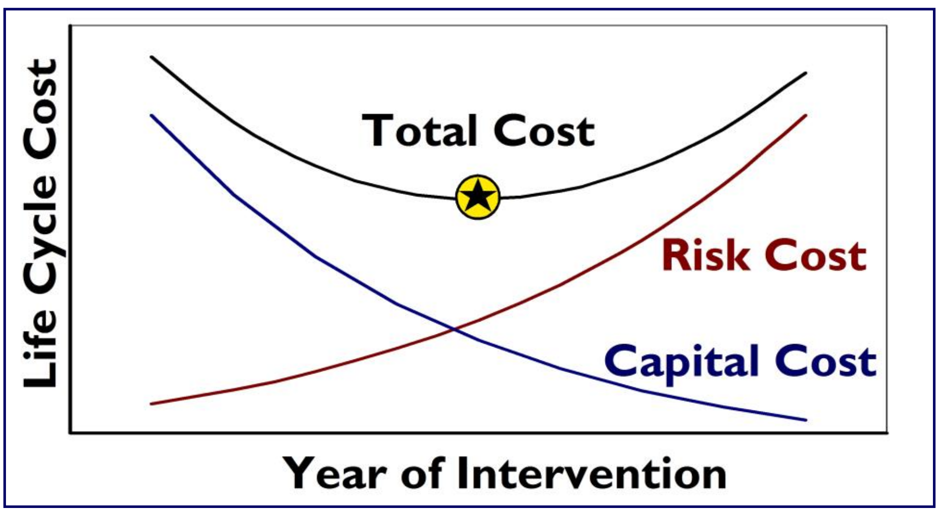


Exhibit 2-3: Risk Based Decision Support System

Exhibit 2-4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are commonly used to express the health and condition of assets, as shown in Exhibit 2-5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan that could be implemented over a 5-10 year period.

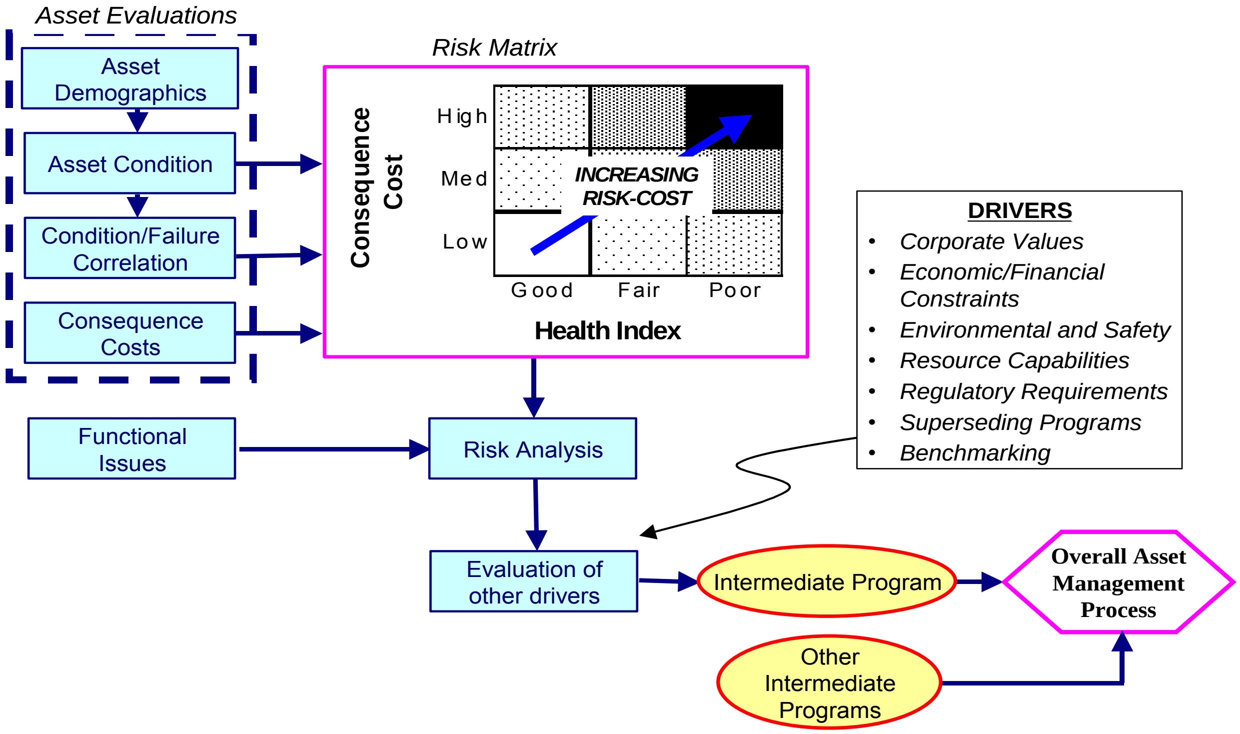
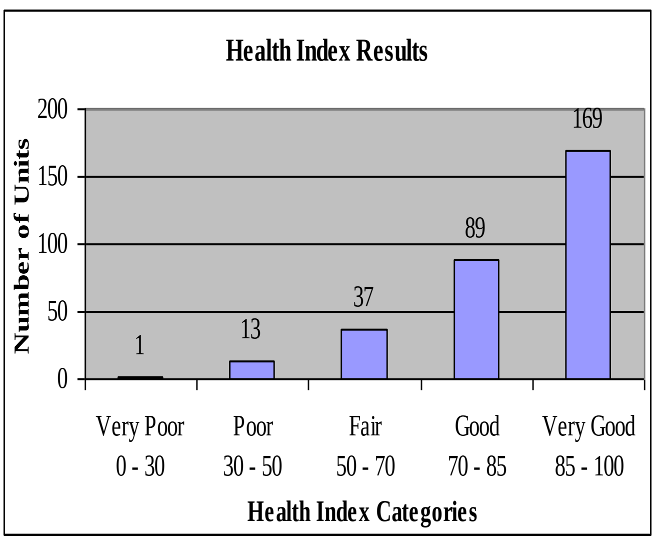


Exhibit 2-4: Model to Identify Assets with Highest Risks



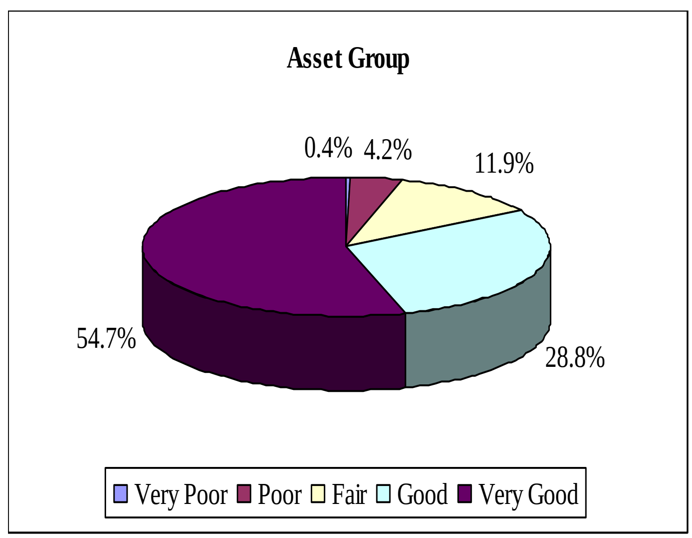


Exhibit 2-5: Graphs to Identify Assets with Highest Risks

3 ASSET CONDITION ASSESSMENT METHODOLOGY

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on Oshawa PUCN's distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Asset Condition Assessment methodologies are described below for the following distribution system asset categories:

- Overhead Lines
- Underground Lines
- Substations
- Distribution Transformers (pole mounted, pad mounted, pole trans and vault mounted)
- Distribution Switches and Fused Cut-outs
- Low Voltage system

The components and tests shown in the tables are weighted based on their importance in determining the assets end-of-life.

For purposes of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

A= 5
B = 4
C = 3
D = 2
E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset.

Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each asset. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

3.1. Substations

The major assets employed in substations include:

- Station Transformers
- Circuit Breakers or Reclosers
- Controls and Protective Relays

- Control Battery and Chargers
- Ground Grid
- Perimeter Fences
- Buildings

3.1.1. Condition Assessment of Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. In case of Oshawa PUCN, station transformers step down from 44 kV sub-transmission voltages to 13.2 kV.

The key components of pad-mounted power transformers employed at municipal stations are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of cellulose paper and mineral oil
- transformer tank, either sealed or breather type, and
- primary and secondary bushings.
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and cellulose paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, therefore, provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to insulation failure if the transformer is subjected to mechanical shocks that are common in normal operating conditions. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis provides information on three critical factors:

- condition of the oil from moisture, acidity and breakdown strength measurements,
- condition of the paper insulation from Furan, carbon dioxide, carbon monoxide and moisture measurements, and,

- presence of any incipient electrical or thermal faults within the transformer from the DGA results.

Some other tests that can be applied to oil samples such as interfacial tension, power factor etc.

3.1.2. Ranking Condition of Station Transformers through Multiple Criteria

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Condition Rating	Station Transformer Age
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 50 years
E	Older than 50 years

Exhibit 3-1: Station Transformers – Age Related Health Score

(b) Condition Assessment Based on Loading Level

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Circuit loading of 100% to 125% of its rating
E	Circuit loading of greater than 125% of its rating

Exhibit 3-2: Station Transformers – Load Related Health Score

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Condition Rating	Visual Inspections
A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

Exhibit 3-3: Station Transformers – Health Score Based on Visual Inspections

(d) Condition Rating Based on Testing of the Insulating Oil

Various insulation tests, including dissolved gas in oil analysis (DGA), dielectric strength or water content measurement test can be interpreted by an expert to rank the overall condition of transformer insulation system:

Condition Rating	Test Results
A	Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition
E	Two or more of the tests indicate rapidly deteriorating insulation condition

Exhibit 3-4: Station Transformers – Health Score Based on Oil Tests

3.1.3. Condition Assessment Criteria for Circuit Breakers or Reclosers

Medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. A pole mounted recloser virtually provides the same functions as a circuit breaker. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or vacuum circuit breakers. In order to deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- Highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- High quality contact mating, capable of retaining high conductivity over time;
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

OCBs typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

Different types of circuit breakers employed on OPUCN's distribution system are described below:

3.1.4. Oil Circuit Breakers (OCB) or Oil Filled Reclosers

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced. Generally, after 4 to 8 fully rated interruptions, OCB's require preventative maintenance, during which excessive contact erosion, carbonisation of oil, and maintenance of operating mechanism may need to be attended to. The manufacture of new OCBs has been discontinued for at least 25 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

3.1.5. Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

3.1.6. Vacuum Circuit Breakers or Reclosers

In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time interval measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

3.1.7. SF6 Circuit Breakers

A SF_6 circuit breaker is designed to direct a constant gas flow to the arc that extracts heat from the arc and so allows achieving its extinction at current zero. The gas flow de-ionises the contact gap and establishes the required dielectric strength to prevent an arc re-strike. The direction of the gas flow either parallel or across to the axis of the arc has an influence on the efficiency of the arc interruption process. Research has shown that an axial flow creates a turbulence causing an intensive and continuous interaction between the gas and plasma as current approaches zero. Recent developments concentrated on employing the arc energy itself to create directly the differential pressure needed, without using an external piston. Parallel to the self-pressurising design, the rotating arc SF_6 interrupter was also developed. In this design, a coil sets the arc in rotation while the quenching medium remains stationary. The relative movement between the arc and the gas is no longer axial but radial; it is a cross-flow mechanism.

3.1.8. Ranking Condition of Circuit Breakers and Reclosers through Multiple Criteria

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Condition Rating	Age of Outdoor Circuit Breaker / Recloser
A	0 to 7 years
B	8 to 15 years
C	16 to 24 years
D	25 to 32 years
E	33 years or older

Exhibit 3-5: Outdoor Circuit Breakers or Reclosers – Age Related Health Score

Condition Rating	Age of Indoor Circuit Breaker
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

Exhibit 3-6: Indoor Circuit Breakers – Age Related Health Score

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers or reclosers, which can be ranked as indicated below:

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

Exhibit 3-7: Circuit Breakers – Visual Inspections Based Health Score

(c) Condition Rating Based on Evaluation of the tests

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of breaker insulation system:

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

Exhibit 3-8: Circuit Breakers and Recloser – Testing Based Health Score

3.1.9. Condition Assessment Criteria for Protection Relays and RTUs

The function of protection relays on distribution systems is to detect and annunciate abnormal operating conditions and initiate circuit breaker or recloser trip to isolate faulty circuits from healthy circuits. Protection relays obtain their input from instrument transformers, process the information and automatically take corrective action with adequate speed and selectivity.

Electro-mechanical designs of protection relays have been in use in the industry for several decades, but the industry best practice has been to replace these relays with solid state and microprocessor relays. Electro-mechanical relays have many moving parts and require calibration at regularly scheduled intervals to assure accurate operation. Modern micro-processor relays have no moving parts and can provide much more accurate operation without requiring frequent calibration.

The electro-mechanical relays with many moving parts lose their operating accuracy due to the moving parts developing friction or the springs becoming weak with passage of time and need to be readjusted from time to time. Voltage and current surges can also harm electrical components of relays. The micro-processor and the solid state relays do not require frequent calibrations, but they are vulnerable to voltage and current surges.

3.1.10. Ranking of Protection Relays Condition through Multiple Criteria

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of protection relays. Since the relays are either installed indoors or in weatherproof cabinets, they are protected from the weather elements.

Condition Rating	Age of Protection Relay
A	0 to 5 years
B	6 to 10 years
C	11 to 15 years
D	16 to 20 years
E	Older than 20 years

Exhibit 3-9: Protection Relays – Age Based Health Score

(b) Condition Rating Based on Evaluation of the tests

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Condition Rating	Test Results
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

Exhibit 3-10: Protection Relays – Testing Based Health Score

3.1.11. Control Battery and Chargers

The purpose of substation control batteries is to provide power for critical control functions such as trip coils of circuit breakers. Two types of batteries are commonly used: lead acid batteries and nickel cadmium batteries. Batteries are carefully sized to store adequate energy for system operation during an AC power failure.

The key parts of a control battery include two electrodes immersed in an electrolyte inside a container. The battery terminals are brought out for cable connections. While the earlier vintages of control batteries required frequent maintenance and monitoring of electrolyte, modern batteries employ sealed design and are virtually maintenance free for the service life.

Battery chargers employ solid state rectifiers and are equipped with normal slow charge or fast charge functions.

Both the electrodes and electrolyte in control batteries undergo aging with repeated charge and discharge cycles, which result in gradual reduction of battery storage capacity. The end of life is reached when the battery is no longer able to retain adequate charge for required functions.

Battery chargers can experience component failures, but these can be easily replaced and as a result the charger often outlasts the battery.

3.1.12. Ranking Condition Control Batteries through Multiple Criteria

(a) Age Related Scoring

Since different types of batteries can have significantly different life expectancy, age related scoring needs to be measured in terms of manufacturer recommended life expectancy:

Condition Rating	Age of Battery
A	Less than 25% of manufacturer recommended age
B	Less than 50% of manufacturer recommended age
C	Less than 75% of manufacturer recommended age
D	Less than manufacturer recommended age
E	More than manufacturer recommended age

Exhibit 3-11: Control Batteries and Chargers – Age Related Health Score

(b) Condition Rating Based on Evaluation of the tests

Condition Rating	Test Results
A	Battery capable of storing full rated energy
C	Battery stores marginally less than full rated energy, but still adequate for required functions
E	Battery stores significantly less than the full rated energy, inadequate for required functions

Exhibit 3-12: Control Batteries and Chargers – Test Based Health Score

3.1.13. Substation Ground Grids

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

3.1.14. Ranking Condition of Ground Grids through Multiple Criteria

The health and condition of a ground grid can be verified though ground grid resistance measurements and integrity tests.

(a) Age Related Scoring

Condition Rating	Age of Ground Grid
A	Ground Electrode less than 10 years old
B	Ground Electrode Between 10 and 20 years Old
C	Ground Electrode Between 20 and 30 years Old
D	Ground Electrode Between 30 and 40 years Old
E	Ground Electrode More than 40 years Old

Exhibit 3-13: Ground Grid – Age Related Score

(b) Condition Rating Based on Evaluation of the tests

Condition Rating	Test Results
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

Exhibit 3-14: Ground Grid – Testing Related Health Score

(c) Rating Based on Condition of Surface Stone

Condition Rating	Test/Inspection Results
A	Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth

Exhibit 3-15: Ground Grid – Testing Related Health Score

3.1.15. Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life.

To achieve this objective the fence has to be of a minimum height of 1.8 m to comply with the Ontario Electrical Safety Code and topped with three rungs of barbed wire covering a height of 0.3 m. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 0.1 m or less. Where a substation fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations.

The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs.

3.1.16. Ranking Condition of Fences through Multiple Criteria

(a) Condition Rating Based on Evaluation of the tests

Condition Rating	Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

Exhibit 3-16: Fences Health Score based on Visual Inspections

3.1.17. Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

3.1.18. Ranking Condition of Substation Buildings through Multiple Criteria:

The health and condition of a substation building can be measured through visual inspections:

Condition Rating	Inspections
A	No deficiencies in the building
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

Exhibit 3-17: Substation Buildings Health Score

3.1.19. Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A - E	5	6	30
2	Peak loading	A - E	5	4	20
3	Visual inspection	A - E	5	2	10
4	Testing	A - E	5	8	40
	Total				100

Exhibit 3-18: Station Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Circuit Breaker	A - E	5	8	40
2	Visual inspection	A - E	5	4	20
3	Testing	A - E	5	8	40
	Total				100

Exhibit 3-19: Circuit Breakers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Protection Relay/RTU	A - E	5	10	50
2	Testing	A - E	5	10	50
	Total				100

Exhibit 3-20: Protection Relays and RTUs – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Battery/Charger	A - E	5	10	50
2	Testing	A - E	5	10	50
	Total				100

Exhibit 3-21: Substation Control Batteries and Chargers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Ground Grid	A - E	5	8	40
2	Testing	A - E	5	8	40
3	Visual Inspection	A - E	5	4	20
	Total				100

Exhibit 3-22: Substation Ground Grid – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Visual Inspection	A - E	5	20	100
	Total				100

Exhibit 3-23: Substation Fences – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Visual Inspection	A - E	5	20	100
	Total				100

Exhibit 3-24: Substation Buildings – Health Index

3.2. Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Poles
- Insulators
- Hardware
- Conductors and splices

3.2.1. Condition Assessment Criteria for Poles

As wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

3.2.2. Condition Assessment Criteria for Insulators

The types of insulators and configurations typically used in distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arcing damage/galvanizing;
- Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM or silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

3.2.3. Condition Assessment Criteria for Metal Cross Arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.2.4. Ranking Condition of Poles and Accessories through Multiple Criteria

The condition assessment process includes scoring based on multiple parameter criteria as described below:

a) Age Related Score

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Condition Rating	Age of Pole
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	51 years or older

Exhibit 3-25: Overhead Lines – Pole Age Related Health Score

b) Preservative Treatment Based Scoring for Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Condition Rating	Type of Pole Treatment
A	Fully Treated
C	Butt Treated
E	No Treatment

Exhibit 3-26: Overhead Lines – Pole Treatment Based Health Score

c) Condition Rating Based on Visual Examinations of Pole Line Components

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Condition Rating	Component Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component has damaged/degraded beyond repair and will require replacement

Exhibit 3-27: Overhead Lines - Visual Inspections Based Health Score

3.2.5. Condition Assessment Criteria for Conductors

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- Aluminium Stranded Conductors (ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

Because of the relatively short span lengths employed on distribution lines in relation to transmission lines, the tensile strength of conductors on distribution lines is not as critical as it is on transmission lines. Most distribution utilities these days, therefore, employ all aluminium conductors on distribution lines. Aluminium alloy conductors are sometimes used on distribution lines with longer span lengths.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation, corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

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

Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

3.2.6. Condition Assessment Criteria for Splices

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor's life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor's strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.2.7. Ranking Condition of Conductors and Splices through Multiple Criteria

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the following parameters:

Age Related Scoring

Since the service age provides a reasonably good measure of the remaining strength of conductors and all the defects are not easily detected through visual inspections, an age based criteria is proposed as indicted below:

Condition Rating	Age of Overhead Conductor
A	0 to 10 years
B	11 to 20 years
C	21 to 40 years
D	41 to 50 years
E	51 years or older

Exhibit 3-28: Conductors and Splices – Age Related Health Score

3.2.8. Small Conductor Risk

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Condition Rating	Small Sized Conductor
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

Exhibit 3-29: Overhead Lines - Small Conductor Related Health Score

3.2.9. Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various Health Index criteria described in Section 3.2.1 through 3.2.7.

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of pole line	A - E	5	3	15
2	Visual inspection of poles	A - E	5	1	5
3	Pole testing	A - E	5	4	20
4	Visual inspection of insulators	A - E	5	1	5
5	Visual inspection of hardware	A - E	5	1	5
6	Age of conductors	A - E	5	1	5
7	Small conductor risk	A - E	5	5	25
	Total				80

Exhibit 3-30: Overhead Lines – Health Index Calculation

3.3. Underground Distribution System

The major assets employed on underground distribution systems can be grouped into the following categories:

Cables, splices and terminations
Manholes and vaults

3.3.1. Condition Assessment Criteria for Cables, Splices and Terminations

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

3.3.2. Condition Assessment Criteria for Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

3.3.3. Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Condition Rating	Age of Underground Cable
A	0 to 10 years
B	11 to 20 years
C	21 to 35 years
D	36 to 45 years
E	46 years or older

Exhibit 3-31: Underground Cables - Age Related Score

b) Cable Design and Construction

Since PILC cable designs are known to provide significantly longer service life compared to XLPE cables and earlier vintages of XLPE cables that did not employ tree retardant designs are subject to premature failures, design of cable is employed in Health Index formulation, as indicated in the table below:

Condition Rating	Type of Treatment
A	PILC Cables
B	Tree Retardant XLPE
E	Earlier vintages of XLPE

Exhibit 3-32: Underground Cables – Design Related Health Score

c) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable Health Index formulation as indicated below:

Condition Rating	Component Condition
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures per 10 km in the last 5 years
C	1.0 to 1.5 Failures per 10 km in the last 5 years
D	1.5 to 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

Exhibit 3-33: Underground Cables – Failure Related Score

d) Condition of Cable Splices or Stress Cones

Physical condition of cable splices or stress cones can be employed in assessing overall condition of the cable circuit:

Condition Rating	Component Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

Exhibit 3-34: Underground Cables - Splice or Stress Cone Related Health Score

3.3.4. Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.3.5. Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non-functioning drains or sump pumps
- Inadequate space

(a) Structural Condition

Condition Rating	Inspections
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

Exhibit 3-35: Manhole and Vaults – Structural Health Score

(b) Flooding Incidents, Drains, Sump Pumps

Condition Rating	Inspections
A	No incidents of Flooding at this location
C	Occasional Flooding, working sump pumps and drains
E	Frequent Flooding, No sump pumps or drains

Exhibit 3-36: Manhole and Vaults - Flooding Related Health Score

(c) Vault Size and Access:

Condition Rating	Inspections
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement

Exhibit 3-37: Manholes and Vaults – Size Related Health Score

3.3.6. Health Index Formulation for Underground Cables, Manholes and Vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Cable Circuit	A – E	5	3	15
2	Type/Design of Cable	A – E	5	3	15
3	Loading of Cable Circuit	A – E	5	5	25
4	Historic Failure rates	A – E	5	8	40
5	Visual inspection of splices or stress cones	A – E	5	1	5
	Total				100

Exhibit 3-38: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Structural Integrity	A – E	5	8	40
2	Flooding and Its mitigation	A – E	5	4	20
3	Size and Access	A – E	5	8	40
	Total				100

Exhibit 3-39: Manholes and Vaults Health Index

3.4. Distribution Transformers

Four (4) main types of distribution transformers are commonly employed on distribution system:

- Pole mounted transformer
- Pad mounted transformer
- Vault transformer
- Submersible transformer

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, 120/208V, 240/416 V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.1. Ranking the Condition of Distribution Transformers through Multiple Criteria

Computing the Health Index for a distribution transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Condition Rating	Age of Distribution Transformer
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Exhibit 3-40: Distribution Transformers – Age Based Health Scoring

(b) **Condition Assessment Based on Loading Level**

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformer expressed in percentage of the nameplate rating can therefore be employed as an indicator of transformer health:

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

Exhibit 3-41: Distribution Transformers – Load Based Health Scoring

(c) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

Exhibit 3-42: Distribution Transformers – Inspections Based Health Scoring

3.4.2. Health Index Formulation for Distribution Transformers

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A – E	5	6	30
2	Peak loading	A – E	5	6	30
3	Visual inspection	A – E	5	8	40
	Total				100

Exhibit 3-43: Distribution Transformers Health Index

3.5. Disconnect Switches and Cut-outs

This asset class includes pad and vault mounted medium voltage switchgear as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Pad mounted disconnects have the following additional components:

- Pad or vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

3.4.3. Ranking Condition of Disconnect Switches through Multiple Criteria

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches, it is employed as an assessment parameter, with the following scores:

Condition Rating	Age of Disconnect Switch
A	0 to 10 years
B	10 to 20 years
C	20 to 30 years
D	30 to 40 years
E	40 years or older

Exhibit 3-44: Disconnect Switches and Cutouts – Age Based Health Scoring

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of disconnect switches. Infrared (IR) scan can provide indication of hot spots resulting from misaligned blades.

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

Exhibit 3-45: Disconnect Switches and Cutouts – Inspections Based Scoring

3.4.4. Health Index Formulation for Disconnect Switches

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of disconnect	A - E	5	10	50
2	Visual inspections and IR Scan	A - E	5	10	50
	Total				100

Exhibit 3-46: Distribution Switches and Cutouts – Health Index

4 ASSET DEMOGRAPHICS AND CONDITION ASSESSMENT

The methodology described in detail in section 3 has been used to perform an assessment of the health and condition of all major assets employed on OPUCN's distribution system. This section of the report, documents the health indices for fixed assets employed on OPUCN's distribution system, based on all available information from testing, inspections, service age and other demographic information retrieved from the GIS system.

4.1. Distribution Substations

Distribution stations step down power from 44 kV to 13.8 kV for distribution within OPUCN's service territory. There are a total of 8 distribution stations owned and operated by OPUCN. Exhibit 4-1 shows the geographic location of the distribution stations. As shown the distribution stations, located in strategic locations are well dispersed within the service territory to reliably and economically distribute power to the current customer base. Future growth in customer base is expected to take place towards the north end of the service territory, which would eventually require construction of one or two additional distribution stations at the North end of the city.

Exhibit 4-1: Municipal Station Locations

The main components of the substations include:

(a) Power Transformers
(b) 44 kV Circuit Breakers
(c) 13.8 kV Switchgear
(d) Protection Relays, Controls and Remote Terminal Units (RTUs)
(e) Control Batteries and Chargers
(f) Substation Buildings and yards
(g) Ground grids

4.1.1. Substation Transformers

Exhibit 4-2 provides detailed demographic information on power transformers, including manufacturer name, rating, service location and year of installation for each of the power transformers. Exhibit 4-3 presents the age profile of power transformers employed at OPUCN's substations. Four of the transformers, installed in substations MS5, MS7 and MS 14, have a service age of greater than 30 years.

Based on the condition assessment criteria detailed in Section 3, Health Index score has been calculated for each of the power transformers employed at substations and the results are summarized in Exhibit 4-4. As shown, based on the gas in oil analysis completed in September 2013, MS-5-T1 is determined to be in "poor" condition. This transformer has been taken out of service due to high concentration of combustible gases in oil and is scheduled to be replaced in the second quarter of 2014.

The combustible gas content in oil in Transformer MS5-T2 have also shown a modest but sudden increase during the last test and this transformer needs to be watched for health degradation during the next scheduled oil testing.

Station #	Location	Transformer #	MVA Rating	Manufacturer	Serial number	Year of Manufacture
MS #2	192 Hillcroft St	T1	25/33.3/41.7	CG Canada	RA11.0345	2012
		T2	25/33.3/41.7	CG Canada	RA11.0346	2012
MS #5	495 Stevenson Rd N	T1	20 /26.7/ 33	Ferranti Packard	39831	1984
		T2	20 /26.7/ 33	Ferranti Packard	39821	1983
MS #7	25 Taunton Rd E	T1	20 /26.7/ 33	Ferranti Packard	39811	1981
		T2	20 /26.7/ 33	Ferranti Packard	36418-1-1	1980
MS #10	36 Keewatin St. N	T1	25/33.3/41.7	Ferranti Packard	CL 60022-101-01	2004
		T2	20/26.6/33.3	Transelectrix	A32S0005	1988
MS #11	443 Bloor St E	T1	25/33.3/41.7	CG Canada	RA11.0340	2011
		T2	25/33.3/41.7	CG Canada	RA11.0341	2011
MS #13	856 Wilson Rd S	T1	25/33.3/41.7	CG Canada	RA11.0342	2011
		T2	25/33.3/41.7	CG Canada	RA11.0346	2012
MS #14	139 Court St	T1	20/26.6/33.3	Ferranti Packard	1-4229	1979
		T2	20 /26.7/ 33	Maloney electric	3424-1	1978
MS #15	1430 Harmony Rd N	T1	25/33.3/41.7	CG Canada	RA11.0344	2012
		T2	25/33.3/41.7	CG Canada	RA11.0343	2012

Exhibit 4-2: Substation Transformers Detailed Demographic Information

Exhibit 4-3: Substation Transformers Age Profile

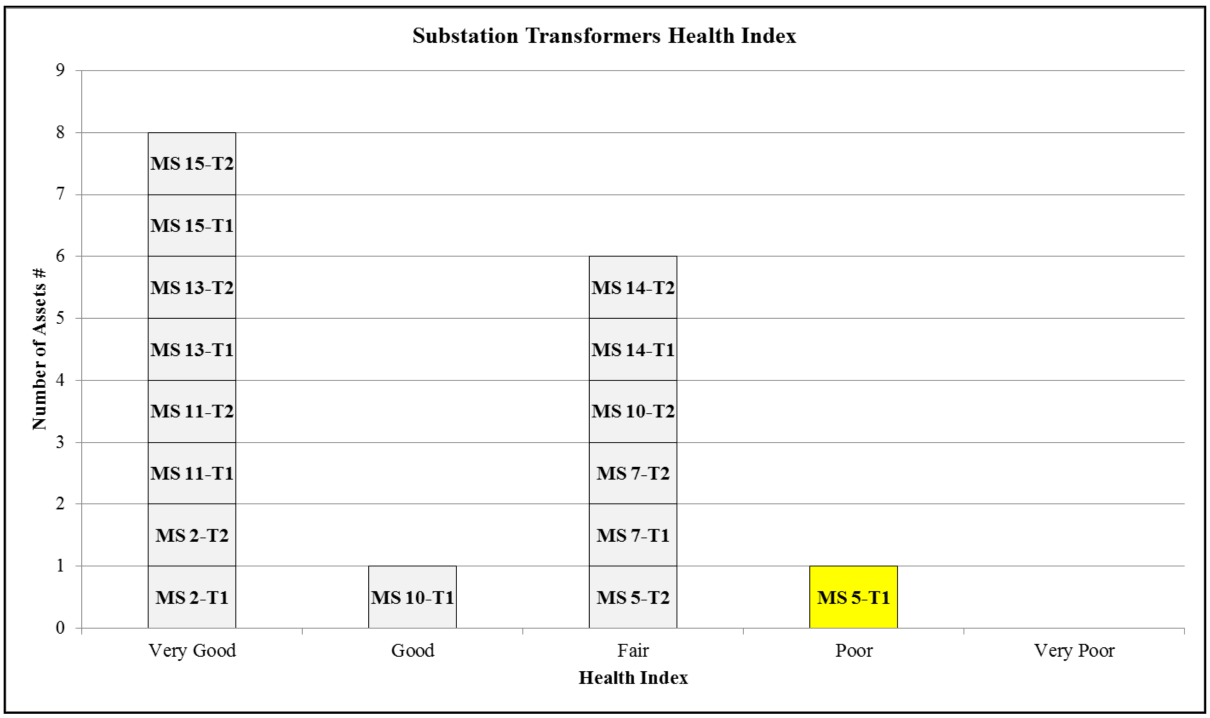


Exhibit 4-4: Substation Transformers Health Index

4.1.2. Substation Circuit Breakers

a) 44kV Circuit Breakers

The 44 kV circuit breakers at each of the substations employ virtually identical designs for outdoor oil circuit breakers. Exhibit 4-5 presents the age profile of the 44 kV circuit breakers.

All of the 44 kV circuit breakers are outdoor type oil-circuit breakers. This circuit breaker design technology has virtually become obsolete and breakers of this type have not been in manufacture for more than 25 years. The three newest breakers in service are now 29 years old but some of the older breakers have already reached service life of 45 years. OPUCN will have difficulty obtaining parts for these breakers as the existing fleet gets older and requires repairs.

The breaker counter readings indicate about a million operations for some breakers and about 100,000 operations for some others; clearly these are not correct readings and the counters are not recording correctly. Insulating oil is regularly tested and the recent test results confirm satisfactory condition of insulating oil. The operating mechanisms of breakers have not been tested for timing tests and the breaker contact resistance is not known. These breakers are rarely called upon to operate and therefore. The wear and tear from use is expected to be relatively low, but the consequences of circuit breaker failure in service are high. The health indices for 44 kV circuit breakers, based on circuit breaker age/vintage, oil tests and visual inspections, are summarized in Exhibit 4-6.

We are recommending all breakers with poor and very poor health index be replaced during the next five years.

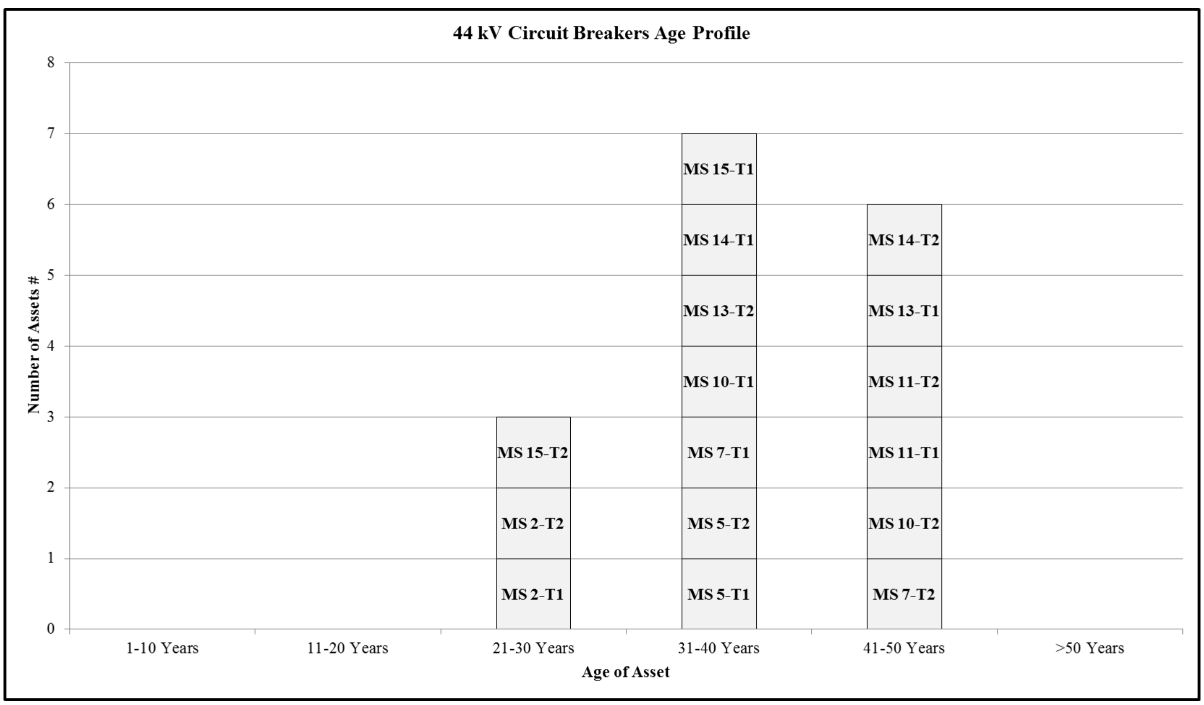


Exhibit 4-5: 44 kV Substation Circuit Breakers Age Profile

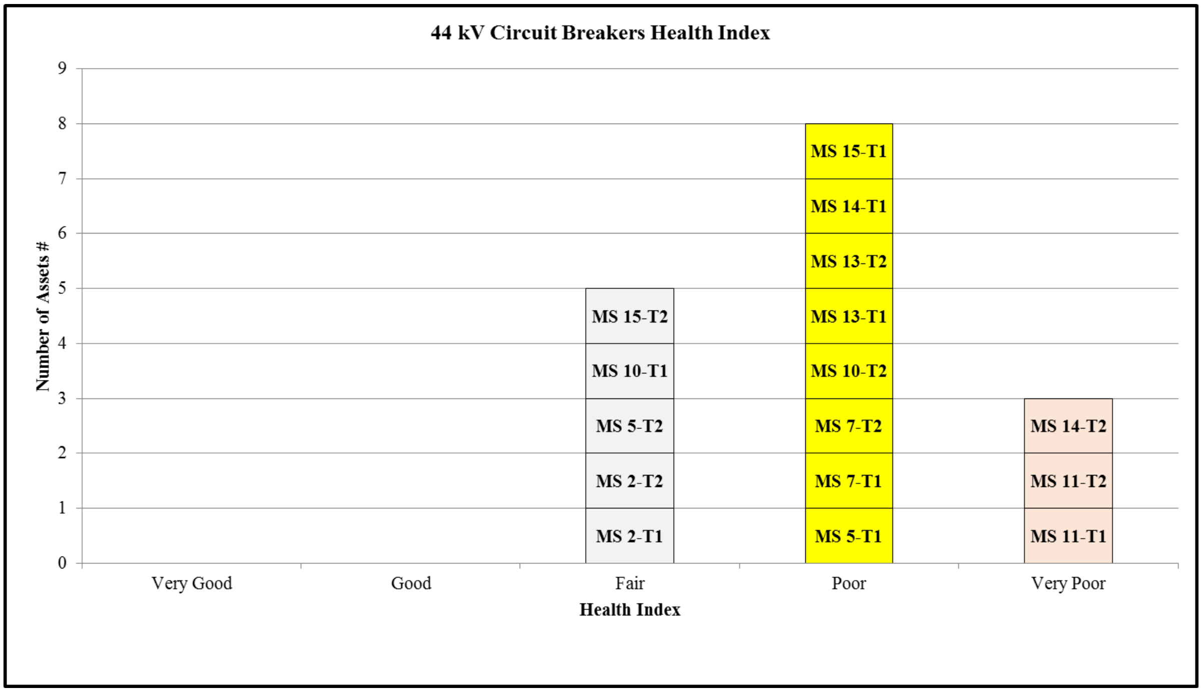


Exhibit 4-6: 44 kV Substation Circuit Breakers Health Index

b) 13.8kV Circuit Breakers

On the 13.8 kV bus, each substation has nine circuit breakers, two incomings breakers, one tie breaker and six feeder breakers. For the eight substations, there are a total 72 - 15 kV class circuit breakers in metal clad switchgear employed at different substations. The original circuit breakers were of magnetic air design type. In 2007 OPUCN embarked on a program to replace the aging magnetic air breakers with modern vacuum circuit breakers within existing switchgear cells. This method has proven to be a cost effective and reliable method for breaker replacement based on OPUCN's experience of six years. While a majority of the magnetic-air circuit breakers have now been replaced with vacuum breakers, the remaining few are scheduled for replacement during 2014-2016.

Exhibit 4-7 presents the Health Indices of all the 13.8kV circuit breakers. We recommend all breakers with poor and very poor health index be replaced during the next five years.

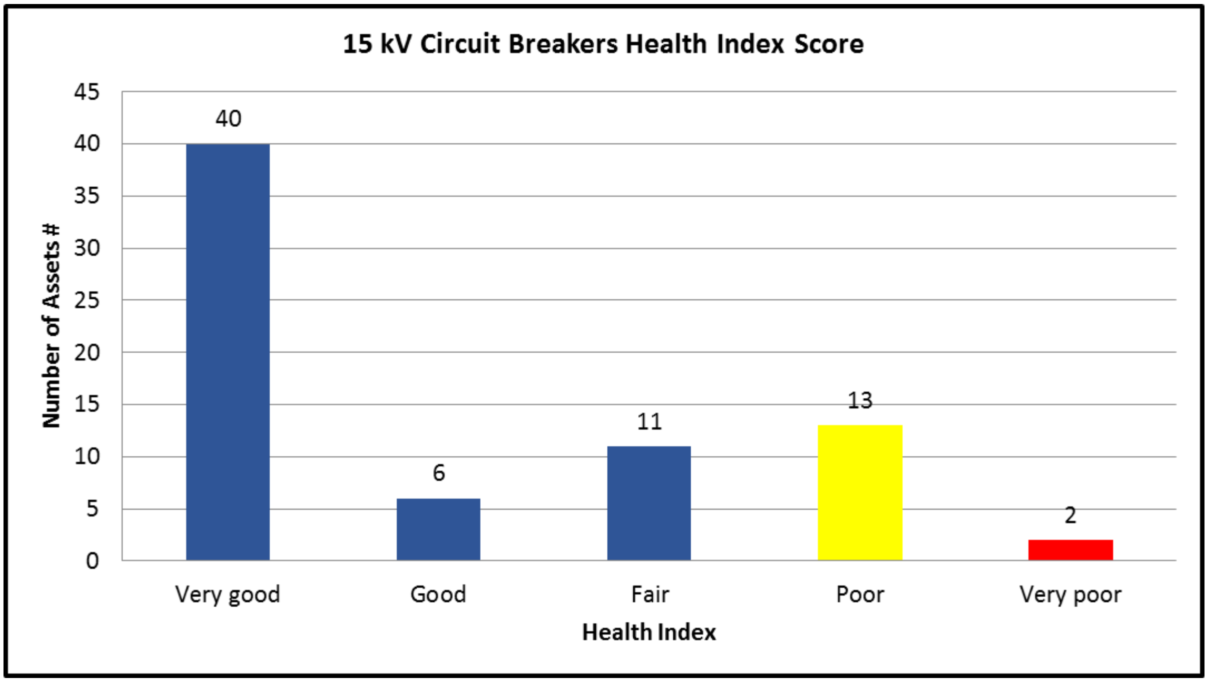


Exhibit 4-7: 13.8 kV Substation Circuit Breakers Health Indices

4.1.3. Substation RTUs

The original RTUs at each of the stations were installed in 1991 and in 2006 the CPU boards were updated. As shown in Exhibit 4-8, the Remote Terminal Units (RTU) of all the substations of Oshawa PUCN are determined to be in "fair" condition and do not require any additional upgrades during the next five year period.

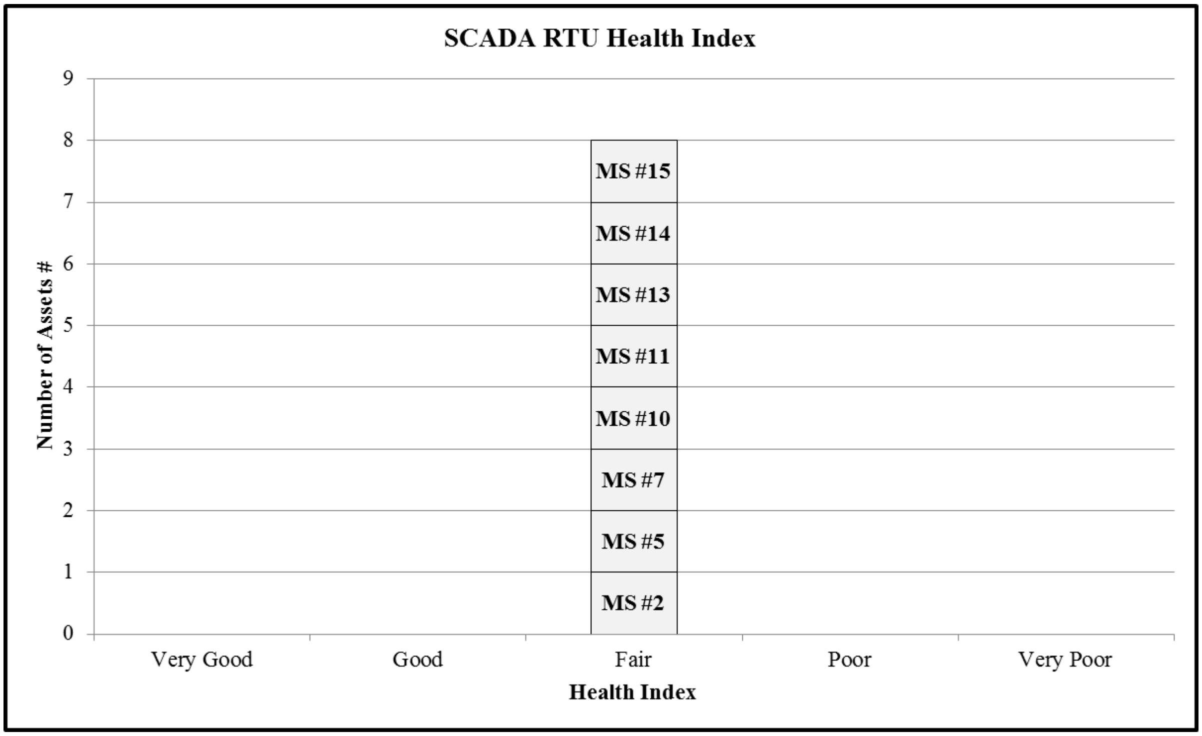


Exhibit 4-8: Substation SCADA RTU Health Index

4.1.4. Substation Batteries and Chargers

OPCUN has standardized its substation batteries to BAE SECURA lead acid batteries and STATICON chargers. This battery/charger system generally provides a service life of about 12 years. As shown in Exhibit 4-9, with the exception of substation MS-5 (installed in 2004), the batteries and chargers at the remaining stations have been determined to be in “good” or “very good” condition. Based on the service age, the battery and charger at MS-5 may need replacement during the next five year period.

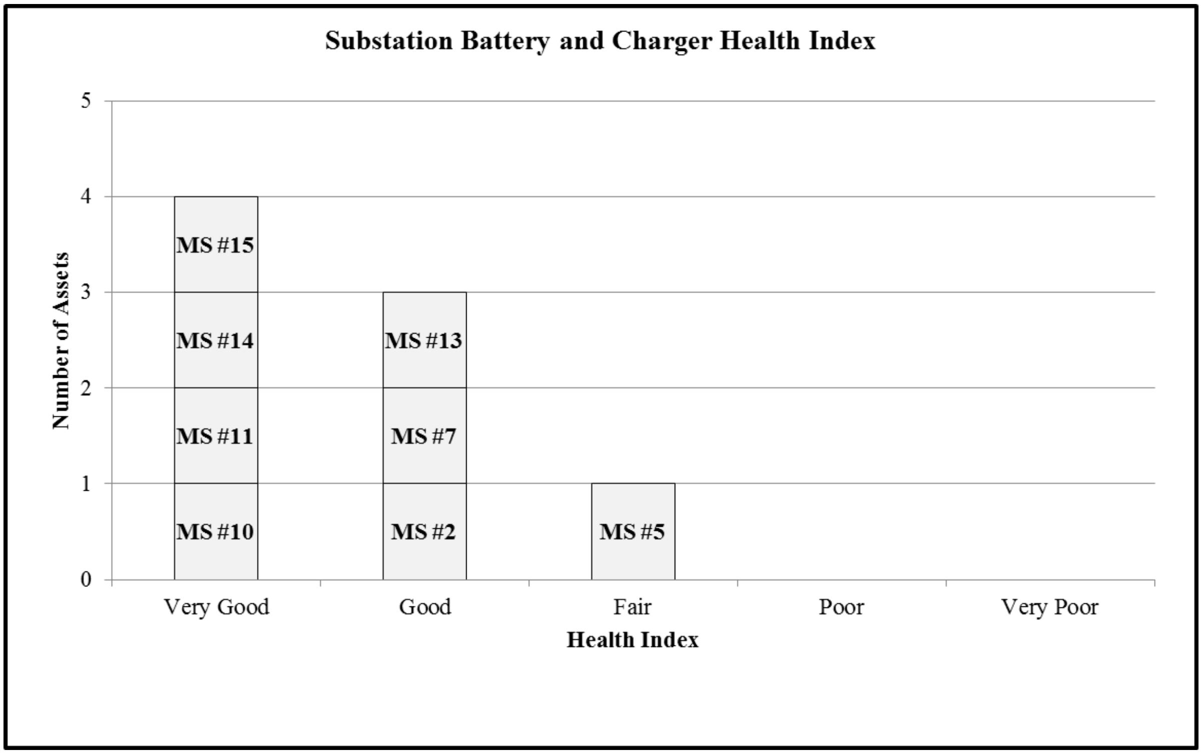


Exhibit 4-9: Substation Battery and Chargers Health Index

4.1.5. Substation Ground Grids

The ground grids at MS2, MS11 and MS15 were tested by OPUCN in 2011 and found in good condition. There are no records available of ground grid testing for the remaining five substations and it is not possible to determine the effectiveness of ground grid at these remaining stations, without testing of the ground grids.

The Health Indices provided in Exhibit 4-10 for ground grids is based on visual inspections. We recommend the ground grids at each of the remaining stations be tested to determine their condition and effectiveness.

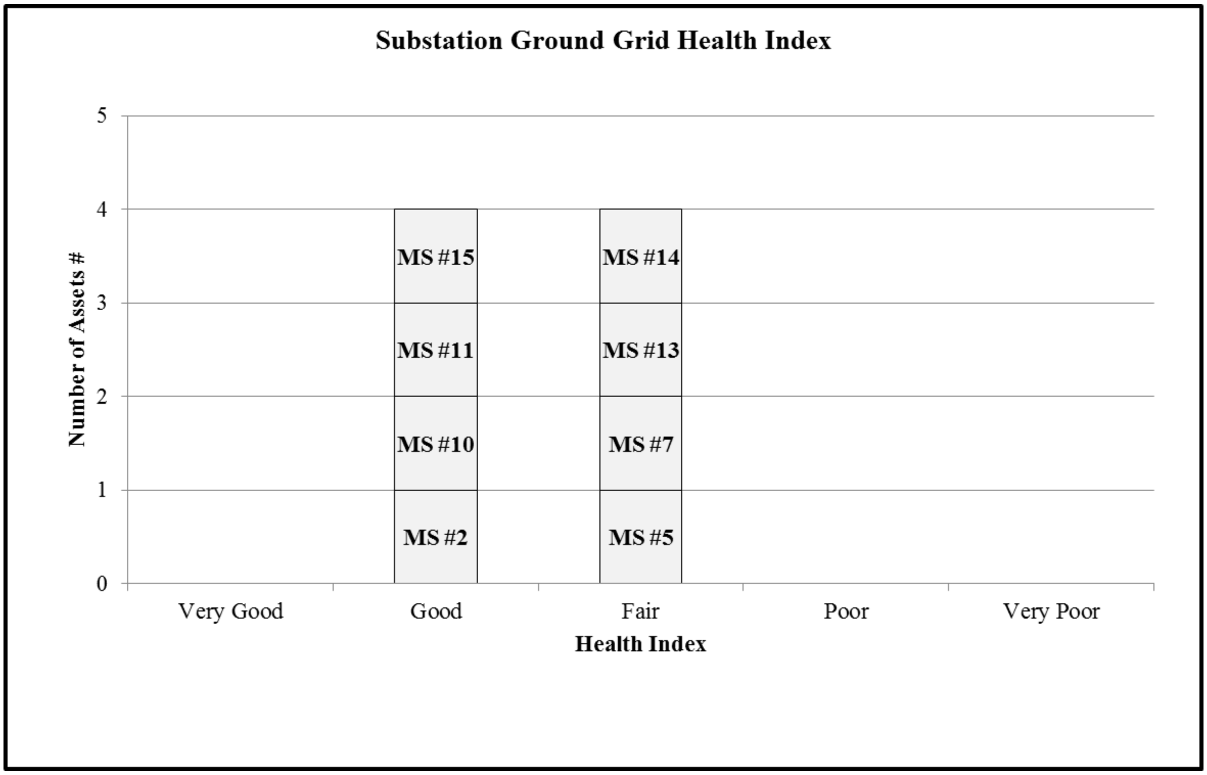


Exhibit 4-10: Substation Ground Grids Health Index

4.1.6. Substation Buildings and Civil Works

Based on the condition assessment criteria defined in Section 3, the Health Indices as summarized in Exhibit 4-11, is calculated for substation buildings. MS-14 is ranked to be in fair condition. All the substation buildings are found to be in “good” or “very good” conditions.

No capital investment is required into any of the substation buildings during the next five years.

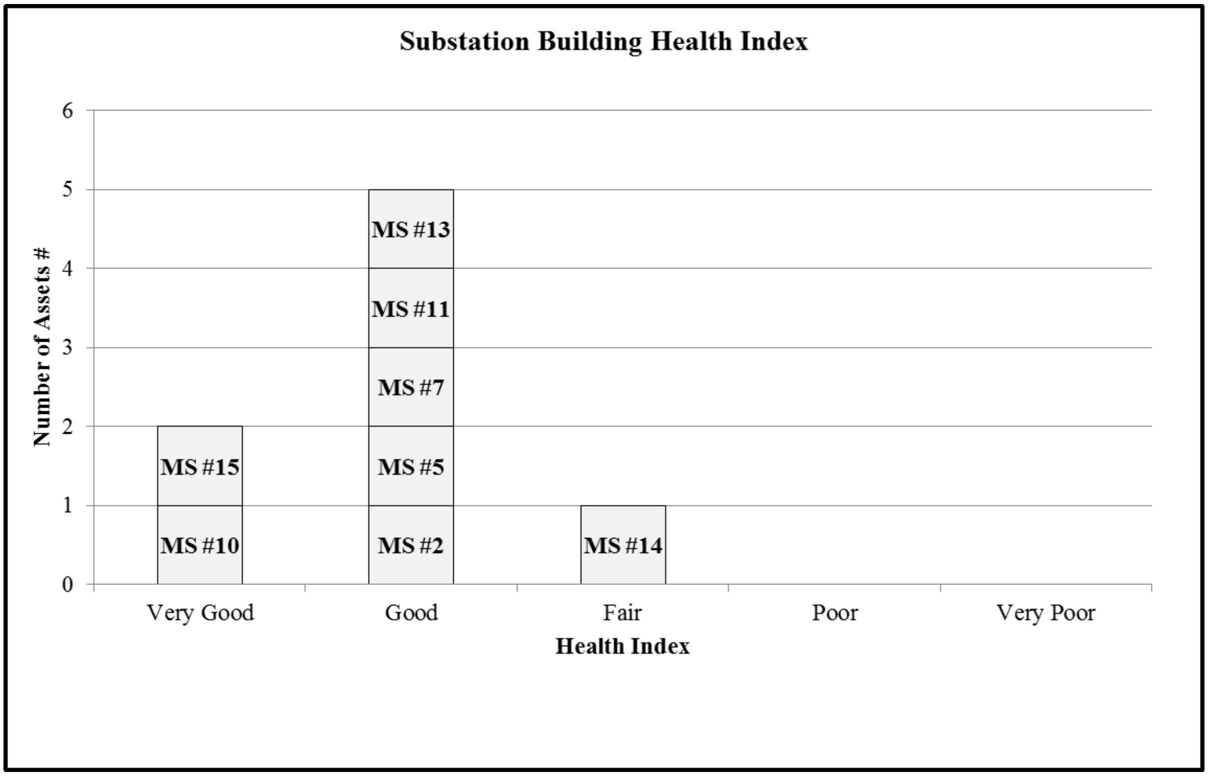


Exhibit 4-11: Substation Buildings Health Index

4.1.7. Substation Feeder Cables

Based on the condition assessment criteria defined in Section 3, the Health Indices as summarized in Exhibit 4-12 and Exhibit 4-13, is calculated for feeder cables connecting the station breaker to the overhead line. Cables at MS-14 are found to be in poor condition and will require replacement in the next five years.

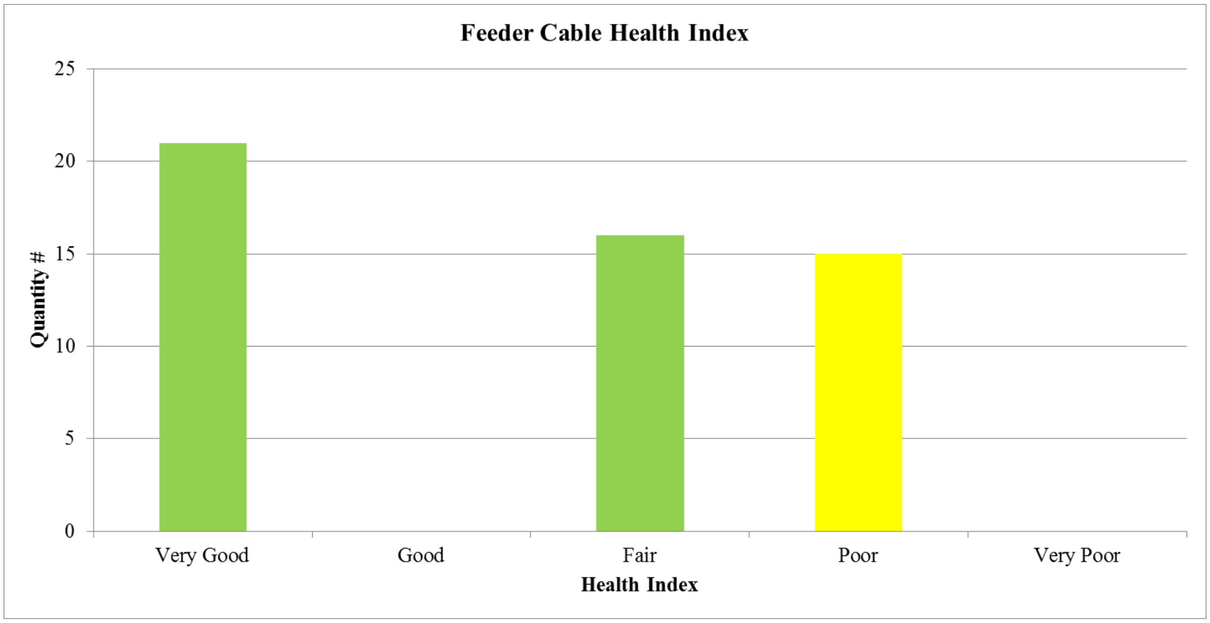


Exhibit 4-12: Feeder Cables Health Index

	Health Index
MS2 - F1 Breaker	Fair
MS2 - F2 Breaker	Fair
MS2 - F3 Breaker	Fair
MS2 - F4 Breaker	Very Good
MS2 - F5 Breaker	Fair
MS2 - F6 Breaker	Fair
MS5 - F1 Breaker	Poor
MS5 - F2 Breaker	Fair
MS5 - F3 Breaker	Fair
MS5 - F4 Breaker	Fair
MS5 - F5 Breaker	Poor
MS5 - F6 Breaker	Fair
MS5 - 52M5 T1 44kv	Poor
MS5 - 54M5 T2 44KV	Fair
MS7 - F1 Breaker	Very Good
MS7 - F2 Breaker	Very Good
MS7 - F3 Breaker	Very Good
MS7 - F4 Breaker	Very Good
MS7 - F5 Breaker	Very Good
MS7 - F6 Breaker	Very Good
MS10 - F1 Breaker	Poor
MS10 - F2 Breaker	Fair
MS10 - F3 Breaker	Fair
MS10 - F4 Breaker	Fair
MS10 - F5 Breaker	Poor
MS10 - F6 Breaker	Poor
MS11 - F1 Breaker	Very Good
MS11 - F2 Breaker	Very Good
MS11 - F3 Breaker	Very Good
MS11 - F4 Breaker	Very Good
MS11 - F5 Breaker	Very Good
MS11 - F6 Breaker	Very Good
MS13 - F1 Breaker	Very Good
MS13 - F2 Breaker	Very Good
MS13 - F3 Breaker	Very Good
MS13 - F4 Breaker	Very Good
MS13 - F5 Breaker	Very Good
MS13 - F6 Breaker	Very Good
MS14 - F1 Breaker	Poor
MS14 - F2 Breaker	Poor
MS14 - F3 Breaker	Poor
MS14 - F4 Breaker	Poor
MS14 - F5 Breaker	Poor
MS14 - F6 Breaker	Poor
MS15 - F1 Breaker	Poor
MS15 - F2 Breaker	Poor
MS15 - F3 Breaker	Poor
MS15 - F4 Breaker	Fair
MS15 - F5 Breaker	Fair
MS15 - F6 Breaker	Fair
MS15 - 54M7 T1 44kv	Very Good
MS15 - 54M1 T2 44KV	Very Good

Exhibit 4-13: Feeder Cables Health Index

4.2. Overhead Lines

4.2.1. 13.8kV Distribution Line Support Poles

The distribution network at Oshawa PUCN employs 44 kV feeders that transfer power from the two (2) Hydro One owned Transformer Stations (TS) to municipal distribution stations (MS) or customer owned distribution stations. 13.8 kV feeders begin at municipal substations and supply distribution transformers mounted on poles, pads or in equipment vaults. Other than the 44 kV and 13.8 kV medium voltage lines, there are no other voltage levels in use on MV circuits. The low voltage circuits supplied from the distribution transformers include (a) 120/240 V 1-ph circuits to serve residential or small commercial customers; (b) 120/208 V 3-ph circuits to serve commercial customers and (c) 347/600 V 3-ph circuits to serve commercial and industrial customers. The 3-phase overhead line circuits serve as either the main trunk lines or 3-phase branch circuits on 44 kV and 13.8 kV lines. Many pole lines support multiple circuits at various voltage levels.

Based on the demographic information retrieved from the GIS system, there are approximately 11,397 poles in service on OPUCN's electricity distribution system. These include approximately 10,914 wood poles, 463 concrete poles, and 20 steel poles.

Exhibit 4-14 displays the age profile of all wood poles in service in the OPUCN electricity distribution system. Approximately 295 poles (shown in red) have been in service for more than 50 years and approximately 754 poles (shown in yellow) have been in service for more than 40 years. Considering the typical life expectancy of wood poles to be approximately 45 years, approximately 1050 poles will require replacement during the next 6 years (including 2014).

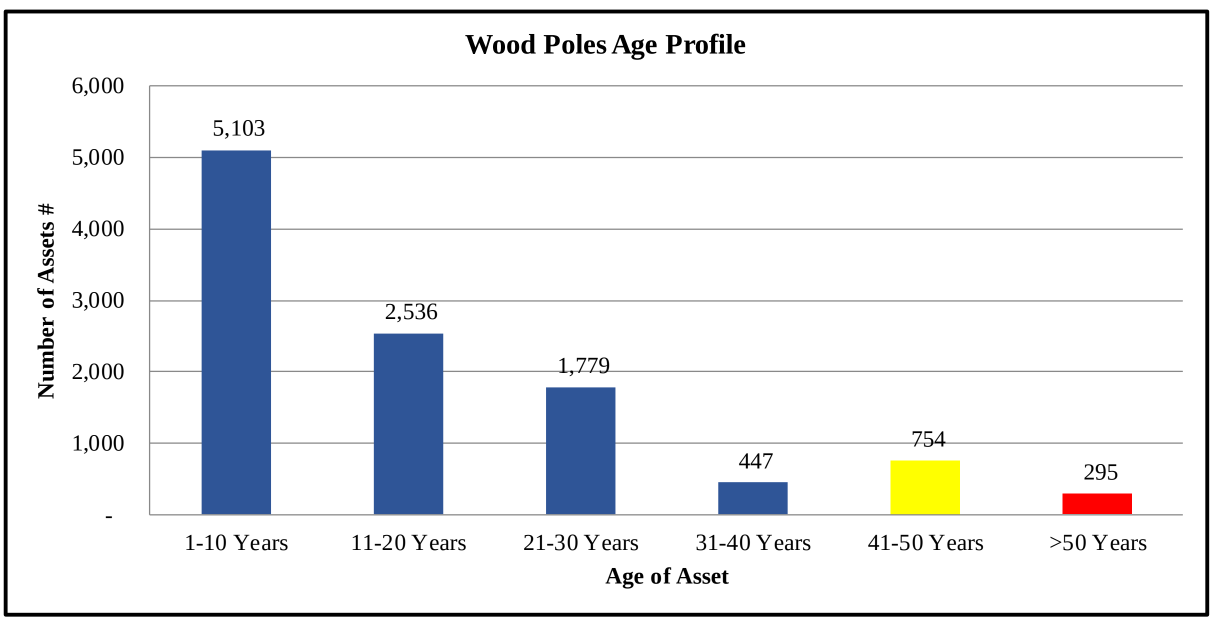


Exhibit 4-14: Age Demographics of Wood Poles

Poles on distribution lines are employed in different configurations; some support only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. Exhibit 4-15 indicates the approximate percentage of different pole heights employed on OPUCN's distribution system. As indicated, a majority of the poles vary in height from 30 feet to 80 feet, however, 35ft, 40ft and 45ft poles are used most commonly.

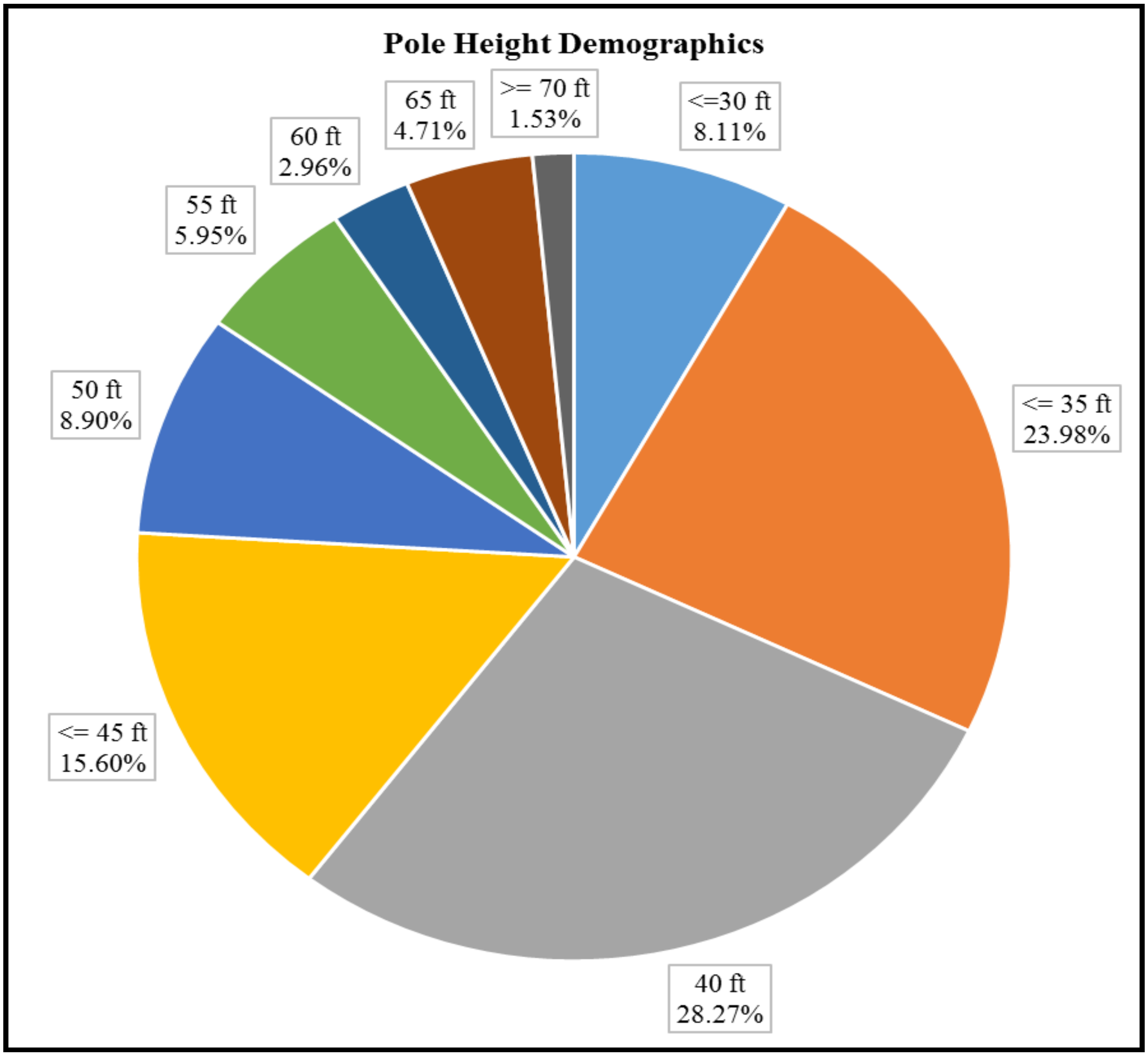


Exhibit 4-15: Distribution Poles Height Demographics

While more than 90% of the poles in service are wood poles, there are approximately 480 other types of poles (including steel and concrete) employed on OPUCN's electricity distribution system. Exhibit 4-16 displays the age profile of concrete poles employed on the OPUCN distribution system. The concrete poles are known to provide a useful service life of the order of 60 years and it is not expected many concrete poles would require replacement over the next five years.

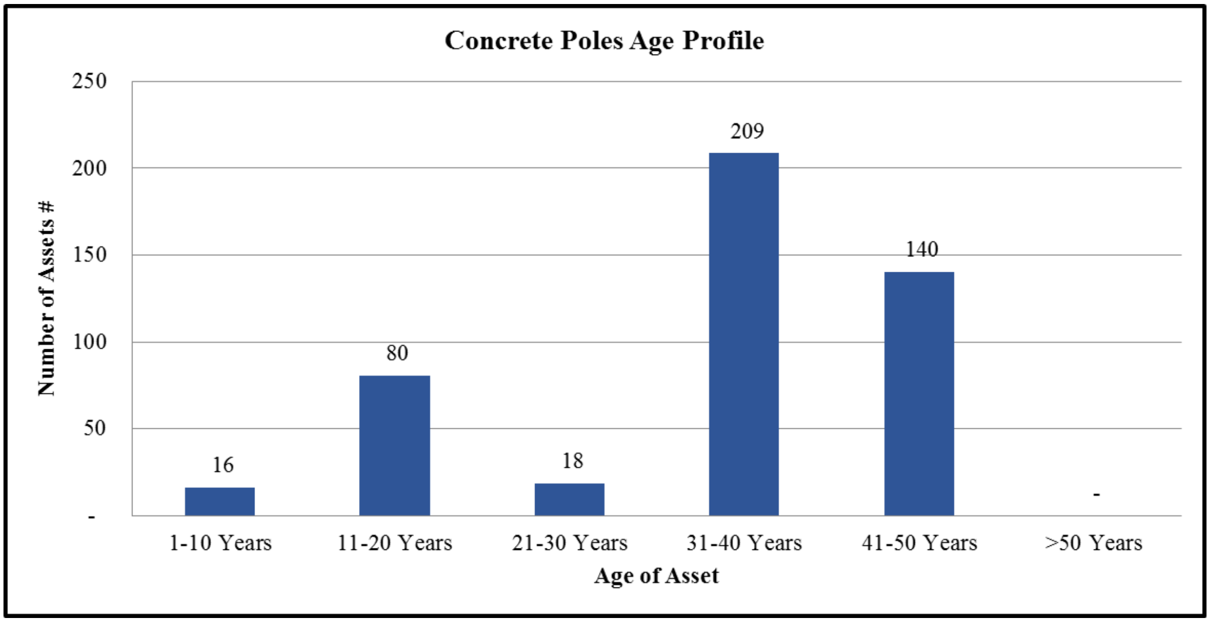


Exhibit 4-16: Age Demographics of Concrete Poles

Exhibit 4-17 displays the age profile of steel poles employed on the Oshawa PUCN distribution system. There are a total of 20 steel poles in operation. All of them have a service age of less than 20 years.

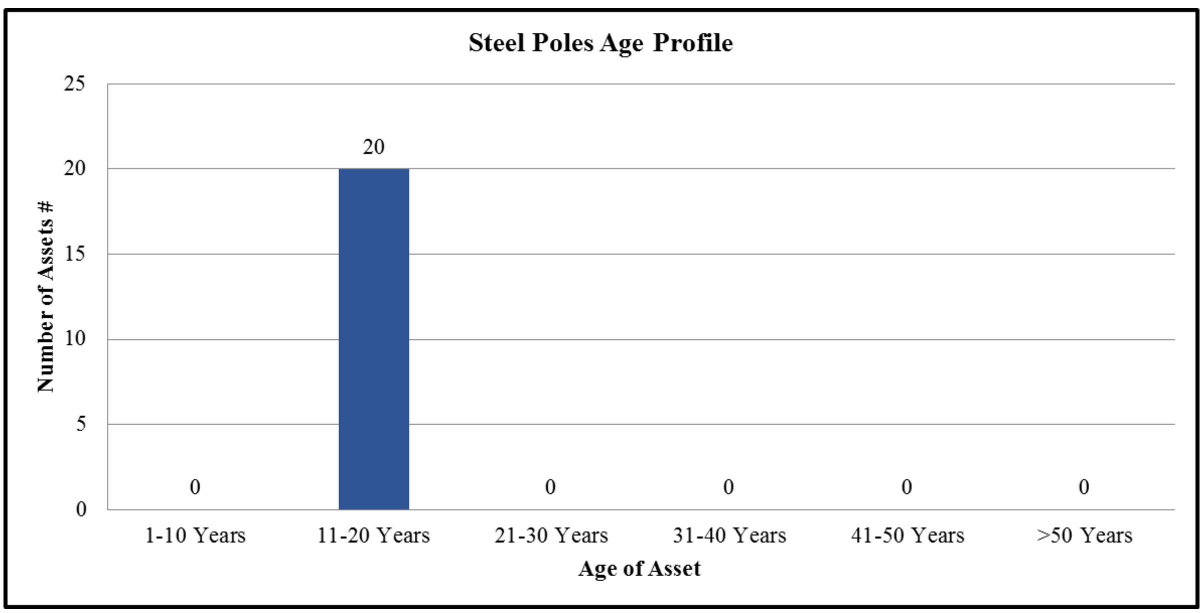


Exhibit 4-17: Age Demographics of Steel Poles

4.2.2. Health Index for Wood Poles

By taking into account the age and results of field inspections, we have determined the health indices for all distribution wood poles and the results are indicated in Exhibit 4-18. In case of concrete and steel poles, there are no poles determined to be in poor or very poor condition.

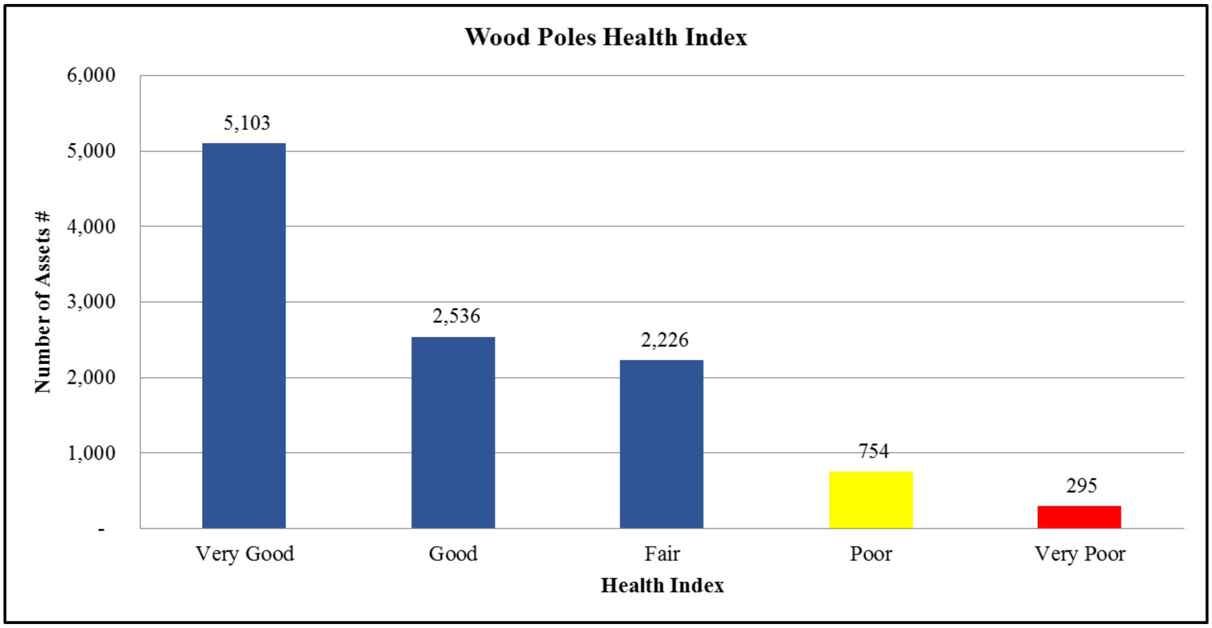
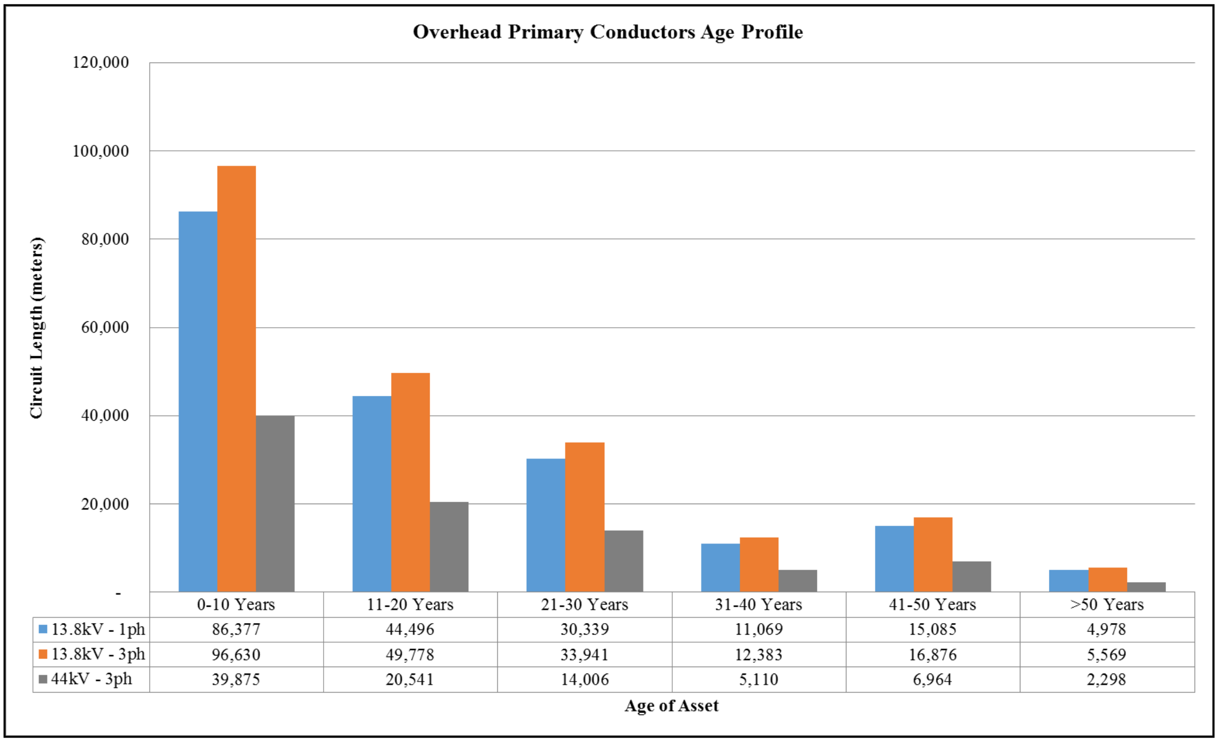


Exhibit 4-18: Wood Poles Health Index

4.2.3. Overhead Primary Conductors

The overhead distribution network of OPUCN employs approximately 215 kilometers of 3-ph, 13.8 kV, approximately 192 km of 1-ph 13.8 kV and approximately 88 km of 3-ph, 44 kV lines. The age profile for conductors is not known, but since OPUCN constructs all lines using new poles, new conductors, new insulators and hardware, we have assigned the age profile to line conductors to match the age profile of poles.

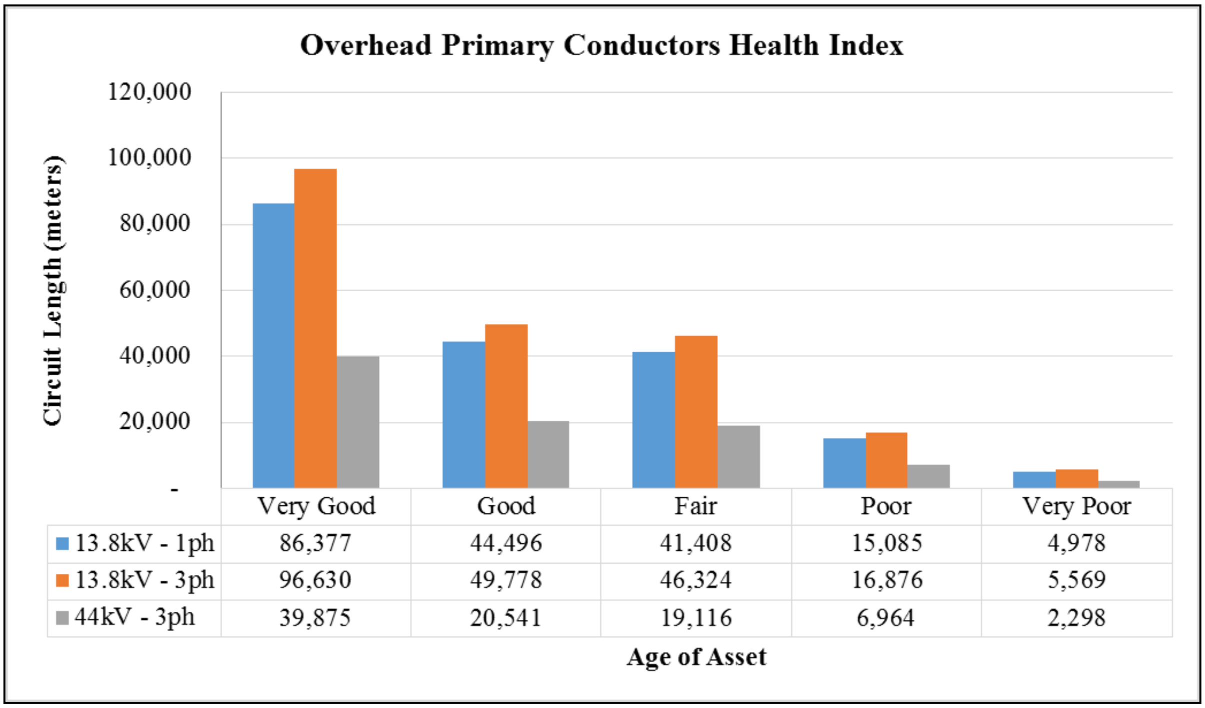
Exhibit 4-19 shows the age profile for overhead line conductors.



	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
13.8kV - 1ph	86,377	44,496	30,339	11,069	15,085	4,978
13.8kV - 3ph	96,630	49,778	33,941	12,383	16,876	5,569
44kV - 3ph	39,875	20,541	14,006	5,110	6,964	2,298

Exhibit 4-19: Age Demographics of Overhead Circuits

Based on the age profile, the heath index score for the conductors is presented in Exhibit 4-20.



	Very Good	Good	Fair	Poor	Very Poor
13.8kV - 1ph	86,377	44,496	41,408	15,085	4,978
13.8kV - 3ph	96,630	49,778	46,324	16,876	5,569
44kV - 3ph	39,875	20,541	19,116	6,964	2,298

Exhibit 4-20: Health Index Score of Overhead Circuits

4.2.4. Small Size Conductor Risk on Overhead Lines

The current standard requires the 13.8 kV lines to be constructed with aluminum wires, and a majority of the 13.8 kV lines constructed during the last 30 – 35 years employ aluminum conductors. However, there are many old 13.8 kV lines with copper conductors, still in service. Many of these circuits employ small size #6 conductors which have low tensile strength and are vulnerable to conductor breakage and pose a serious impact to system reliability.

Exhibit 4-21 and Exhibit 4-22 show the feeder by feeder breakdown of the circuit lengths of 3-phase and 1-phase lines strung with # 6 copper. These lines will need to be rebuilt to current standards with aluminum conductors, to mitigate failure and reliability risks.

We recommend the small size conductors on 3-phase and 1-phase lines be replaced over the next 10 year period.

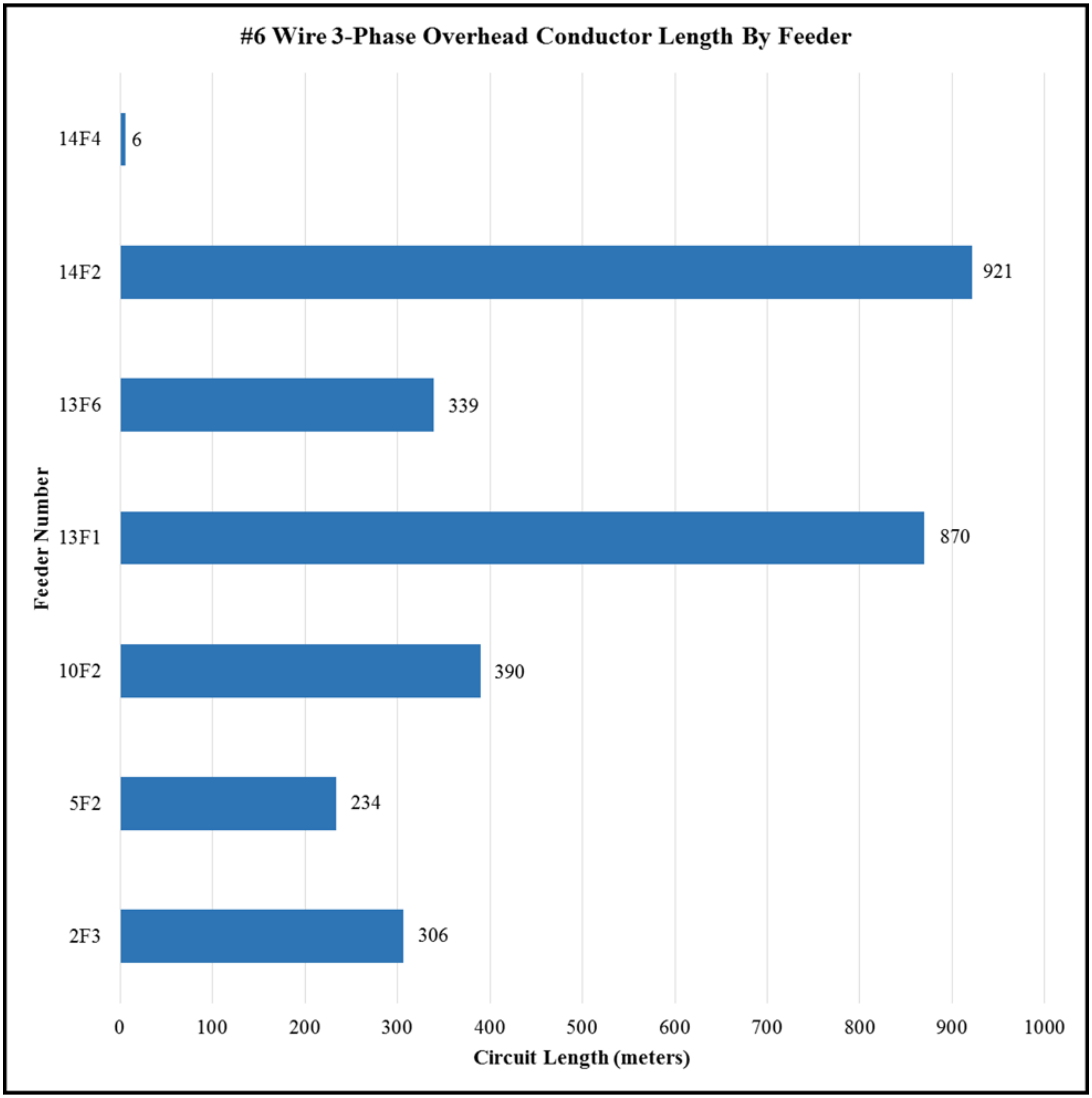


Exhibit 4-21: Line Lengths of #6 Copper Wire on 3-Phase Overhead Lines

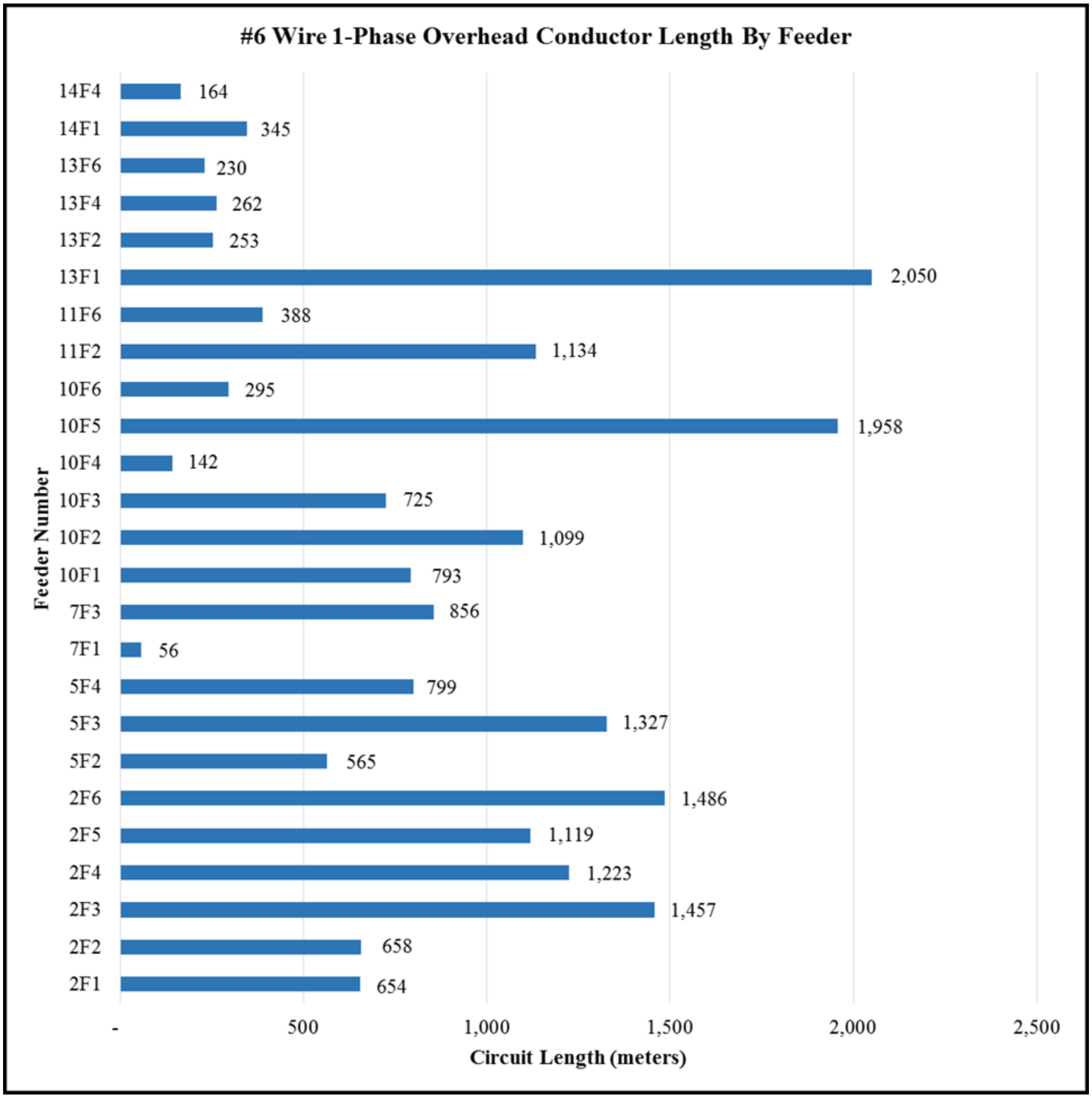
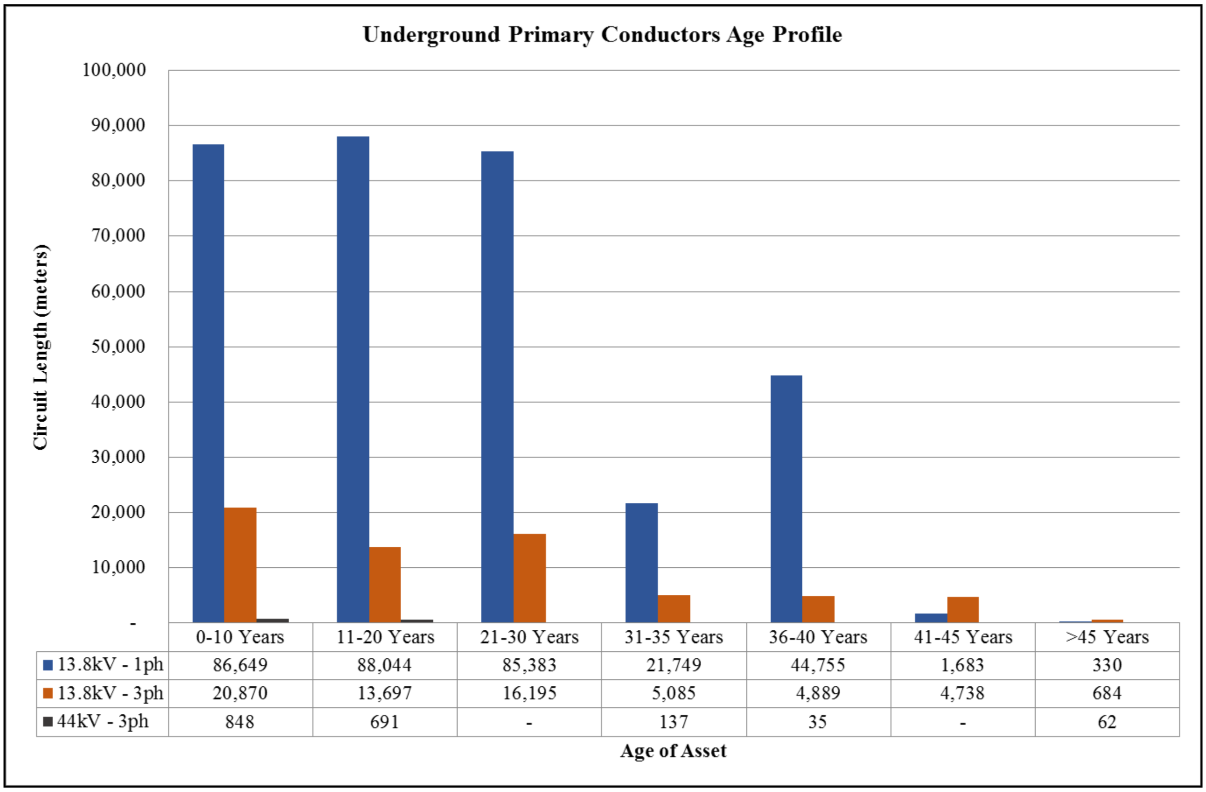


Exhibit 4-22: Line Lengths of #6 Copper Wire on 1-Phase Overhead Lines

4.3. Underground Distribution System

4.3.1. Primary Underground Cables

The underground distribution network of Oshawa PUCN employs approximately 395 kilometers of 13.8 kV underground cables and approximately 1.7 kilometers of 44 kV cables. The overall age profile of underground cables in service is presented in Exhibit 4-23. Approximately 7.5 km of cable circuits have a service age of greater than 40 years.



	0-10 Years	11-20 Years	21-30 Years	31-35 Years	36-40 Years	41-45 Years	>45 Years
13.8kV - 1ph	86,649	88,044	85,383	21,749	44,755	1,683	330
13.8kV - 3ph	20,870	13,697	16,195	5,085	4,889	4,738	684
44kV - 3ph	848	691	-	137	35	-	62

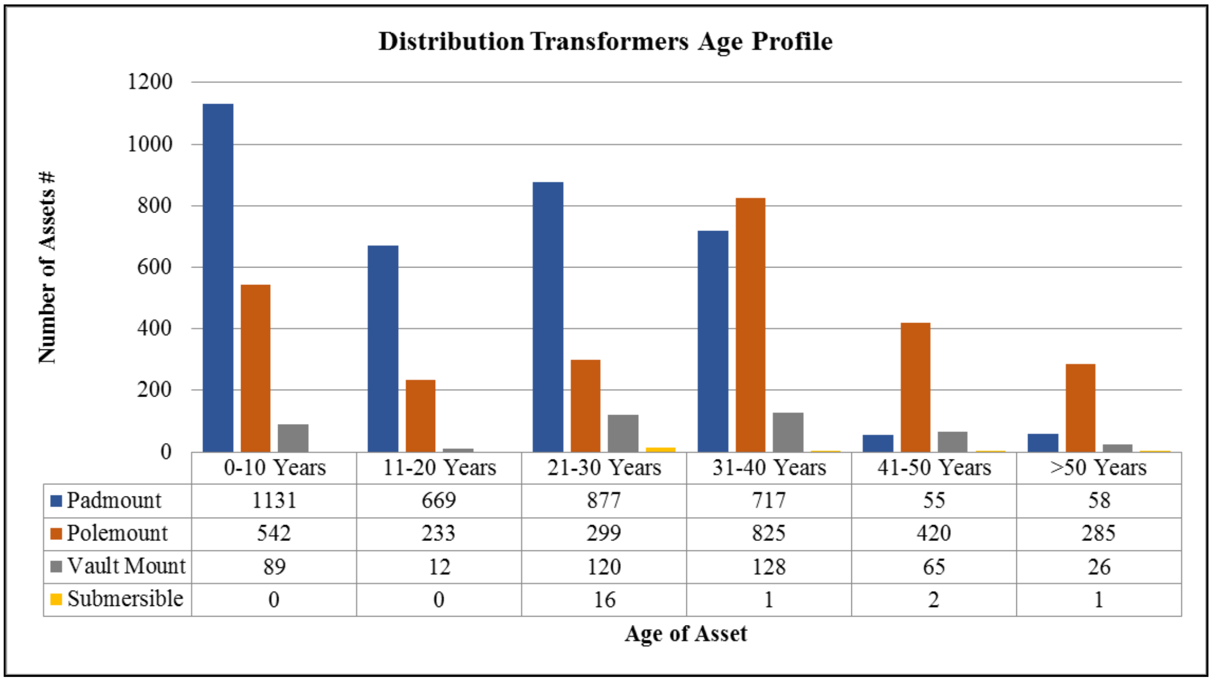
Exhibit 4-23: Total Age Demographics of Underground Conductors

Although the underground cables are not experiencing wide spread failures, to mitigate the risk of in-service failures, OPUCN retained independent contractors to assess the condition of older vintage cables. Two types of in-situ tests were performed on representative samples of older vintage cables – with service life of approximately 40 years – partial discharge (PD) measurements and DOBLE tests (tan δ measurements). The tests revealed mixed results: while some of the cable tests indicate significant degradation in insulation, some other cable circuits were found to be in good condition. The circuits with degraded insulation were replaced in 2013.

Since failure of underground cables can significantly impact reliability and the XLPE cables have typical useful life of 35 to 40 years, it would be prudent for OPCUN to budget for replacement of the cable circuits with service life of more than 40 years. The prioritization of underground circuits for cable replacement could be determined based on the number of failures.

4.4. Distribution Transformers

Exhibit 4-24 is a graphical representation of the overall age profile for distribution transformers. Oshawa PUCN has 4 different types of transformers in service: Pad-mount, Pole-mount, Submersible and Vault type and the numbers of transformer in each category are indicated in Exhibit 4-25.



	0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Padmount	1131	669	877	717	55	58
Polemount	542	233	299	825	420	285
Vault Mount	89	12	120	128	65	26
Submersible	0	0	16	1	2	1

Exhibit 4-24: Distribution Transformers Age Profiles

Exhibit 4-25 represents a complete picture of the distribution transformer ratings and types employed on OPUCN distribution system.

Description	Total Installed Quantity	Asset Age (in years)					
		0-10 Years	11-20 Years	21-30 Years	31-40 Years	41-50 Years	>50 Years
Padmount							
50kVA, 1-ph	2069	808	526	358	356	10	11
75kVA, 1-ph	7	2	0	0	4	0	1
100kVA, 1-ph	741	100	68	337	182	9	45
150kVA, 1-ph	2	2	0	0	0	0	0
167kVA, 1-ph	164	38	3	11	112	0	0
300kVA, 1-ph	2	2	0	0	0	0	0
500kVA, 1-ph	1	1	0	0	0	0	0
75kVA, 3-ph	39	7	14	9	4	5	0
112kVA, 3-ph	4	0	0	0	0	4	0
150kVA, 3-ph	162	41	15	77	18	11	0
225kVA, 3-ph	5	0	0	0	2	3	0
300kVA, 3-ph	165	49	26	61	22	6	1
450kVA, 3-ph	3	0	0	0	1	2	0
500kVA, 3-ph	68	29	11	21	7	0	0
750kVA, 3-ph	37	33	4	0	0	0	0
1000kVA, 3-ph	36	18	1	3	9	5	0
1500kVA, 3-ph	2	1	1	0	0	0	0
Padmount Total	**3507**	**1131**	**669**	**877**	**717**	**55**	**58**
Polemount							
5kVA, 1-ph	3	0	0	0	0	2	1
10kVA, 1-ph	92	0	4	0	17	35	36
15kVA, 1-ph	30	2	0	0	14	10	4
25kVA, 1-ph	770	340	89	49	72	147	73
37kVA, 1-ph	85	0	0	0	14	45	26
50kVA, 1-ph	802	153	83	63	336	117	50
75kVA, 1-ph	259	10	0	4	182	41	22
100kVA, 1-ph	561	37	57	183	190	21	73
150kVA, 1-ph	2	0	0	0	0	2	0
Polemount Total	**2604**	**542**	**233**	**299**	**825**	**420**	**285**
Vault Mount							
25kVA, 1-ph	3	0	0	0	0	3	0
37kVA, 1-ph	3	0	0	0	0	3	0
50kVA, 1-ph	75	16	0	5	33	17	4
75kVA, 1-ph	27	6	0	0	4	14	3
100kVA, 1-ph	79	11	6	26	25	1	10
150kVA, 1-ph	2	0	0	0	0	2	0
167kVA, 1-ph	62	27	0	11	15	9	0
250kVA, 1-ph	54	0	0	15	24	12	3
333kVA, 1-ph	21	15	3	0	0	3	0
450kVA, 1-ph	1	0	0	0	0	0	1
500kVA, 1-ph	3	0	0	0	3	0	0
50kVA, 3-ph	4	0	0	1	0	0	3
75kVA, 3-ph	3	0	0	0	3	0	0
100kVA, 3-ph	3	0	0	3	0	0	0
167kVA, 3-ph	3	0	0	3	0	0	0
250kVA, 3-ph	31	6	0	13	12	0	0
333kVA, 3-ph	28	7	0	18	3	0	0
500kVA, 3-ph	34	0	3	25	6	0	0
600kVA, 3-ph	1	0	0	0	0	0	1
1000kVA, 3-ph	1	0	0	0	0	1	0
2000kVA, 3-ph	2	1	0	0	0	0	1
Vault Mount Total	**440**	**89**	**12**	**120**	**128**	**65**	**26**
Submersible							
50kVA, 1-ph	17	0	0	15	0	1	1
100kVA, 1-ph	3	0	0	1	1	1	0
Submersible Total	**20**	**0**	**0**	**16**	**1**	**2**	**1**

Exhibit 4-25: Distribution Transformers Age Profiles

Based on the information obtained from the GIS system, health indices of distribution transformers presented in Exhibit 4-26 have been calculated based on service age alone, because there is no other information available to determine the condition or useful remaining life of distribution transformers.

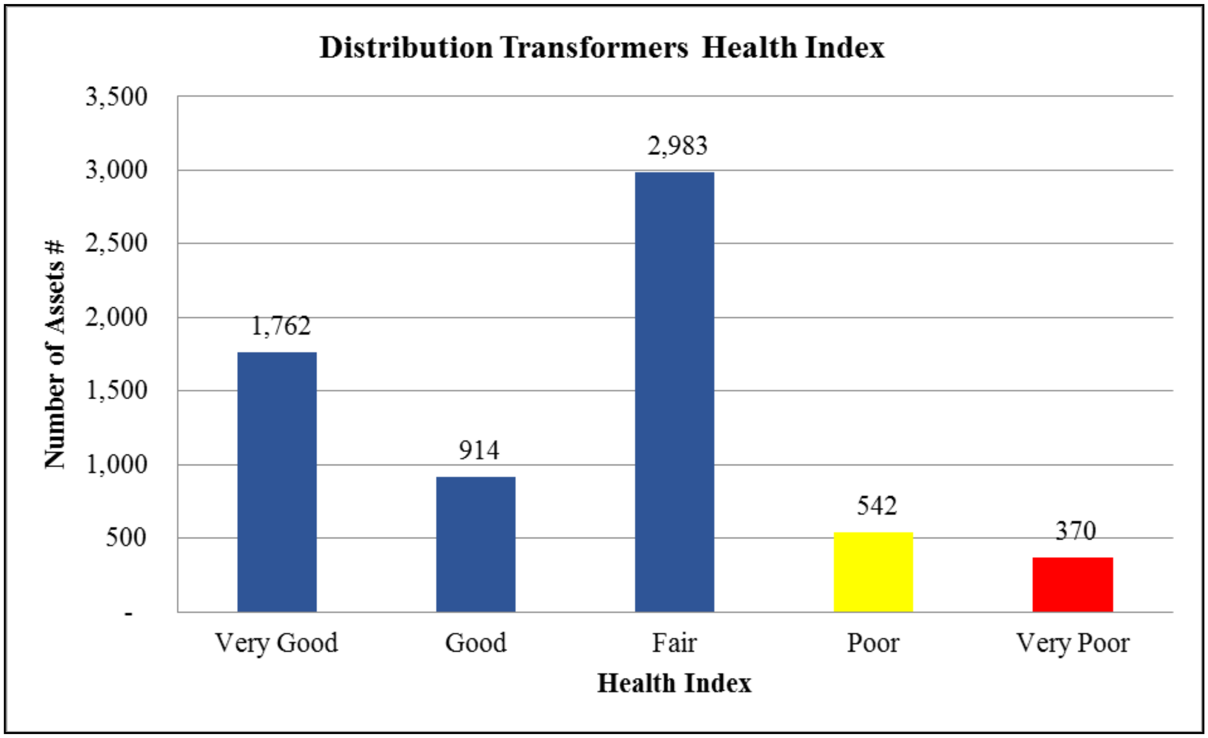


Exhibit 4-26: Distribution Transformers Health Indices

OPUCN employs "run-to-failure" strategy for distribution transformers, due to the relatively low impact of transformer failures on reliability. But when the transformers with serious deficiencies are identified through inspections, these are immediately replaced. This strategy is in line with all other LDCs and is recommended to be continued.

4.5. Distribution Switches

Oshawa PUCN`s distribution system is well equipped for disconnecting and isolating, load-breaking, and fault interrupting and to provide means of isolation during power interruptions. A majority of the line switches are pole-mounted type. The age data for the Overhead switches is not available. The total number of switches is indicated in Exhibit 4-27. The line switches are generally replaced during reconstruction a feeder.

Switch Type	Quantity #
Air Break Type	20
Mid-Span Opener	30
Load Break	44
In Line	508

Exhibit 4-27: Overhead Switches Age Profile

4.6. Overhead 1-Phase Fuse Cut-outs

Fuse cutouts are pole-mounted switching devices, used to disconnect or reconnect pole mounted equipment to the line, such as distribution transformers or underground laterals. Porcelain insulated cutouts have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, i.e. line insulators, arresters and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" was causing insulators to crack. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) caused stresses on the porcelain. These stresses caused small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator. Cracked porcelain cutouts can also results in pole fires resulting in more extensive plant replacement.

Transmission insulators and distribution insulators had been the focus of the industry's attention throughout most of the 1980's and 1990's, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain. During the past several years many utilities throughout North America have seen increasing failures of their porcelain insulated cutouts. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cutout. Cement growth is the likely cause of the initial cracks. The breakage of porcelain insulated cutouts is a concern from a safety and reliability perspective. During cutout operation the porcelain can break causing the cutout to separate into two parts. This creates a hazard to line personnel operating the cutout and can cause outages to customers.

Multiple Canadian utilities in the Atlantic region including Nova Scotia Power, Maritime Electric and New Brunswick Power have experienced similar problems with porcelain cutouts during the past few years. Throughout North America, utilities such as B.C. Hydro, American Electric Power and Public Service Electric & Gas have been concerned with the increased rise in the number of cutouts failing on their distribution systems. A survey of Canadian utilities conducted in 2001 by B.C. Hydro identifies the increasing concern of several utilities about this trend.

In May 2005, a cutout failure in the service territory of Connecticut Light & Power Co. resulted in a fire that destroyed a Dunkin' Donuts restaurant and four cars in Farmington. During testimony at the state Department of Public Utility Control investigation, CL&P presented evidence that said the company's experience with A.B. Chance cutouts is that they fail at a higher rate than cutouts manufactured by competitor S&C Electric. They claimed a study in 2000 determined that two S&C cutouts, out of 84,000 purchased, had failed during the previous decade, yielding a failure rate of 0.002 percent. During the same period, 42 A.B. Chance cutouts, out of 66,000 purchased, had failed. That yielded a failure rate of 0.06 percent, a failure rate 30 times higher than the failure rate of S&C cutouts. During a follow-up study in 2005, the A.B. Chance numbers were even worse; the failure rate had increased to 1.3 to 1.4 percent. CL&P spent $4.5 million a year over the next three years to remove every A.B. Chance porcelain cutout from its system and replace them with polymer insulators. The common industry solution to this problem has been replacement of the porcelain insulated cutouts with polymer insulated cutouts, as shown in Exhibit 4-28.

Exhibit 4-28: Porcelain (Left) and Polymer (Right) Insulated Cut-outs

Oshawa PUCN has also been experiencing repeated failures of porcelain fused cutouts during the past several years. Some failures have resulted in electrical failure of the insulation, while other cases the insulator has cracked and broken resulting in pole fires. Although no serious accident has occurred so far, the failing cutouts do present a high risk of injury to public or utility employees.

OPUCN has adopted a program under which porcelain cut-outs are being systematically replaced with polymer cut-outs to mitigate safety risks. This program will continue during the next five years, until all the high risk insulators have been replaced. Exhibit 4-29 shows demographic information on fused cutouts employed by Oshawa PUCN.

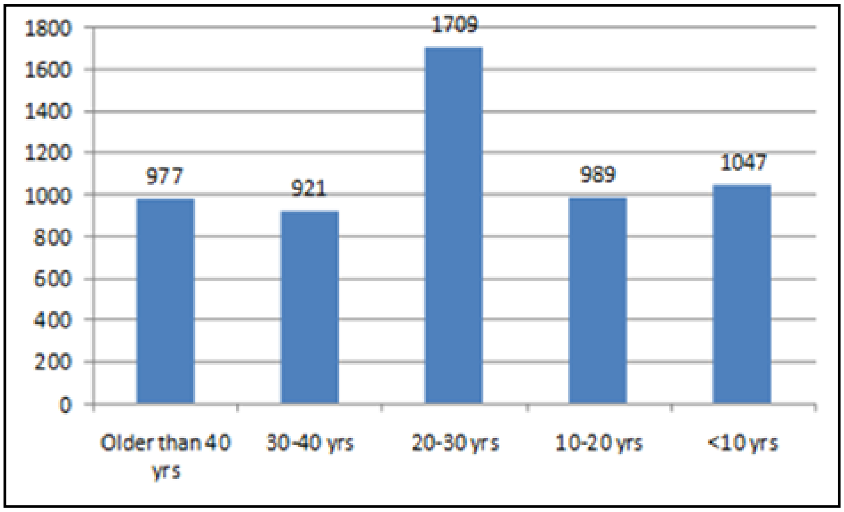


Exhibit 4-29: Fused Cut-Outs Demographics

4.7. Equipment Vaults

Equipment vaults are employed for installation of distribution transformers and primary switchgear to serve commercial loads. In downtown core, a majority of the equipment vaults are installed under sidewalks and submersible equipment is used. In many commercial building the vault is provided by building owners in which Oshawa PUC Network equipment is installed. While in downtown core, power to the vaults is supplied through an underground manhole duct system, most vaults outside of the downtown core are supplied through short laterals, either installed in a duct or in direct buried configuration. There are approximately 150 vaults on OPUCN's network equipment. A condition assessment scoring methodology has been developed and each of the vaults assessed in accordance with this methodology. Individual vault condition assessment results are tabulated in Appendix A.

The downtown core of Oshawa is undergoing major renewal, which is expected to continue over the coming years, with existing low rise buildings being replaced with higher density buildings, requiring more power. The City of Oshawa Economic Development department has forecasted significant development in the downtown area and it continues to promote new businesses development in the downtown core.

The developments in the downtown core have already started. The University of Ontario, Institute of Technology (UOIT) has started to move some of its campus facilities into the downtown core and their plan is to continue moving their operations into downtown during the next five years. The distribution system in the downtown core needs to be upgraded to meet the power needs of high rise buildings.

Lack of duct space and small sized manholes present a major bottleneck for capacity upgrades and expansion of the underground system in the downtown core to serve the new developments. In order to serve the load growth, OPUCN needs to expand the downtown duct bank system to facilitate capacity upgrades.

5 ASSET MANAGEMENT PLAN - CAPITAL AND MAINTENANCE INVESTMENTS

Based on the condition assessment of major assets employed in substations, overhead lines and underground distribution system, this section provides the budgetary estimates of capital investments required during the next six years from 2014 to 2019 to keep the system operating at optimal levels. All cost estimates presented in the report are in 2013 dollars, and do not include inflation impacts. Recommendations for a preventative maintenance program are also provided.

5.1. Overhead Lines

In order to keep the risk of in-service equipment failure at acceptable level and to mitigate deterioration in supply system reliability, Exhibit 5-1 provides budgetary estimates for replacement of 1-ph and 3-ph overhead lines expected to reach the end of their useful service life during the next six years.

	Circuit length Requiring Replacement during next 6 years (meters)	Averge Unit Cost		Total Cost		
		Material	Labor	Material	Labor	Total
13.8kV 3-PhaseOverhead Line Circuits (includes small conductor lines)	24,000	$ 125.00	$ 105.00	$ 2,999,944.05	$ 2,519,953.00	$ 5,519,897.06
44kV 3-Phase Overhead Line Circuits	9,262	$ 135.00	$ 110.00	$ 1,250,352.57	$ 1,018,805.80	$ 2,269,158.36
13.8kV 1-Phase Overhead Line Circuits (Includes small conductor lines)	30,088	$ 55.00	$ 55.00	$ 1,654,840.33	$ 1,654,840.33	$ 3,309,680.66
Total Overhead Line Investment Requirement				$ 5,905,136.95	$ 5,193,599.13	$ 11,098,736.07
Overhead Line Investment per year				$ 984,189.49	$ 865,599.85	$ 1,849,789.35

Exhibit 5-1: Capital Investment Needs – OH Lines

Methodology provided in Section 3 is recommended to be employed for prioritization of the line sections for asset renewal.

5.2. Underground Cable System

Based on the condition of existing overhead lines described in Section 4, and in order to prevent deterioration in supply system reliability due to excessive cable failures, Exhibit 5-2 provides budgetary estimates for replacement of 1-ph and 3-ph cables expected to reach the end of their service life during the next six years.

	Requiring Replacement during next 6 years (meters)	Averge Unit Cost		Total Cost		
		Material	Labor	Material	Labor	Total
13.8kV 3-Phase Underground Cable Circuits	6,941	$ 50.00	$ 130.00	$ 347,056.92	$ 902,347.99	$ 1,249,404.91
13.8kV 1-Phase Underground Cable Circuits	30,515	$ 20.00	$ 115.00	$ 610,297.76	$ 3,509,212.09	$ 4,119,509.85
Total Undeground System Investment Requirement				$ 957,354.68	$ 4,411,560.09	$ 5,368,914.76
Underground System Investment per year				$ 159,559.11	$ 735,260.01	$ 894,819.13

Exhibit 5-2: Capital Investment Needs - U/G Cables

5.3. Disconnect Switches and Cut-outs

Based on the condition assessment of disconnect switches and cut-outs described in Section 4, the quantities of disconnect switches and fused cut-outs expected to reach the end of their service life during the next 10 years and the level of capital investments required for their replacement is provided in Exhibit 5-3. These include disconnect switches installed in vaults and pad-mounted applications as well as cut-outs and in-line switches installed on poles.

	Requiring Replacement during next 6 years	Unit Cost		Total Cost		
		Material	Labor	Material	Labor	Total
15 kV 1-ph Cutouts	2100	$ 200.00	$ 300.00	$ 420,000.00	$ 630,000.00	$ 1,050,000.00
15 kV ILS switches	60	$ 500.00	$ 500.00	$ 30,000.00	$ 30,000.00	$ 60,000.00
15 kV 3-ph Fused Disconnects	10	$ 2,000.00	$ 1,200.00	$ 20,000.00	$ 12,000.00	$ 32,000.00
Total invesment Required over next 6 years				$ 470,000.00	$ 672,000.00	$ 1,142,000.00
Annual invesment required (complete in 3 years)				$ 156,666.67	$ 224,000.00	$ 380,666.67

Exhibit 5-3: Capital Investment Needs – Disconnect Switches and Cut-outs

5.4. *Pole-mounted Transformers*

By taking into account the service age of distribution transformers, Exhibit 5-4 provides budgetary estimates for replacement of pole mounted transformers during the next five years, after they have failed in service.

	LV	Requiring Replacement During Next 6 years	Unit Cost		Total Cost		
			Material	Labor	Material	Labor	Total
Pole mounted 5 kVA, 1-ph	120/240	3	$ 2,000	$ 1,500	$ 6,000	$ 4,500	$ 10,500
Pole mounted 10 kVA, 1-ph	120/240	67	$ 2,000	$ 1,500	$ 134,000	$ 100,500	$ 234,500
Pole mounted 15 kVA, 1-ph	120/240	12	$ 2,000	$ 1,500	$ 24,000	$ 18,000	$ 42,000
Pole mounted 25 kVA, 1-ph	120/240	183	$ 2,000	$ 1,500	$ 366,000	$ 274,500	$ 640,500
Pole mounted 37 kVA, 1-ph	120/240	68	$ 2,000	$ 1,500	$ 136,000	$ 102,000	$ 238,000
Pole mounted 50 kVA, 1-ph	120/240	166	$ 3,000	$ 1,500	$ 498,000	$ 249,000	$ 747,000
Pole mounted 75 kVA, 1-ph	120/240	63	$ 3,500	$ 1,500	$ 220,500	$ 94,500	$ 315,000
Pole mounted 100 kVA, 1-ph	120/240	94	$ 4,500	$ 1,500	$ 423,000	$ 141,000	$ 564,000
Pole mounted 150 kVA, 1-ph	120/240	2	$ 9,000	$ 1,500	$ 18,000	$ 3,000	$ 21,000
Total	120/240	658			$ 1,825,500	$ 987,000	$ 2,812,500
Pole mounted 10 kVA, 1-ph	600	4	$ 2,000	$ 1,500	$ 8,000	$ 6,000	$ 14,000
Pole mounted 15 kVA, 1-ph	600	2	$ 2,000	$ 1,500	$ 4,000	$ 3,000	$ 7,000
Pole mounted 25 kVA, 1-ph	600	37	$ 2,000	$ 1,500	$ 74,000	$ 55,500	$ 129,500
Pole mounted 37 kVA, 1-ph	600	3	$ 3,000	$ 1,500	$ 9,000	$ 4,500	$ 13,500
Pole mounted 50 kVA, 1-ph	600	1	$ 3,500	$ 1,500	$ 3,500	$ 1,500	$ 5,000
Total	600	47			$ 98,500	$ 70,500	$ 169,000
Total Investment Required over 6 years					$ 1,924,000	$ 1,057,500	$ 2,981,500
Annual Investment Required					$ 320,667	$ 176,250	$ 496,917

Exhibit 5-4: Capital Investment Needs – Pole-mounted Transformers

5.5. *Pad-mounted Transformers*

Exhibit 5-5 provides budgetary estimates for replacement of pad mounted transformers that may need replacement after failure in service, during the next 5 years. These include both 1-ph and 3-ph transformers for 208 V and 600 V.

	LV	Requiring Replacement During Next 6 years	Unit Cost		Total Cost		
			Material	Labor	Material	Labor	Total
Padmount 50 kVA, 1-ph	120/240	21	$ 4,500	$ 2,500	$ 94,500	$ 52,500	$ 147,000
Padmount 75kVA, 1-ph	120/240	1	$ 5,500	$ 2,500	$ 5,500	$ 2,500	$ 8,000
Padmount 100 kVA, 1-ph	120/240	54	$ 6,000	$ 2,500	$ 324,000	$ 135,000	$ 459,000
Total	120/240	76			$ 424,000	$ 190,000	$ 614,000
Padmount 75 kVA, 3-ph	120/208	5	$ 7,000	$ 3,000	$ 35,000	$ 15,000	$ 50,000
Padmount 112 kVA, 3-ph	120/208	1	$ 8,000	$ 3,100	$ 8,000	$ 3,100	$ 11,100
Padmount 150 kVA, 3-ph	120/208	7	$ 10,000	$ 3,200	$ 70,000	$ 22,400	$ 92,400
Padmount 225 kVA, 3-ph	120/208	2	$ 18,000	$ 3,500	$ 36,000	$ 7,000	$ 43,000
Padmount 300 kVA, 3-ph	120/208	5	$ 20,000	$ 2,500	$ 100,000	$ 12,500	$ 112,500
Padmount 450 kVA, 3-ph	120/208	1	$ 25,000	$ 4,200	$ 25,000	$ 4,200	$ 29,200
Total	120/208	21			$ 274,000	$ 64,200	$ 338,200
Padmount, 112 kVA	347/600	3	$ 8,000	$ 2,300	$ 24,000	$ 6,900	$ 30,900
Padmount, 150kVA, 3-ph	347/600	4	$ 10,000	$ 2,500	$ 40,000	$ 10,000	$ 50,000
Padmount 225 kVA, 3-ph	347/600	1	$ 18,000	$ 3,500	$ 18,000	$ 3,500	$ 21,500
Padmount 300 kVA, 3-ph	347/600	2	$ 20,000	$ 4,000	$ 40,000	$ 8,000	$ 48,000
Padmount 450 kVA, 3-ph	347/600	1	$ 25,000	$ 4,200	$ 25,000	$ 4,200	$ 29,200
Total	347/600	11			$ 147,000	$ 32,600	$ 179,600
Total Investment Required over 6 years					$ 845,000	$ 286,800	$ 1,131,800
Annual Investment Required					$ 140,833	$ 47,800	$ 188,633

Exhibit 5-5: Capital Investment Needs – Pad-mounted Transformers

5.6. *Vault-Type Transformers*

Exhibit 5-6 provides budgetary estimates for replacement of vault mounted transformers after failure in service, during the next 5 years.

		Requiring Replacement During Next 6 years	Unit Cost		Total Cost		
			Material	Labor	Material	Labor	Total
Vault mounted 25 kVA, 1-ph	120/240	3	$ 2,500	$ 2,500	$ 7,500	$ 7,500	$ 15,000
Vault mounted 37 kVA, 1-ph	120/240	3	$ 3,000	$ 3,000	$ 9,000	$ 9,000	$ 18,000
Vault mounted 50 kVA, 1-ph	120/240	21	$ 3,500	$ 3,500	$ 73,500	$ 73,500	$ 147,000
Vault mounted 75 kVA, 1-ph	120/240	17	$ 5,000	$ 3,500	$ 85,000	$ 59,500	$ 144,500
Vault mounted 100 kVA, 1-ph	120/240	11	$ 6,500	$ 3,500	$ 71,500	$ 38,500	$ 110,000
Vault mounted 150 kVA, 1-ph	120/240	2	$ 7,000	$ 3,500	$ 14,000	$ 7,000	$ 21,000
Vault mounted 167 kVA, 1-ph	120/240	9	$ 7,000	$ 3,500	$ 63,000	$ 31,500	$ 94,500
Vault mounted 333 kVA, 1-ph	120/240	3	$ 12,000	$ 4,500	$ 36,000	$ 13,500	$ 49,500
Vault mounted 250kVA, 1-ph	120/240	15	$ 10,000	$ 4,000	$ 150,000	$ 60,000	$ 210,000
Total		84			$ 509,500	$ 300,000	$ 809,500
Vault mounted 1000kVA, 3-ph	120/208	1	$ 20,000	$ 4,000	$ 20,000	$ 4,000	$ 24,000
Total		1			$ 20,000	$ 4,000	$ 24,000
Vault mounted 450 kVA, 1-ph	600	1	$ 12,000	$ 4,500	$ 12,000	$ 4,500	$ 16,500
Vault mounted 50 kVA, 3-ph	600/347	3	$ 5,000	$ 4,000	$ 15,000	$ 12,000	$ 27,000
Vault mounted 600kVA, 3-ph	600/347	1	$ 15,000	$ 5,000	$ 15,000	$ 5,000	$ 20,000
Vault mounted 2000kVA, 3-ph	600/347	1	$ 30,000	$ 7,500	$ 30,000	$ 7,500	$ 37,500
Total		6			$ 72,000	$ 29,000	$ 101,000
Total Investment Required over next 6 years					$ 601,500	$ 333,000	$ 934,500
Annual Investment Required					$ 100,250	$ 55,500	$ 155,750

Exhibit 5-6: Capital Investment Needs – Vault-mounted Transformers

5.7. Substations

Based on the results of condition assessment of the fixed assets installed in substations documented in Section 4 and to mitigate risk associated with various assets, the capital investment needs for the substations are summarized in Exhibit 5-7.

5.8. Overall Capital Investments into Asset Sustainment

Exhibit 5-8 provides overall capital investment estimates for asset sustainment required during the 5 year period covered by the study, including the cost of rebuilding of duct banks in the down core.

	2015		2016		2017		2018		2019	
	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab
Substations 13.8 kV Breakers	$175,000	$ 7,500	$ 175,000	$ 7,500						
Substations Power Transformers									$ 800,000	$ 50,000
Concrete pads and oil containment									$ 100,000	$ 50,000
44 kV Circuit Breakers					$ 440,000	$ 60,000	$ 440,000	$ 60,000	$ 330,000	$ 45,000
Total	$175,000	$ 7,500	$ 175,000	$ 7,500	$ 440,000	$ 60,000	$ 440,000	$ 60,000	$1,230,000	$ 145,000

Exhibit 5-7: Capital Investment Needs – Substations

	2015		2016		2017		2018		2019	
	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab	Mat	Lab
Substations	$ 175,000	$ 7,500	$ 175,000	$ 7,500	$ 440,000	$ 60,000	$ 440,000	$ 60,000	$1,230,000	$ 145,000
Underground Cables	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260	$ 159,559	$ 735,260
Overhead Lines	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600	$ 984,189	$ 865,600
Disconnect Switches and Cutouts	$ 156,667	$ 224,000	$ 156,667	$ 224,000						
Pad mounted Dist Transformers	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800	$ 140,833	$ 47,800
Pole mounte Dist Transformers	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250	$ 320,667	$ 176,250
Vault Mounted Dist Transformers	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500	$ 100,250	$ 55,500
Submersible Dist Transformers	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417	$ 2,750	$ 2,417
Downtown Core Underground Duct/Manhole/Vault system	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 75,000	$ 175,000	$ 175,000	$ 100,000	$ 100,000
Total Capital Investments Into Sustainement	$ 2,114,915	$ 2,189,327	$ 2,114,915	$ 2,189,327	$ 2,223,249	$ 2,017,827	$2,323,249	$ 2,117,827	$3,038,249	$ 2,127,827
Total Capital Investments Into Sustainement	$ 4,304,242		$ 4,304,242		$ 4,241,075		$ 4,441,075		$ 5,166,075	

Exhibit 5-8: Overall Capital Investment Needs – Asset Sustainment

5.9. *Fixed Asset Preventative Maintenance:*

We have reviewed the fixed asset preventative maintenance program currently in use at Oshawa PUCN and determined that it is generally in line with the best utility practices. No major changes are recommended in the preventative maintenance program, which is briefly described below:

All critical assets installed at substations are monitored on-line through SCADA system. Critical assets installed in substations are inspected monthly. Major maintenance on substation equipment is carried out on a 4-year cycle, but the scope of the maintenance is determined based on the asset needs by taking into account asset condition. It is recommended that the substation ground grid be inspected periodically, once in 10 to 15 years.

The underground vaults in the downtown core, supplying important commercial customers are inspected annually and maintenance is carried out on as required basis.

Overhead lines, underground pads and underground vaults outside of the downtown core are inspected on a 3-year cycle, to comply with Electrical Safety Authority's regulations.

Tree trimming is carried out on a 3-year cycle in the future. Infrared Scan of all the critical assets is carried out annually. 100% of the poles have been tested from 2004 to 2007. It is recommend that the pole testing be carried out once every 10 years, but only poles older than 30 years or those with previously identified risks be included in the inspections.

Appendix A – Condition Assessment of Equipment Vaults

Vault Number	local number	address/description	last inspected	vault constructed	transformer size	transformer yr	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	infra red readings pri and sec connections in degrees
sidewalk vault #1	2518	5 william st	2010	1982	3*250Kva	1982	4 way SF6	yes	vent/no fans	3	3	3	yes	small (3)	beams show minor rust	good 26-35
sidewalk vault #2	1193	4 bond st w	2010	1982	3*250Kva	1982	4 waySF6	yes	fans	2	2	2	yes	very small (2)	major beams rotten	good 31-44
sidewalk vault #3	1173	8 simcoe st n	2010	1982	3*333Kva	2004	4 way SF6	yes	fans	3	3	3	no	fine (4)	good	good 29-41
	1178&1182	44 Bond St W Bond Towers	2010	1974	3*250Kva & 3*333Kva	1973/1974	4 way SF6	no	natural	3	n/a	n/a	no	3	good	good
	1179	22 king st w	2010	1973	3*167Kva	1973		in building		3	3	n/a	no	3	3	good 32-40
sidewalk vault #5	1167	13 Athol St w	2010	1982	3*250Kva	1982	4 way SF6	yes	fans	3	3	3	no	3	3	good 35-41
sidewalk vault #6	1168	44 King St E regent	2010	1971	3*333Kva	1971	4 way SF6	yes	fans	3	3	3	no	very small(2)	minor water/salt damage beams in	good 35-48
	1594&1595	33 King St w Michael Star Building	2010	1981	2*1500/2000Kva	1981	S&C adulti-rupter Type SM-5	no	fans	3	2	3	no	4 large vault room	needs work on lighting	good
	1206	40 King St. W.	2010	1979	3*500kva	1979	two Single S&C switches	no	natural	3	n/a	n/a	no	3		
vault #7	3237	50 mary st	2010	1976	3*50Kva	1976	n/a	no	n/a	3	3	n/a	yes	small (2)	not a true vault open grated top	
	3244	70 King St. E.Genosha	2010	u/k	3*75Kva	1979	two Single S&C switches	no	n/a	3	3	n/a	no in building basement	3	3	
	3246	55 Athol St. E. Bell Vault	2010	2001	3*333Kva	2001	3 5way SF6 switches with programable protection settings	no	natural	4	4	n/a	no in building basement with exterior access	4	4	good
	3579	60 Bond St E Carriage Retirement Home	2010		3*100Kva	2000	1 5 way SF6 switch	no	natural	4	4	n/a	no in building basement with exterior access	4	4	good

Exhibit A-1 (EquipmentVaults – Condition Assessment)

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	4177	47 Simcoe St S Post Office	2010		3*167kVA	n/a	DRAIN	natural	4	4	n/a	no in building basement	4	4	good
	4178	2 Simcoe St S CIBC Sidewalk Vault	2010		3*250Kva	5 way S&C switch	no	natural	4	4	3	no	4	4	good
	5237	80 Athol St. E.Apartment/condo	2010	1987	3*167kVA	3 street light power centers and 3 way primary junction	no	natural	4	4	3	no	4	4	good
	10058	285 Taunton Rd. E Five Points Mall	2009	1974	3*333Kva	1 five way SF6 switch	no	natural	4	4	3	no	4	4	good
	12128	419 King St. W. OC Vault 3 -E side S of Zellers	2010		3*500Kva	Joslyn 6257 Four way SF6	drain	natural	4	n/a	n/a	no	4	4	good
	12132	419 King St. W. OC Vault 8 - The Bay	2010		3*333Kva	G&W five way SF6 switch	drain	natural	4	n/a	n/a	no	4	4	good
	12141/ 12142	419 King St. W. OC Vault 2 -E side S of Eatons	2010		two sets of 3*500Kva	G&W five way SF6 switch	drain	natural	5`	n/a	n/a	no	5	very large room	good
	12143/ 12144/ 12145	419 King St. W. OC Vault 1 - N End Tunnel	2010		three sets of 3*500Kva	G&W five way SF6 switch	drain	natural	5	n/a	n/a	no	5	very large room	good
	12150	419 King St. W. OC Vault 7 - Eside Zellers & The Bay	2010		3*333Kva	minrupter S&C switch (79)	drain	natural	5	n/a	n/a	no	3	room	good
vault #4	12153	17 King St E office	2010	1989	3*100Kva	G&W four way SF6 switch (89)	drain	natural	4	3	3	no	4	basement room	good
	13106	28 Albert St Apartment Building	2010	1994	3*100Kva	4 way SF6 vacpak	drain	natural	4	n/a	n/a	no	3	room	good
	13106	28 Albert St	2010	1994	3*100Kva	4 way SF6 vacpak	no	natural	4	4	n/a	no	4	basement room	good
	14126	419 King St. W. OC Vault 4 - Wside Chapters	2010												

Exhibit A-1 (EquipmentVaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	165	710 Raleigh Ave.	2010	1970	3*250Kva	n/a	no	open vents no fans	4	n/a	n/a	no	4	3	good
	417	11 Quebec st	2010	1970	3*100Kva	n/a	no	open vents no fans	4	n/a	n/a	no	4	3	good
	458	373 Simcoe St. S.	2010	u/k	3*25Kva	n/a	no	open vents no fans	4	n/a	n/a	no	4	3	good
	499	237-255 King St. W.Teddy's Plaza	2008	1965	3*75Kva	n/a	no	open vents no fans	3	n/a	n/a	no	4	3	good
	653	745 Stevenson Rd N	2009	1965	3*333Kva	n/a	no	open vents no fans	3	n/a	n/a	no	4	3	good
	995	230 Nipigon St.Apartment	2008	1985	3*50Kva	n/a	no	open vents no fans	3	n/a	n/a	no	3	3	good
	1105	77 Centre St. N.Police Station	2008	1971	3*167Kva	n/a	no	open vents no fans	3	n/a	n/a	no	3	3	good
	1106	44 William St W Faith Place	2008	1985	3*100Kva	n/a	no	open vents no fans	4	4	4	no	4	3	good
	1122	247 Simcoe St. N.Medical Center	2008	1982	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1148	363 Simcoe St. N.Apartment Building	2008	1984	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1159	124 Park Rd. N. Apartment Building	2010	1985	3*167Kva	n/a	no	fans	3	3	3	no	3	3	good
	1163	255 Simcoe St. N.Apartment Building	2008	1967	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1187	22 Athol St. E.Illusions	2008	1975	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1190	337 Simcoe St. N.Apartment	2008	1976	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1191	120 Elgin St. W.Apartment Building	2008	1976	3*100Kva	n/a	no	open vents no fans	4	4	4	no	3	3	good
	1195	60 Bond St W Durhan Towers	2008	1978	3*100Kva	2 single S&C fused disconnect style	no	open vents no fans	4	4	4	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	1196	15 Victoria St Old Bell Building	customer owned equipment		1000kva										
	1197	50 Centre St. S. City Hall	customer owned transformers		2*750Kva	2 single S&C fused switchgear 1968	no	open vents no fans	4	4	4	no	3	3	good
	1198	11 Simcoe N Old Bank of N.S.	customer owned		450kva										
	1204/1205	55 William St. E.McLaughlin Square	2008	1979	2 3 phase 1500kva	2 single S&C fused switchgear 1979	no	open vents no fans	4	3	3	no	3	3	good
	1270	321 Marland Ave. apartment building	2010	1973	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1274	300 Grenfell St.Apartment Building	2010	1974	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1275	291 Marland Ave.	2010	1973	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1276	310 Marland Ave.	2010	1974	1*75kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1278	322 King St. W. credit union	2010	1979	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1280	330 Gibb St.Apartment	2010	1969	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1281	400 Grenfell St.apartment	2010	1973	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1285	380 Gibb St. apartment	2010	1966	3*75Kva	n/a	no	open vents no fans	3	3	3	no	2	3	good
	1288	280-290 Marland Ave.	2010	1968	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1610	1011 Bloor St E Holiday Inn	2010	1970	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	1940	1300 King St. E. (East) east end Loblaws Kingsway Mall	2008	1984	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	2104	199 Hillcroft St Apartment Building	2008	1969	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	2191	97 Colborne St E Apartment Building	2008	1982	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	2209	172 King St. E.Sunray Plaza	2008	1981	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	2239	226 Bond St. E.Curling Club	2008	1973	1*150Kva/1* 100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	2251	122 Colborne St E Carriage Hill Apartment	2008	1975	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	2591	590 Galahad School	2008	1976	urd to 300Kva	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	good
	3206	357 Wilson Rd S URD Plaza	2010	1983	3*100Kva	n/a	no	open vents no fans	3	2	3	no	3	3	good
	3224	117 King St E Oshawa Clinic	2008	1970	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	3242	155 King St. E. / Athol Apartment	2008	1976	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4156	Midtown Mall vault#1	2008	1974	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4157	Midtown Mall vault#2	2008	1974	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4163	101 Bloor St. W.Apartment Building	2010	1972	100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4167	1300 King St. E. (West) Zellers	2008	1984	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4169	Midtown Mall Vault#3	2008	1974	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4171	454 Centre St S / Mill	2010	1984	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	4173	525 St. Lawrence St.Apartment Building	2010	1976	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4174	123 Bloor st W Apartment Building	2010	1977	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4175	57 simcoe St S Lord Simcoe Place	2008	1982	3*100Kva	SF6-vacpak 1982	no	open vents no fans							
	4180	115 Simcoe St S (Frank Building)	2008	1988	3*75kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4214	555 Simcoe St. S./Albert Zellers off Albert	2010	1984	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4328	346 Elgin Crt Apartment Building	2008	1985	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4330	100 William St. W. Apartment Building	2008	1968	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4332	110 Park Rd. N. Apartment Building	2010	1985	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4343	250 Taunton Rd. E.Plaza	2009	1985	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4348	47 Bond St. W. Bus Station	2008	1984	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4673	900 Wilson Rd N apartment building	2010	1987	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4741	300 Tauton Rd E apartment Building	2009	1986	3*333Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4868	850 King St. W Plaza	2010	1986	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	4896	73 Queen St.Art Gallery	2008	1986	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5132	1076 Cedar St.Plaza	2010	uk	3*50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5190	822 Glen St.Apartment Building	2010	1976	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5197	835 Oxford St.Apartment Building	2010	1976	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	5204	885 Oxford St.Apartment Building	2010	1976	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5209	275 Wentworth St. W.Apartment Building	2010	1969	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5213	549 Oxford St.Apartment Buiilding	2010	1971	50kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5252	840 Simcoe St. S.Apartment Building	2010	1969	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5291	280 Wentworth St. W.Apartment Building	2010	1971	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5297	1040 Cedar St.Apartment Building	2010	uk	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5312	888 Glen St.Apartment Building	2010	1972	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5313	900 Glen St.Apartment Building	2010	1972	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5325	922 Glen St.Apartment Building	2010	uk	3*167Kva	n/a	no	open vents no fans	2	2	2	2	3	3	good
	5326	936 Glen St.Apartment Building	2010	1973	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5383	777 Oxford St.Apartment Building	2010	1976	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5422	575 Wentworth St. W. G.M. Quality Control	2010	uk	3*500Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	5441	700 Wilson Rd N apartment Building	2008	1976	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7158	945 Simcoe St. N.Apartment Building	2009	uk	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7160	994 Simcoe St. N.Apartment Building	2009	1968	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7163	190 Nonquon Rd.Apartment Building	2009	1965	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7164	1140 Mary St. N.Apartment Building	2009	1966	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	7173	119 Nonquon Rd.Apartment Building	2009	1965	3*150Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7180	1221 Simcoe St. N.(West)Apartment Building	2008	uk	3*37.5Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7181	1221 Simcoe St. N.(East)Apartment Building	2008	uk	3*37.5Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7182	140 Nonquon Rd.Apartment Building	2008	1965	3*200Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7189	95 Taunton Rd. E.Apartment Building	2009	1966	3*75Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7190	191 Nonquon Rd.Apartment Building	2009	1966	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7237	1266 Pentland St.Apartment Building	2009	1969	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7238	1265 Pentland St.Apartment Building	2010	1969	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7248	155 Nonquon Rd.Apartment Building	2009	1969	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7252	111 Taunton Rd. E.(East)Apartment Building	2009	1969	3*150Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7253	111 Taunton Rd. E.(West)Apartment Building	2009	1969	3*150Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7262	141 Taunton Rd. E.Apartment Building	2009	1970	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7263	777 Terrace Dr.(East)Apartment Building	2009	uk	100kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7264	777 Terrace Dr.(West) Townhouse	2009	uk	100kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7265	777 Terrace Dr.(South) Townhouse	2009	uk	100kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	7281	177 Nonquon Rd. Apartment Building	2009	1971	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7283	500 Mayfair Ave.Apartment Building	2009	1972	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7284	666 Terrace Apartment Building	2008	1971	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7285	511 Canonberry Crt.Apartment Building	2008	1972	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7312	512 Canonberry Crt.(North)Apartment Building	2009	1973	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7313	516 Canonberry Crt. Apartment Building	2009	1973	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7314	512 Canonberry Crt.(North) Apartment Building	2009	1973	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7355	222 Nonquon Rd. Apartment Building	2009	1970	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7363	1320 Mary St. N. Apartment Building	2009	1974	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7374	555 Mayfair Ave. Apartment Building	2009	1975	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7377	97 Nonquon Rd. Apartment Building	2009	1975	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7446	110 Nonquon Rd. Apartment Building	2009	1976	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	7532	1371 Simcoe ST N Apartment Building	2009	uk	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	9102	385 Elgin Crt Apartment Building	2008	1985	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	10121	600 Grandview St S Plaza	2010	1989	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Vault Number	Local number	Address/description	last inspected	vault constructed	transformer size	switchgear	sump pump	ventalation	Condition of walls	Condition of roof	Condition of pavement	Is this location prone to flooding?	Size of vault for worker safety	vault structure	Infra Red readings pri and sec connections in degrees
	12156	73 John St. W. Seniors Building	2008	1989	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	12191	1 Mary St. N.Bond &Mary Garage	2008	1990	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	12250	600 King St. E. A&P Plaza	2008	1991	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	13110	675 King St. E. Medical Center	2008	1974	3*50Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	13125	666 King St. E. Apartment Building	2008	1976	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	13131	564 King St. E. Price Choppers	2008	1978	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	14118	139 Mary St. N. Apartment Building	2008	1992	3*167Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	14124	1252 Pentland St. Apartment Building	2009	1992	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	14125	1256 Pentland St. Apartment Building	2009	1992	3*100Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good
	14173	700 Stevenson Rd N PaulDwyer School	2009	1993	3*250Kva	n/a	no	open vents no fans	3	3	3	no	3	3	good

Exhibit A-1 (Equipment Vaults – Condition Assessment) Continued

Appendix B – Substation Equipment

SUBSTATION NAME	BREAKER NAME	Install Date	Age	SYSTEM VOLTAGE	Criteria	Rankings	Score	Weight Assigned	Maximum weighted Score	Total Score
MS #2	T1	1984	30	44kV	Age	C	3	8	24	
	T1			44kV	Breaker Maintenance	C	3	8	24	60
MS #2	T2	1984	30	44kV	Age	C	3	8	24	
	T2			44kV	Breaker Maintenance	C	3	8	24	60
MS #5	T1	1974	40	44kV	Age	D	2	8	16	
	T1			44kV	Breaker Maintenance	C	3	8	24	50
MS #5	T2	1981	33	44kV	Age	C	3	8	24	
	T2			44kV	Breaker Maintenance	C	3	8	24	60
MS #7	T1	1977	37	44kV	Age	D	2	8	16	
	T1			44kV	Breaker Maintenance	C	3	8	24	50
MS #7	T2	1968	46	44kV	Age	E	1	8	8	
	T2			44kV	Breaker Maintenance	C	3	8	24	40
MS #10	T1	1980	34	44kV	Age	C	3	8	24	
	T1			44kV	Breaker Maintenance	C	3	8	24	60
MS #10	T2	1973	41	44kV	Age	E	1	8	8	
	T2			44kV	Breaker Maintenance	C	3	8	24	40
MS #11	T1	1972	42	44kV	Age	E	1	8	8	
	T1			44kV	Breaker Maintenance	D	2	8	16	30
MS #11	T2	1968	46	44kV	Age	E	1	8	8	
	T2			44kV	Breaker Maintenance	D	2	8	16	30
MS #13	T1	1967	47	44kV	Age	E	1	8	8	
	T1			44kV	Breaker Maintenance	C	3	8	24	40
MS #13	T2	1978	36	44kV	Age	D	2	8	16	
	T2			44kV	Breaker Maintenance	C	3	8	24	50
MS #14	T1	1978	36	44kV	Age	D	2	8	16	
	T1			44kV	Breaker Maintenance	D	2	8	16	40
MS #14	T2	1971	43	44kV	Age	E	1	8	8	
	T2			44kV	Breaker Maintenance	D	2	8	16	30
MS #15	T1	1977	37	44kV	Age	D	2	8	16	
	T1			44kV	Breaker Maintenance	C	3	8	24	50
MS #15	T2	1984	30	44kV	Age	C	3	8	24	
	T2			44kV	Breaker Maintenance	C	3	8	24	60

Exhibit B-1: 44 kV Breaker Condition Assessment

Designation	In Service Year	MVA Rating	Peak load MVA	% loading	HI Age Score					
					Criteria	**Rankings**	**Score**	**Weight Assigned**	**Maximum weighted Score**	**Total Score**
MS 2-T1	2012	41.7	18	43.17	Age of transformer	A	5	6	30	**100**
					Peak loading	A	5	4	20	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 2-T2	2012	41.7	21	50.36	Age of transformer	A	5	6	30	**96**
					Peak loading	B	4	4	16	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 5-T1	1984	33	27	81.82	Age of transformer	C	3	6	18	**44**
					Peak loading	C	3	4	12	
					Visual inspection	C	3	2	6	
					Testing	E	1	8	8	
MS 5-T2	1983	33	25	75.76	Age of transformer	D	2	6	12	**64**
					Peak loading	C	3	4	12	
					Visual inspection	B	4	2	8	
					Testing	B	4	8	32	
MS 7-T1	1981	33	24	72.73	Age of transformer	D	2	6	12	**66**
					Peak loading	B	4	4	16	
					Visual inspection	C	3	2	6	
					Testing	B	4	8	32	
MS 7-T2	1980	33	29	87.88	Age of transformer	D	2	6	12	**62**
					Peak loading	C	3	4	12	
					Visual inspection	C	3	2	6	
					Testing	B	4	8	32	

Exhibit B-2: Power Transformers

Designation	In Service Year	MVA Rating	Peak load MVA	% loading	HI Age Score					
					Criteria	Rankings	Score	Weight Assigned	Maximum weighted Score	Total Score
MS 10-T1	2004	41.7	19	45.56	Age of transformer	A	5	6	30	**82**
					Peak loading	A	5	4	20	
					Visual inspection	B	4	2	8	
					Testing	C	3	8	24	
MS 10-T2	1988	33.3	38	114.11	Age of transformer	C	3	6	18	**66**
					Peak loading	D	2	4	8	
					Visual inspection	B	4	2	8	
					Testing	B	4	8	32	
MS 11-T1	2011	41.7	14	33.57	Age of transformer	A	5	6	30	**100**
					Peak loading	A	5	4	20	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 11-T2	2011	41.7	15	35.97	Age of transformer	A	5	6	30	**100**
					Peak loading	A	5	4	20	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 13-T1	2011	41.7	12	28.78	Age of transformer	A	5	6	30	**100**
					Peak loading	A	5	4	20	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 13-T2	2012	41.7	21	50.36	Age of transformer	A	5	6	30	**86**
					Peak loading	B	4	4	16	
					Visual inspection	B	4	2	8	
					Testing	B	4	8	32	
MS 14-T1	1979	33.3	36	108.11	Age of transformer	D	2	6	12	**58**
					Peak loading	D	2	4	8	
					Visual inspection	C	3	2	6	
					Testing	B	4	8	32	
MS 14-T2	1978	33	30	90.91	Age of transformer	D	2	6	12	**62**
					Peak loading	C	3	4	12	
					Visual inspection	C	3	2	6	
					Testing	B	4	8	32	
MS 15-T1	2012	41.7	19	45.56	Age of transformer	A	5	6	30	**100**
					Peak loading	A	5	4	20	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	
MS 15-T2	2012	41.7	33	79.14	Age of transformer	A	5	6	30	**92**
					Peak loading	C	3	4	12	
					Visual inspection	A	5	2	10	
					Testing	A	5	8	40	

Exhibit B-2: Power Transformers (Continued)

Breaker ID	Year of maunfactur	Criteria	Rankings	Score	Weight Assigned	Maximum weighted Score	Total Score
MS 2-T1	1984	Age	C	3	8	24	
		Breaker Maintenance	C	3	8	24	60
MS 2-T2	1991	Age	C	3	8	24	
		Breaker Maintenance	C	3	8	24	60
MS 2-Tie	1984	Age	C	3	8	24	
		Breaker Maintenance	B	4	8	32	70
MS 2-F1	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 2-F2	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 2-F3	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 2-F4	1991	Age	C	3	8	24	
		Breaker Maintenance	C	3	8	24	60
MS 2-F5	1991	Age	C	3	8	24	
		Breaker Maintenance	C	3	8	24	60
MS 2-F6	1991	Age	C	3	8	24	
		Breaker Maintenance	C	3	8	24	60
MS 5-T1	1975	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 5-T2	1981	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 5-Tie	1975	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 5-F1	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 5-F2	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 5-F3	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 5-F4	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 5-F5	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 5-F6	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-T1	1977	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 7-T2	1968	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 7-Tie	1968	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 7-F1	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-F2	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-F3	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-F4	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-F5	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 7-F6	2009	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90

Exhibit B-3: 13.8 kV Circuit Breakers

MS 10-T1	1980	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 10-T2	1973	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 10-Tie	1973	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 10-F1	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 10-F2	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 10-F3	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 10-F4	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 10-F5	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 10-F6	2012	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-T1	1975	Age	D	2	8	16	
		Breaker Maintenance	B	4	8	32	60
MS 11-T2	1988	Age	C	3	8	24	
		Breaker Maintenance	B	4	8	32	70
MS 11-Tie	1975	Age	D	2	8	16	
		Breaker Maintenance	B	4	8	32	60
MS 11-F1	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-F2	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-F3	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-F4	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-F5	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 11-F6	2011	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90

Exhibit B-3: 13.8 kV Circuit Breakers (Continued)

MS 13-T1	1967	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 13-T2	1978	Age	D	2	8	16	
		Breaker Maintenance	C	3	8	24	50
MS 13-Tie	1967	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 13-F1	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 13-F2	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 13-F3	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 13-F4	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 13-F5	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 13-F6	2008	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-T1	2007	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-T2		Age		0	8	0	
		Breaker Maintenance	E	1	8	8	20
MS 14-Tie		Age		0	8	0	
		Breaker Maintenance	E	1	8	8	20
MS 14-F1	2007	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-F2	2010	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-F3	2010	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-F4	2010	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-F5	2010	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 14-F6	2010	Age	A	5	8	40	
		Breaker Maintenance	B	4	8	32	90
MS 15-T1	1983	Age	D	2	8	16	
		Breaker Maintenance	B	4	8	32	60
MS 15-T2	1983	Age	D	2	8	16	
		Breaker Maintenance	B	4	8	32	60
MS 15-Tie	1968	Age	E	1	8	8	
		Breaker Maintenance	C	3	8	24	40
MS 15-F1	2009	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80
MS 15-F2	2009	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80
MS 15-F3	2009	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80
MS 15-F4	2009	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80
MS 15-F5	2008	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80
MS 15-F6	2009	Age	A	5	8	40	
		Breaker Maintenance	C	3	8	24	80

Exhibit B-3: 13.8 kV Circuit Breakers (Continued)

Station #	cpu board	analog boards	status boards	control boards	Condition of seals to prevent rodent access	Condition of seals to prevent moisture ingress	Condition of door hinges	Condition of seals at cable entrance	Discolration of nameplates	Peeling of cable labels	Health Index
MS #2	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #5	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #7	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #10	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #11	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #13	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #14	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52
MS #15	scout rtu 2006	1991	1991	1991	4	4	5	3	3	3	52

Exhibit B-4: SCADA RTU

Station #	Condition of Charger	charger install date	Condition of Battery	battery date (age)	battery age	charger age	Health Index
MS #2	4	2005	4	2007	6	8	80
MS #5	3	2004	3	2004	9	9	64
MS #7	5	2013	3	2003	10	0	76
MS #10	5	2013	4	2005	8	0	86
MS #11	4	2003	5	2010	3	10	90
MS #13	4	2008	4	2007	6	5	84
MS #14	5	2011	5	2013	0	2	100
MS #15	4	2009	5	2013	0	4	94

Exhibit B-5: Control Battery and Charger

Station #	Security Cameras in service	Condition of walls	Condition of roof	Security and access	Height of Security fence indicate in ft.	Condition of anti climbing barbed wire?	Clearance at the bottom of fence?	Condition of fence posts	Condition of warning signs	Safety Signage	Condition Rating	Condition Rating
MS #2	y	3	3	3	6	3	fine	3	4	4	3.4	Good
MS #5	n	3	3	3	6	3	fine	3	4	4	3.4	Good
MS #7	n	3	3	3	6/10	3	fine	3	4	4	3.4	Good
MS #10	n	5	3	4	n/a	n/a	n/a		4	4	4	Very Good
MS #11	y	3	3	3	6	3	fine	3	4	4	3.4	Good
MS #13	y	3	3	3	6	3	fine	3	4	4	3.4	Good
MS #14	y	3	2	3	6/10	2	fine	3	4	4	3.2	Fair
MS #15	y	5	3	4	n/a	n/a	n/a		4	4	4	Very Good

Exhibit B-6: Substation Building and Yard

Oshawa Power & Utilities

Smart Grid Roadmap and Financial Analysis

April 17, 2014

April 17, 2014

Building Smart Utility Solutions

Executive Summary

Electric utilities have historically extracted as much value and efficiency as possible with manual controls. Today, however, we see a major shift in the thinking within the electric utility industry as it approaches the issue of building the electric infrastructure to ensure reliable and cost effective electric service given a set of challenges all occurring at the same time:

- *Aging Workforce* – A large percentage of skilled labor within the electric utility industry is expected to retire within the next five years, placing stresses on electric utilities to effectively manage systems with a large degree of manual intervention required
- *Aging Infrastructure* – Industry estimates and analysis suggest that losses to the economy due to outages, quality disturbances and other events could reach $20 billion annually in the Canadian economy
- *Financial Constraints* – Challenging financial times are calling into question how electric utilities can continue to access the capital needed to keep pace with projected needs to support grid reliability given the constraints of today's legacy electric grid
- *Environmental Concerns* – Under pressure from environmental groups and foreign governments, regulators are increasingly focusing on emissions regulations – resulting in increasing challenges for electricity distributors
- *Rising Fuel Costs* – Increasing fuel costs and capacity costs from rising coal and natural gas prices at the same time as projected increases in demand for generated power threatens to result in a tide of rising electric bills
- *Integration with New Technologies* – While the presence of evolving technologies offer opportunities to explore new approaches to effectively deliver electricity to consumers, electric utilities are often hamstrung by the roadblocks presented by operating grids that are in many ways not designed to integrate with new technical approaches

This set of issues – all occurring at the same time – presents a form of "perfect storm" that challenges the electric utility industry to identify the optimal approach for delivering cost effective and reliable electricity to customers in the 21st century. The "Smart Grid" – a way of adding intelligence and new protocols to the electric grid – is seen by many as the way to attack the challenges within the industry. While the specific components of any given smart grid can vary based on the unique needs of a given area or infrastructure, there are some common hallmarks of smart grid deployment:

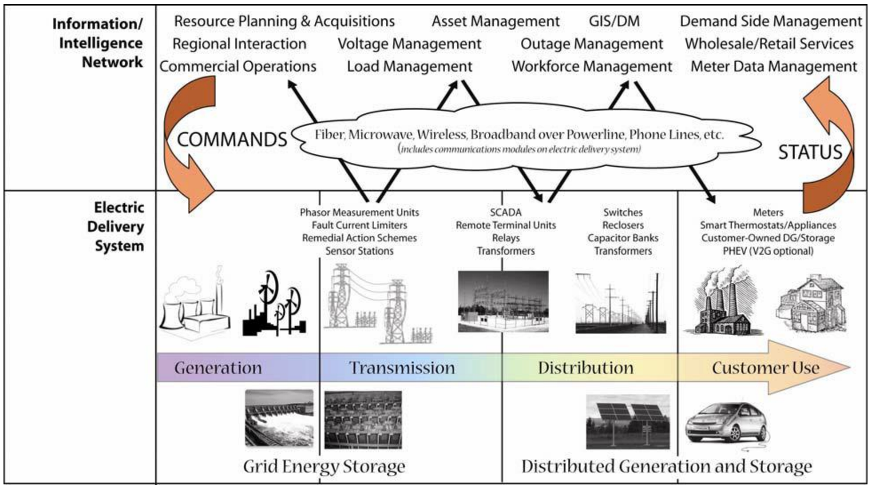
- An increase in digital controls across the grid rather than a continued emphasis on
- electromechanical and/or analog systems
- Robust two-way communications across the grid that allows the electric operator to see and respond to events on the line
- Systems that allow the electric utility to work with distributed generation and energy storage rather than conventional central generation alone
- Systems that allow for system operators to interact with the entire electric network rather than isolated components
- Increasing numbers of monitors and sensors throughout the electric grid

- Increasing system capabilities that provide for full monitoring and an elimination of the large number of “blind” spots throughout the network
- Restoration systems that are based on real-time information that direct utility workforce to the problem at hand, rather than relying on purely manual restoration methods
- Systems that provide for adaptive protection and system islanding to avoid the tendencies toward system failures and blackouts
- Systems that remotely check equipment out on the grid and eliminate the dependence on manual inspections
- The establishment of automated decision support systems and predictive reliability
- More pervasive control systems that provide system operators with greater control over power flows
- Full price information being transmitted to customers
- Greater degree of customer choice in the consumption of electricity

Utilities have been looking at opportunities within the smart grid arena for some time. With the confluence of events and trends occurring at this time, we see an increasing number of utilities poised to begin serious investigation of the opportunity at hand. However, in order to pursue smart grid investment, each of the key stakeholders involved – consumers, the electric utility, and society at large – must see that the effort offers value.

In short, we are witnessing a revolution in the way electric power is transmitted and distributed. It is a revolution characterized by the convergence of information technologies and electricity delivery technologies. Utility operating environments are changing rapidly, reflecting the impact of a number of key environmental and economic trends. To continue to serve the public well, and provide for future economic prosperity, utilities must adapt. They must redeploy resources – human, financial, and technical – in ways that continue to provide reliable, affordable service in a world that is becoming increasingly carbon-constrained. This is the context within which we should consider smart grids: they will be useful, and will constitute good investments; to the extent they help utilities address strategic trends and issues.

The key behind providing the necessary intelligence across the grid in the 21st century involves the ability to communicate seamlessly between the electric delivery system that is comprised of all the physical components that produce, distribute and use electricity and the information/intelligence system that is comprised of the data generated by the sensors and controls, the communications architecture used to communicate the data, and the planning and management processes (and possibly, the software systems) that use the data:



Given the developments within the industry, UtiliWorks Consulting (UtiliWorks or UWC) was contracted to provide Professional Services in regards to the Smart Grid Roadmap and Financial Analysis for Oshawa Power and Utilities (Oshawa).

UtiliWorks facilitated an onsite working session with Oshawa to derive the underlying business goals and objectives for this project. This information was compiled via onsite workshops with the respective functional teams and via a variety of detailed data requests. The data was then reviewed, and analyzed in order to establish the Utility's baseline upon which to develop projected costs and benefits. The outcome of this session along with review and analysis of information provided by Oshawa was the development of a list of goals and objectives, directly linked to Oshawa's interest in adopting system automation and program enhancement programs that offered demonstrable value to the community it serves.

UtiliWorks recommendations herein, support Ontario's Long Tem Energy Plan's five principles to balance cost-effectiveness, reliability, clean energy, community engagement and an emphasis on conservation and demand management before building new generation. The four main program areas identified by UtiliWorks for further development were categorized as:

- Metering
- Customer Service
- Distribution Operations
- Distributed Resources

The aim of this report is to assist Oshawa in identifying and qualifying the most relevant and beneficial aspects of Smart Grid for their upcoming rate case. The work represented in this report does not constitute a detailed design effort, nor does it layout a detailed, customized project plan. However, those will be needed at a later phase to bring more definition and clarity to deploy the recommended Smart Grid projects.

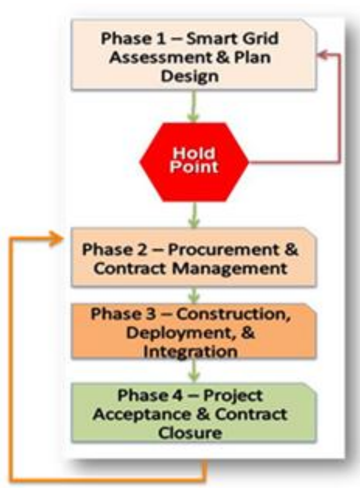
As part of this project, UtiliWorks conducted research and analysis into 23 different programs to identify those that offered to deliver significant positive value to Oshawa's customers and align with stated goals put forth by the Ontario Long Term Energy Plan. Of these 23 programs, we identified 13 that were deemed to be suitable for Oshawa's system and are recommended for further development. Of the 13 recommended programs, six (remote connect/disconnect, enhanced IVR, outage management, automated switching, demand management, and load control) have been initiated by Oshawa PUC and our recommendation is to continue to advance these programs. Seven others (prepaid metering, AMI process redesign, AMI extension, billing system redesign, SCADA upgrade, voltage monitoring, and transmission management) are not currently being pursued and UtiliWorks recommends initiating activities in these program areas. The net capital cost to enhance the existing programs and pursue the new programs is estimated at $12.22 million over a ten-year period.

The results of the recommended program offer the potential to generate significant benefits to Oshawa and the customers it serves. Some of the key findings of our analysis include:

- Reduction in system peak by between 2-4% by 2024
- Potential reduction in overall system usage by 0.2%
- Elimination of approximately one million minutes of customer outage annually
- Estimated reduction in CO_2 emissions by over 200 metric tons over a ten-year period
- Potential to reduce emissions of other greenhouse gases
- Potential job creation benefits

If Oshawa elects to proceed with this project, UWC recommends that, where possible, the goals are quantified and baselined so that Oshawa PUC can measure progress and verify that these goals are, in fact, achieved. UWC will assist with the identification and development of relevant Key Performance Indicators (KPIs) that are specific to Oshawa and to each specific project if Oshawa elects to proceed.

The figure below illustrates our standard phase progression methodology. We recommend deploying one project at a time with a narrower scope in the beginning rather than all projects at once. With this approach it is possible to get the project fundamentals working and assimilated into the utility organization before moving to the next Smart Metering project. The phase progression is repeated until all projects are installed within the Oshawa system.



Ontario's engagement with UtiliWorks is further evidence that the utility is dedicated to investments to modernize Ontario's electric grid and provide a "clean and reliable…foundation for future growth and prosperity."[1]

[1] Ontario Long Term Energy Plan 2013.

Background on UtiliWorks

UtiliWorks Consulting, LLC (est. 2006) offers professional services to assist clients in the evaluation, design, procurement, and implementation of Advanced Metering Infrastructure (AMI) and Smart Metering/Smart Grid programs. Our processes, people, and analysis tools lower project risks and ensure benefit capture.

Our team provides objective consultation by remaining completely vendor neutral. We do not associate our recommendations with any particular technology; rather we focus our efforts on developing a successful AMI or Smart Grid Program, applying the technology or a combination of technologies that fit your environment.

UtiliWorks identifies project business drivers and critical success factors for AMI implementation. We also identify associated business process changes that must occur in order to maximize the benefits of an AMI implementation. In order to identify Utility improvement potential, UtiliWorks has developed a web-based technology assessment and analysis tool, UtiliWorks Insight™. This helps the client understand and evaluate specific performance gaps and improvement opportunities.

It is our goal is to help our clients be more successful by providing leadership, industry experience and proven Smart Meter/AMI implementation methodologies. Currently we employ Engineers, Subject Matter Experts, and Consultants across the organization. The UtiliWorks Team consists of senior level project managers, engineers, communication system engineers and professionals with extensive experience in AMR/AMI, Smart Grid, Smart Metering, Process Controls, SCADA, and Utility Technology projects. Our associates have on average more than 20 years related industry experience. Our staff includes 10 Full time employees and 10 regular subcontract SMEs.

As a professional services firm, UtiliWorks team assists clients in the evaluation, design, procurement, and implementation of Advanced Metering Infrastructure (AMI), Smart Grid, and related Technology Solutions. Our subject matter expertise includes:

- AMI Hardware and Software
- Backhaul Design
- Business Process Engineering
- Business Analysis
- C&I Demand Charge Management
- Customer Communication
- Cyber Security Implementation
- Data Analytics
- Distribution Automation
- MDMS Implementation
- Strategy and Business Case
- Kiosk Implementation
- Prepay Implementation
- Project Coordinator
- Project Management
- SCADA Systems
- Social Media
- Systems Engineering
- Contract Administrator
- Meter Data Mapping
- Meter Specification/configuration
- Financial Modeling

UtiliWorks is uniquely positioned to assist clients in developing an accurate picture of costs, benefits, opportunities, and risk before making a significant AMI and Smart Grid technology investment. This is accomplished through The UtiliWorks Advantage™, which is a process model focusing on network delivery of utility data and business work flow changes that drive performance throughout the client organization. By performing this evaluation in conjunction with client personnel, we determine which technologies are best suited for the target application and service area.

Contact Information	2351 Energy Drive, Suite 1200 Baton Rouge, Louisiana 70808 www.utiliworks.com P (225) 766-4188 F (225) 612-6404
Business Focus	Smart Grid Design, Assessment, and Implementation Meter Data Management and related business and work process management
Company Information	Limited Liability Company FEIN: 20-5167904 DUNS: 825164713
Services	Professional Services Firm Business and Technology Consulting Turnkey Smart Metering Solution Development No vendor affiliations
Location	Corporate Headquarters in Baton Rouge, Louisiana Associates Nationwide (AL, CO, FL, LA, NC, NM, NY, PA, SC, TN)

Project Methodology

In order to identify the optimal vision and ultimate path for Oshawa PUC, UtiliWorks developed an approach to account for the unique characteristics of the Oshawa network, its customers, and the community it serves. In order to properly address the key issues at hand, a number of choices were made with respect to our chosen approach:

- *Oshawa-Centric* – The target of this study was to develop a plan that was viable from the perspective of Oshawa and its key stakeholders – the customers and community it serves. At each point in the study, UtiliWorks endeavored to identify specific elements of the Oshawa plan to evaluate how it would provide benefits given the unique characteristics of the Oshawa's network and operations.
- *Data Driven* – Rather than evaluate the potential for the Oshawa vision from a purely qualitative perspective, UtiliWorks developed a detailed modeling approach to evaluate the potential value proposition through the lens of fact-based analysis.
- *Aligned with Industry Norms* – UtiliWorks wanted to make sure that the vision, while being focused on Oshawa's unique characteristics, also aligned with overall industry norms and supported the direction provided by the Ontario Long Term Energy Plan.

In order to account for these issues, UtiliWorks developed a specific methodology for the study, detailed in a five-step process:

Step 1 – Industry Data Collection: To start, we conducted initial interviews with key staff members and process owners at Oshawa PUC to understand key processes, work functions, and output levels. In doing so, we were able to get a basic understanding of the tasks at hand and to understand the organizational structure and nature of system operation. Following up on initial discussions, we gathered data through a data request process and further interviews with key internal subject matter experts.

Step 2 – Industry Research: Give our stated goal to align the Oshawa vision with key industry norms and the Ontario Long Term Energy Plan, UtiliWorks worked to gather data related to the state of smart grid activity throughout the utility industry with an eye toward identifying applications for Oshawa PUC. We identified qualitative information in the form of best practices and industry trends and quantitative data in the form of cost and benefit details in order to build a model for Oshawa.

Step 3 – Benefit Analysis: UtiliWorks developed a detailed operational model to identify the potential benefits that would stem from the adoption of a variety of system automation programs. UtiliWorks then used the model, coupled with the internal data gathered from Oshawa (step 1) and the industry data collected (step 2) to develop a view into the potential benefits that could be captured, ranging from energy savings to peak reduction to outage minutes avoided.

Step 4 – Cost Analysis: In addition to modeling the benefits, we also considered the operating and capital costs associated with each program. In order to arrive at a total budget for the proposed set of programs under consideration, we gathered data from industry sources to identify the projected financial requirements associated. Under consideration were the costs for field devices and supporting systems. In each case, data was used from actual deployments that have occurred in similar deployments.

Step 5 – Validation: After conducting the analysis, we reviewed the results with the Oshawa subject matter experts to validate our conclusions and identify and potential areas requiring refinement in our modeling approach. Additional secondary research was also conducted to validate findings.

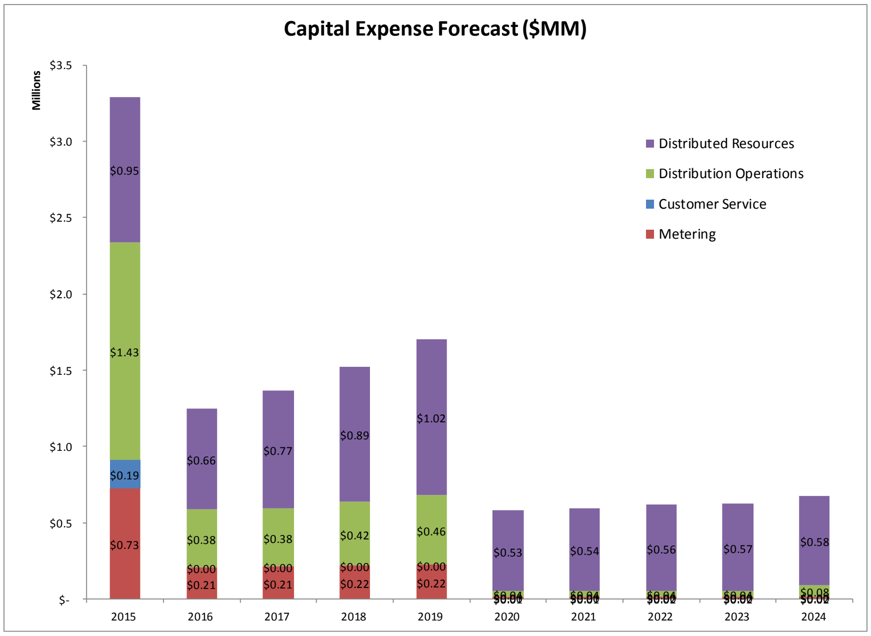
Findings

UtiliWorks engaged in detailed research and analysis into 23 different programs. The results of this effort are highlighted in the table below:

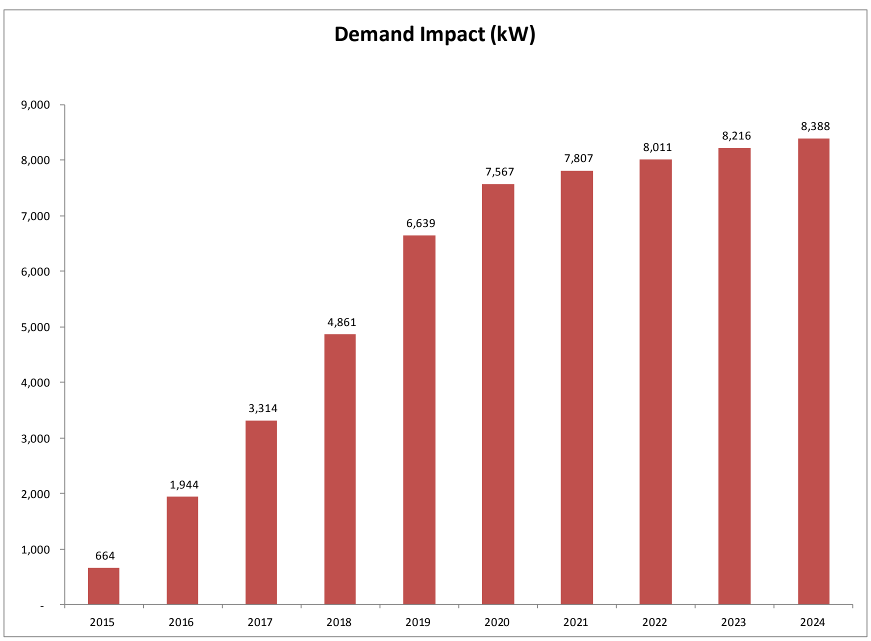
Program	Description	Investigated	Suitable for Oshawa	Proposed New Program	Already in Progress
Metering					
Prepaid Metering	Enabling prepaid metering to support customer control of accounts	X	X	X	
AMI Process Redesign	Enhancing system to create more efficient meter-to-bill process	X	X	X	
AMI Extension	Extending AMI reach to include all customers, including high use customers	X	X	X	
Remote Connect/Disconnect	Equipping meters with connect/disconnect collars to reduce labor costs	X	X		X
Customer Service					
Billing System Redesign	Integrating systems to reduce cost of back office operations	X	X	X	
Enhanced IVR	Extending the capabilities of Oshawa's IVR system to provide better customer service	X	X		X
Planned Outage Notification	Provide automated system that would notify customers in advance of a planned outage	X			
Payment Reminder System	Build a system that would provide billing reminders via text, e-mail, or automated phone call	X			
Web Start/Stop Service	Deploy automated system that would allow customers to self-provision service requests	X			
Distribution Operations					
SCADA Upgrade	Provide additional automation for Supervisory Control and Data Acquisition system	X	X	X	
Voltage Monitoring	Monitoring voltage and end of feeders to improve quality of service	X	X	X	
Outage Management	Developing a dynamic system to support outage notification and restoration efforts	X	X		X
Automated Switching	Installing automated switches in underground vaults to improve worker safety	X	X		X
Substation Monitoring	Deploying sensing equipment and video surveillance at substations to monitor equipment condition and theft/vandalism	X			X
Feeder Automation	Deploying IEDs and automated controllers, switch gears, RTUs, and capacitors to provide additional control over the network	X			X
Enhanced Communications Networks	Extending reach of field communications with fiber, wireless, and power line communications	X			X
Feeder Gateway Temperature Monitoring	Monitoring feeder gateway temperature to avoid outages and reduce need for system upgrades	X			
Phase and Load Balancing	Installing devices to balance the load across feeders and phases to improve grid efficiency	X			
Synchrophasors	Deploy phasor measurement units to provide a real-time measurement of electrical quantities across the power system	X			
Distributed Resources					
Transmission Management	Deploying system intelligence to enable more efficient management of wholesale power purchases	X	X	X	
Demand Management	Developing an energy demand management plan that combines demand response, energy storage, and distributed generation	X	X		X
Load Control	Installing load control devices to reduce system peak	X	X		X
Bulk Storage	Using energy storage to reduce system peak and generation requirements	X			

This proposed program features the following costs and benefits:

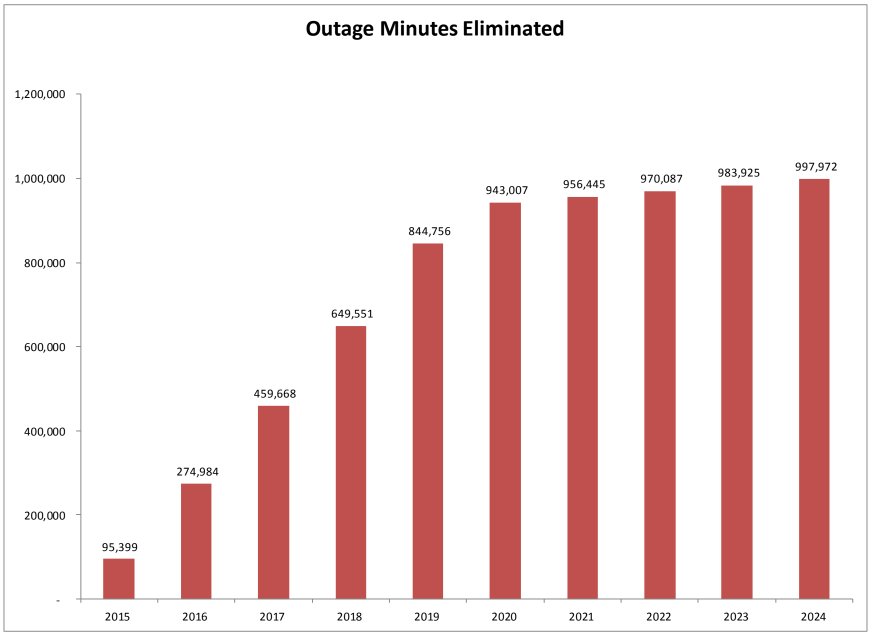
- The proposed cost for all equipment and supporting systems is calculated to be $12.22 million over a ten-year period (numerical breakdown provided in Appendix 2):



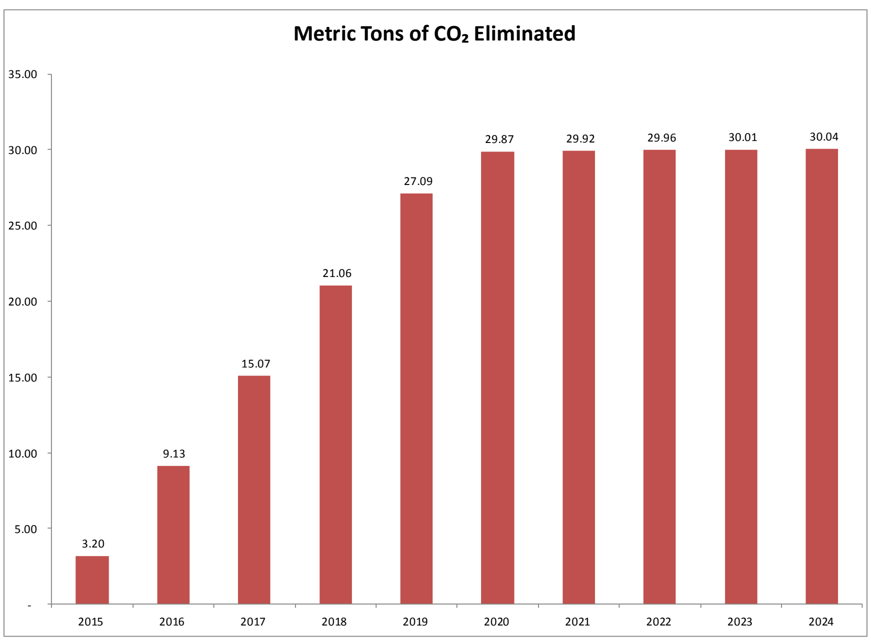
- The program is forecasted to reduce system peak requirements by 2-4% by the end of 2024:



- Outage minutes suffered by customers is projected to approach 1 million minutes annually by the end of the 10th year of system operation:



- The system is calculated to have the potential of removing over 200 metric tons of CO_2 emissions over a ten-year period:



Metering

For many utilities, the first, and largest, benefit group involves the advanced metering components of the smart grid. As Oshawa has already deployed an Advanced Metering Infrastructure (AMI) system, we are recommending the following add-on programs and functionality:

- Prepaid Metering – enabling customers to control their accounts through prepaid rather than postpaid accounts
- AMI Process Redesign – enhancing system to create more efficient metering and customer billing process
- AMI Extension – Extending AMI reach to include all customers, including high use customers
- Connect/Disconnect – providing the necessary field infrastructure to support the prepaid metering program

Prepaid Metering

Overview: Prepaid electricity systems afford many benefits to both the utility and to customers. Various deployment scenarios, including payment partners, kiosks, online and IVR exist to facilitate customer payments and ease walk-in volume. This system will automatically manage accounts based on their account balances. Users have a variety of options to manage notifications and monitor customer usage.

Perhaps contrary to popular instinct that such programs might be viewed as stigmatic or discriminatory, prepayment systems are welcomed by economically disadvantaged users due to the control and lack of encumbrance relative to being on a post-pay plan. This feature is typically rated very highly by customers of utilities that have implemented these programs.

Due to heavy dependence on AMI, MDMS, and CIS integration, those projects should be considered predecessor projects to this feature.

Benefits for Oshawa: Offering prepaid services to can facilitate multiple benefits to both parties involved – the customer and the utility. Specific benefits that can be realized by the Oshawa include:

- Reduce truck rolls
- Increase cash flow
- Reduce printing costs including:
    - Paper and Envelopes
    - Postage
    - Reminder notices
    - Disconnect notices
- Reduce overhead costs associated with customer service and collections
- Reduce write-offs
- Lower finance risk
- Increase Customer satisfaction

Specific benefits that can be realized by Oshawa's customers include:

- Elimination of high customer deposits
- Allows the customer to adhere to a predictable budget for utility payments
- The ability to monitor usage, payment, and balance information with web and smart phone applications
- Easy monitoring of consumption helps drive conservation and usage reduction

Industry Trends: Prepaid implementations at utilities are much more prevalent today. Most consumers are aware of the approach and may even be taking advantage of the functionality with other services such as prepaid cell phones. Utilities that have deployed AMI and remote disconnect meters are increasing the value of, and reducing the payback time on, their capital investment by offering prepaid service to their customers. Please see below for a sample list of utilities that have implemented prepayment solutions:

- City of Ruston, LA
- Salt River Project, AZ
- Energy United
- Progress Energy, Carolinas
- Woodruff Electric Cooperative
- Rappahannock Electric Cooperative
- Kansas City Board of Public Utilities (KCKBPU)
- Bryan Texas Utilities (BTU)
- City of Ocala Utility Service

AMI Process Redesign

Overview: As compelling as advanced metering programs may be, all of it is useless without significant upgrades to internal business processes. Existing workflows will disappear or be transformed dramatically by automation and new data. New workflows will need to be developed to move the utility to a more pro-active stance toward metering and system monitoring and away from the technology-imposed reactive methods previously employed. Utilities should be prepared to dedicate subject matter experts to identify, upgrade, and develop new business processes that fully utilize the new capabilities of the grid.

Benefits for Oshawa: Oshawa has already invested in a state-of-the-art advanced metering program for their residential and small commercial customers. However, given the need to support other customer-facing efforts, usability of the data becomes tantamount. A partial list of subject matter areas significantly impacted by new technology deployment includes:

- Meter to Bill
- Dispatch

- Asset Management
- Distribution Engineering
- Outage Management
- Customer Service

Advanced utility technology is highly integrated and especially sensitive to variances in the quality of data input; requiring adopters to practice strong discipline with regard to data integrity and maintenance processes. Due to the potential for disruption of business processes by technology, business process engineering should commence in the design phase of the project and continue through project completion following a continuous improvement philosophy.

Industry Trends: Now that AMI has become fairly prevalent within the utility industry, more and more utilities have become more actively focused on ensuring that systems exist to support the full usability of the data at hand. AMI is not just about finding a more cost effective way to bill customers; it involves integrating systems to provide greater information to utilities so they can serve customers better. A small sample of utilities that have engaged in this endeavor includes:

- City of Orangeburg, SC
- Pacific Gas & Electric
- Duke Energy
- CenterPoint Energy
- Arizona Public Service
- Salt River Project
- Hydro One

AMI Extension

Overview: Electric utilities come in various shapes and sizes but they all strive for essentially the same end result. They seek to deliver energy to their customers in an efficient, safe manner while safeguarding the utility's revenue stream, minimizing expenses, maintaining customer satisfaction, and protecting the supply of electricity. The rapid advancement of AMI has demonstrated the dedication to these goals. Electric utilities are concerned with future demands on their systems, aging infrastructure, and potential supply limitations. While not all network systems provide similar features and functions, utilities have invested in and deployed advanced metering infrastructure (AMI) systems designed to measure, collect, and analyze usage, as well as interact with other advanced devices to achieve total system monitoring. Many of these utilities have initially embarked on partial deployments in order to achieve a number of core benefits while reducing the overall expense of a full system deployment. However, there are some benefits – in particular those that call for full data access in order to enable system operators to view the entire grid’s operation to ensure system reliability – that do not scale proportionally and require a full deployment in order to capture the benefit of the AMI system.

Benefits for Oshawa: Oshawa has already deployed AMI meters to all of its residential and small commercial accounts. Accounts that feature larger commercial users in excess of 25 kW of demand do not currently feature an AMI meter and require manual intervention for both billing and customer support. Deploying an additional 745 meters to these customers would enable Oshawa to realize the full benefits and reduce the need for manual intervention.

Industry Trends: There exists a wide variety of utilities that have deployed partial AMI systems and have subsequently followed up with complete deployments in order to capture full system benefit. A sample list of these utilities includes:

- Southern California Edison
- Oncor
- CenterPoint Energy
- City of Burbank, CA
- Silicon Valley Power

Connect/Disconnect

Overview: Remote connect/disconnect capabilities are enabled by retrofitting existing meters with a collar or by choosing a remote disconnect capable meter for selected deployments. This equipment generates the cost functions. The ability to remotely disconnect and reconnect energy flow enables both labor savings and revenue assurance and improves service quality. Furthermore, the implementation of connect/disconnect devices will enable the deployment of prepaid metering services.

In addition, the customer's benefit to this technology is faster restoration. Whereas before if service was disconnected, the customer had to wait for a crew to be dispatched to reconnect service; now, service can be reinstated by a customer service representative remotely.

Benefits for Oshawa: With remote service switching feature on the smart meters, Oshawa could respond to requests to turn service on or off without driving to customers' premise, thereby reducing truck rolls and response time. Additionally, Oshawa could see an increase in cash flow through the development of a more coordinated system. Furthermore, reconnection of service will be done quickly, and will been seen as an improvement to the customer. All of this reduces the overhead costs associated with customer service and collections. These savings can then be passed down to the customer.

Industry Trends: The costs of included remote disconnect/ re-connect functionality has dramatically decreased in recent years. No longer is an expensive disconnect collar required; meters are now manufactured with the disconnect/reconnect switch fully integrated inside the meter ("under glass"). As a result, the functionality is more user-friendly and cost effective. Please see below for a partial list of utilities who have taken advantage of the disconnect/reconnect meter functionality:

- Southern California Edison
- San Diego Gas & Electric
- Duke Energy
- City of Ruston, LA
- Garland Power & Light
- Salt River Project, AZ

Customer Service

Oshawa has demonstrated a cultural and business desire to continually improve its operations and services to customers. At the end of the day, the customer is the key component that has to benefit the most from the value of service that smart grid provides. Smart grid programs will allow Oshawa to realize substantial operating services, especially in customer service. Key opportunities exist to offer better customer service, which includes improved reliability, bill accuracy and reduced inconveniences that include self-reads or the lack of outage notification. These are sometimes referred to as "soft benefits" and have been estimated by some to account for up to half of the total quantifiable utility benefits, with industry standards averaging approximately $0.27 per meter per month. The immediate benefit in implementing smart grid programs is usually observed with the reduced load in call centers, where customers call in regarding billing errors, rescheduling meter reads or outage reporting. This allows utilities to provide better customer service.

The customer service benefits are primarily associated with early detection of meter failures, outages notification, faster service restoration, billing accuracy improvements, flexible billing cycles, variety of time-based rate options to customers, and creating customer energy profiles for targeting energy efficiency/demand response programs. For Oshawa, improvement in customer service will be realized with the tie-in of an Outage Management System (Distribution Operations), AMI Process Redesign, Remote Connect/Disconnect and Prepaid Metering (Metering).

Billing System Redesign

Overview: Every implementation of a new technology is most certainly followed by a change in business process/operations. With AMI implementation and installment of additional supporting programs, a significant redesign and approach in utility's billing system and business processes is critical to realize the benefits of the respective programs (meter-to-bill process).

Benefits for Oshawa: Oshawa PUC follows the Ontario energy plan that calls for all electric meters below 50 kW to be supported by an automated meter. Meter data is gathered through Oshawa's ODS system, then transmitted to the provincial MDMR for billing validation, and ultimately to a third party CIS for bill presentment. While the system currently in place follows Ontario requirements, the impact to customer service is such that customer service representatives are limited in their capability to access system data in support of customer needs. By fully integrating these systems to report through a central repository of data, Oshawa PUC customer service representatives can deliver enhanced service to its customers.

Industry Trends: Successful AMI deployment projects that incorporate additional programs (e.g. MDM, prepay, TOU, etc.), typically feature a billing system redesign (parallel with CIS). The integration of existing and future systems allows the utility to improve their data integrity by delivering accurate and reliable billing services, reduce duration of non-pay disconnect process, flexible billing, pre-pay, enable ToU and variable rate billing, ultimately resulting in increased customer satisfaction.

Enhanced IVR

Overview: Traditional Interactive Voice Response (IVR) platform is an automated telephony system that interacts with callers, gathers information and routes calls to the appropriate person. Utilities typically use IVR for automated communications and commerce as well as communications with employees, business partners, and/or general public. Traditional IVR is typically used only to gather inbound information, with limited outbound message broadcasting. An enhanced IVR that is integrated across the enterprise will benefit utility by having a smooth operation and providing better customer service.

Benefits for Oshawa: An enhanced IVR will allow Oshawa to provide better customer service, where information is provided in a two-way communication system. Enhanced IVR will be able to provide automatic broadcast notices to customers (late payment, delinquency, out of money in prepay) in the method that they prefer, either by call, text, email alert, etc. In terms of outage management systems, enhanced IVR plays a bigger role in determining outage locations (based on location of caller) and can provide adequate information to customers regarding the outage (location, cause, expected restoration etc.).

Industry Trends: Enhanced IVR systems have been implemented not only in utilities, but also in any businesses with attention to customer support. Examples of utilities implementing enhanced IVR systems include:

- Lafayette Utilities System
- Grand Bahama Power Company
- City of Florence Utilities
- Citizens Energy Group
- Tucson Electric Power

Distribution Operations

A significant grouping of benefits involves improved capabilities for responding to electrical faults (i.e., short-circuits) in the utility's Electric Delivery System. The smart grid would provide improved capabilities for activating protective relays (e.g., tripping substation feeder breakers to protect fuses), and instantly switching circuits, as needed, to protect the system. It would provide improved controls for automated balancing, shedding, and transferring of loads; and it would provide advanced decision support systems for human operators.

Smart grid programs also create the ability to conduct real-time, condition-based monitoring of core equipment. This would allow continuous analysis of conditions (temperature, pressure, etc.) and operating parameters - which would extend equipment life, prevent major failures, and reduce repair costs. Remote surveillance and control also would enable quicker problem resolution, and reduce unplanned events and associated costs. Given these benefits, electric utilities are emphasizing distribution automation-related application in planning smart grids.

SCADA Upgrade

Overview: SCADA (Supervisory Control and Data Acquisition) is a system operating with coded signals over communication channels so as to provide control of remote equipment (using typically one communication channel per remote station). The supervisory system may be combined with a data acquisition system by adding the use of coded signals over communication channels to acquire information about the status of the remote equipment for display or for recording functions. It is a type of industrial control system (ICS). Industrial control systems are computer-controlled systems that monitor and control industrial processes that exist in the physical world. SCADA systems historically distinguish themselves from other ICS systems by being large-scale processes that can include multiple sites, and large distances.

Benefits for Oshawa: Oshawa has a SCADA system that connects its substations and monitors the health of the distribution network. However, as many utilities have learned, the deployment of a high degree of system automation requires additional advancement of the SCADA system in order to ensure full system interoperability. Doing so will enable Oshawa to ensure that service reliability to customers is maximized.

Industry Trends: In increasing number of utilities have upgraded their SCADA networks in support of extensive distribution automation deployments, including:

- CenterPoint Energy
- City of Burbank, CA
- Duke Energy
- Hydro One
- Con Edison

- Pacific Gas & Electric
- Xcel Energy

Voltage Monitoring

Overview: Integrated Volt/VAR Control (IVVC) throughout the supply delivery system can help to identify the cause of line losses and ultimately reduce them over time. In response to measurements, load tap changers in substation transformers can reduce voltage to minimize losses. Automated capacitor banks are used for central power factor correction at main and group distribution boards. Power factor correction means that reactive power charges levied by electricity suppliers can be avoided. Improving the power factor has a direct impact on the amount of loss that occurs. By reducing this, the emissions and costs of associated generation can also be reduced.

Benefits for Oshawa: Oshawa's relatively short feeders suggest that line losses may be modest. However, the lack of visibility into the condition of the network compromises the overall service reliability to support customers. By integrating a dedicated Volt/VAR program, Oshawa can ensure that service reliability is delivered at the highest possible level.

Industry Trends: Historically, utilities have controlled the voltage level at the point of regulation, either at the load-tap changing transformer (LTC) or line regulator, so that the voltage at all points along the feeder is maintained within established standards. Capacitor banks are then added along the distribution line to maintain the power factor as high as possible for reduced losses and additional voltage support. Typically, the controllers for these devices operate the system based on a standard set of parameters and the local conditions at the device. With the proliferation of communication capability into every area of the electrical system over the last decade, utilities now utilize the data from communicating devices to aid in improving the power flow across the electrical system. Utilities also can use sensors along the line, including AMI meters, as communication nodes to relay information back to the regulation devices and capacitor banks. This remote feedback allows utilities to fine tune the system for its most efficient operation for any given time of the day or year.

Outage Management

Overview: Outage Management System greatly improves a utility's capability to improve overall Quality of Service (QoS) across the board. An OMS will improve communication with Oshawa's customers, provide rapid and reliable information on planned and unplanned outages, and improve Oshawa's response in its restoration efforts. Predictive modeling based on AMI and SCADA data is capable of identifying potential problems before they become outages. Automated notification of single service point outages within 30 seconds of occurrence greatly speeds reaction time, thereby reducing outage durations. Integration with Interactive Voice Response (IVR) and email automatically notifies customers of outages at the individual meter level. Integration with dispatch and mobile workforce management systems can automatically dispatch and preposition equipment to respond to outages more quickly, as well as prioritizing work orders to have the most significant restorative impact.

Typical functionality of modern OMS includes:

- Integration with AMI system to receive outage reports and QoS data automatically
- Reliability modeling and analysis of existing and proposed circuits
- Identification of potential foliage or other sources of intermittency before they cause outages
- Provide customers automated notification when outages occur or are resolved, including estimated time to restoration and preconfigured utility messages
- Predict outages based on Quality of Service (QoS) information from AMI and SCADA
- Automatically dispatch work orders based on outage location, priority, or other configurable criteria
- Automatically generate regulatory reporting statistics on demand or as scheduled

Benefits for Oshawa: Lacking an established OMS, Oshawa depends on human intervention to address outage events. While many utilities have been following this approach for many years, the overall industry trend has been moving toward the adoption of outage management programs that provide dynamic capabilities to monitor and respond to events on the line on a real-time basis. Initial calculations suggest that the development of an outage management program could eliminate nearly one million minutes of customer outage on an annual basis by the year 2024.

Industry Trends: A 2013 industry study surveyed 14,000 North American utility employees; 64% indicated that restoration management is a top priority. This is largely driven by developments in the technology; while the technology for high-powered OMS has existed for quite some time, current developments enable greater functionality of the system by leveraging access to meter data and enhanced system integration capabilities. Canadian utilities that have adopted OMS include BC Hydro, Hydro One, Toronto Hydro, Hydro Québec, Nova Scotia Power, and New Brunswick Power.

Automated Switching

Overview: Automated switches can use information from protective relays at adjacent substations to isolate faulted sections of the supply line to restore service to the substation. Adaptive relaying can activate protective relays during storm conditions and trip substation feeder breakers for faults to protect fuses in the zone. High-speed transfer switches will instantly remove disturbed sources and replace them with clean, backup power supplies. Automated balancing, shedding, and transferring will not only improve performance, but also reduce capital costs, crew dispatching costs and restoration efforts. Automated feeder ties, distributed resources and advanced decision support systems work together to reduce and move load.

Benefits for Oshawa: The Oshawa PUC distribution network currently features 18 underground vaults with manual switches. Today, when there is a need to operate one of these switches, it calls for one of

Oshawa PUC's lineworkers to physically go underground and manually operate the switch. This can be very dangerous to the worker in the event of an arc. As such, the move to automated switches will result in a higher level of safety for Oshawa's lineworkers.

Industry Trends: The development of robust automated switches has resulted in many electric utilities to employ these devices across the network. Among many others, Toronto Hydro has already successfully deployed automated switches in underground vaults.

Distributed Resources

Another source of benefits involves the integration and control of distributed resources, involving elements not tied to convention central station generation, including distributed generation, energy storage, and demand response. Distributed technologies have the potential to increase asset utilization through peak shaving; enhance reliability through distributed backup units; and increase operational flexibility and efficiency through the availability of resources close to the end consumer. These are very important benefits, given mandates for aggressive development of renewable resources (many of which are distributed in nature), and given the intermittent/variable performance characteristics of many renewable resource technologies. In order to make increased use of renewable resources, while maintaining system reliability, new and enhanced controls will be needed.

Distributed resource applications need to be considered as part of the overall smart grid strategy for any utility in order to react to these changes and prepare for future ones. These applications have the potential to improve asset utilization through peak shaving; enhance reliability through distributed backup units; and increase operational flexibility and efficiency through the availability of resources closer to the end consumer. Introducing a mix of these applications can also reduce the high cost of cycling peaking plants and the Greenhouse Gases (GHG) emissions that come from non-renewable forms of generation. At the end of the day, the smart grid will redefine the way in which utilities operate and electricity is managed and consumed.

Transmission Management

Overview: At the transmission level, smart grid systems allow utilities to implement next-generation supply automation systems that monitor loads at different points in the Electric Delivery System, leveling, shedding, and shifting loads (e.g., from high to low points), as needed, to keep the system balanced. This kind of control will lead to increased system reliability by resolving congestion faster and avoiding outages. In the future, such controls may gain “self-healing” capabilities that respond to threats, material failures, and other destabilizing influences by preventing or containing the spread of disturbances.

Benefits for Oshawa: Oshawa’s controls over the two transmission feeds it receives are based on manual operation by system operators. Given the demands that exist in managing peak loads, a system operator has a need to quickly identify the optimal approach to addressing switching between two diverse wholesale power feeds. By developing an automated system to support this function, Oshawa stands to reduce system peak. In addition, this program offers the potential to reduce the risk of system overloading by instituting dynamic controls.

Industry Trends: Employing system automation to support transmission management is a well-established practice among virtually every major North American utility. The technology is well-proven and is rapidly being adopted by an increasing number of municipal utilities and electric cooperatives.

Demand Management

Overview: In Ontario's Long Term Energy Plan, the Minister of Energy indicated his support for DSM programs, stating "Smart meters and consumer demand response programs are allowing ratepayers to control and understand their electricity consumption better while additional smart grid technologies are being used by utilities to operate an advanced, more efficient and modern grid."

Demand Management involves customers' ability to control their costs by reducing consumption during high cost periods. The smart grid would allow customers to save money in two ways in the short-term: (1) by avoiding usage during high cost periods (those customers who respond by curtailing usage), and (2) by lowering wholesale market prices (those customers who don't respond: when the utility's load drops, it pushes down market clearing prices for all customers). In the long-run, the smart grid would allow the utility to defer investments (on behalf of customers) in new capacity. It also would benefit society at large, if reductions in peak consumption lead to reductions in emissions (e.g., of greenhouse gases and other conventional pollutants). We evaluated two discrete benefits in this group, as follows:

- Energy Savings – By shifting consumption from peak periods to off-peak periods, the utility and the consumer alike can generate positive value by avoiding consumption during high priced energy periods, reducing market clearing prices, and reducing overall capacity costs
- Reduced Emissions – By reducing peak demand, the utility lessens its generation requirements, thus reducing the overall carbon emissions associated with electric power generation.

Benefits for Oshawa: Oshawa PUC is recommended to begin the process of exploring opportunities to integrate demand management programs into the overall power grid from all sources – distributed generation, energy storage, and demand response. While this is a rapidly developing field, there are clear opportunities to create benefits that span financial, environmental, and operational frameworks. In addition, this program offers the opportunity to support the vision set forth by the Ontario Long Term Energy Plan.

Industry Trends: A 2013 industry study indicated that of 1,342 demand management programs from around the world, almost 95% are being offered in North America. On a worldwide basis, programs identified as addressing capacity and economic market objectives represent a total of 732 and 585 programs, respectively. There are also additional programs being explored that involve energy arbitrage and ancillary savings that are not currently considered for Oshawa.

Load Control

Overview***:*** Direct load control allows utilities to reduce peak usage and prevent outages from system overloads by directly controlling the operation of customer equipment. Overall load reduction and balance throughout the system could improve asset use efficiency, which may defer or slow the rate of expensive investments in new capacity. Peak hours cause spikes in energy demand and force utilities to buy electricity in wholesale open markets at high prices. By shifting energy demand to off-peak hours, load control programs flatten the curve, thus improving asset use and decreasing the utility's reliance on expensive open market energy purchases.

Benefits for Oshawa: Coupled with a dedicated demand management program, Oshawa can develop real benefits through a load control initiative. By entering into agreements with customers to manage select devices during peak power events, Oshawa can effectively reduce system peaks and lower overall costs. Furthermore, we estimate that the adoption of these two programs offer the potential to reduce system peak by 961 kW by 2024 and offers the potential to reduce 3.34 metric tons of CO_2 emissions over a ten-year period.

Industry Trends: Most utilities have already been pursuing some version of load control for decades, using older technologies that lacked validation potential. With more robust technical controls today, virtually every utility exploring demand side management programs is evaluating load control as part of the portfolio of options.

Conclusion

The myriad of trends facing utilities – aging workforce, aging infrastructure, environmental concerns, rising costs, integration requirements – serve as the drivers for smart grid activity. However, in the end, the deployment of a smart grid must be conducted in a way that ensures that the incremental benefits justify the incremental costs incurred. Utilities, their customers, and regulators should agree on the answer before capital is committed. It will require a careful accounting of benefits and costs, and it will require parties to take the long view.

Each stakeholder must consider the cost of a 'non-Smart grid strategy'. Embedded within this issue is the evaluation of the likely state of not pursuing grid automation and the impact that such decisions will have in future years. Once this assessment has been completed, each utility can consider the true value proposition of the Smart Grid versus a 'Do Nothing' Strategy. Rising costs for utilities that do not achieve Smart Grid efficiencies could have a more detrimental financial impact for customers than smart grid capital requirements call for. Oshawa PUC engaged UtiliWorks specifically to address this issue – to identify those programs that offered value to its customer base and aligned with the stated goals of the Ontario Long Term Energy Plan. The result of the research and analysis conducted as part of this effort has led to the careful evaluation of 15 different programs – of which UtiliWorks is recommending 8, 5 already in process to some extent and 3 others that we believe should begin.

Many of the applications sought by utilities also benefit the customers. UtiliWorks analysis of industry estimates suggest that a 50% penetration of smart grid technologies in transmission and 25% in distribution could reduce annual outage and Power Quality (PQ) losses by $1.5B across Canada. Poor PQ leads to increased electrical losses and shorter equipment life, which has both economic and environmental impact. Avoided productivity losses from PQ to C&I customers could shed billions of dollars of waste from the economy. Costs associated with events at commercial facilities from banks to data center can be thousands to millions per event. Scrapped materials, customer dissatisfaction, lost productivity and safety concerns have led to an estimated annual cost for reliability and power quality defects of at least $10 billion.

Improving operational efficiencies at the utility will help fight rising costs and will offer future savings to customers. PJM and NY ISO's wholesale electricity markets have reduced average electric rates by $430M – 1.3B/year. In 2005, over $40B/year was spent by IOUs to operate and maintain the power system; it is estimated that about 10%-20% of this could be eliminated through adoption of smart grid programs.

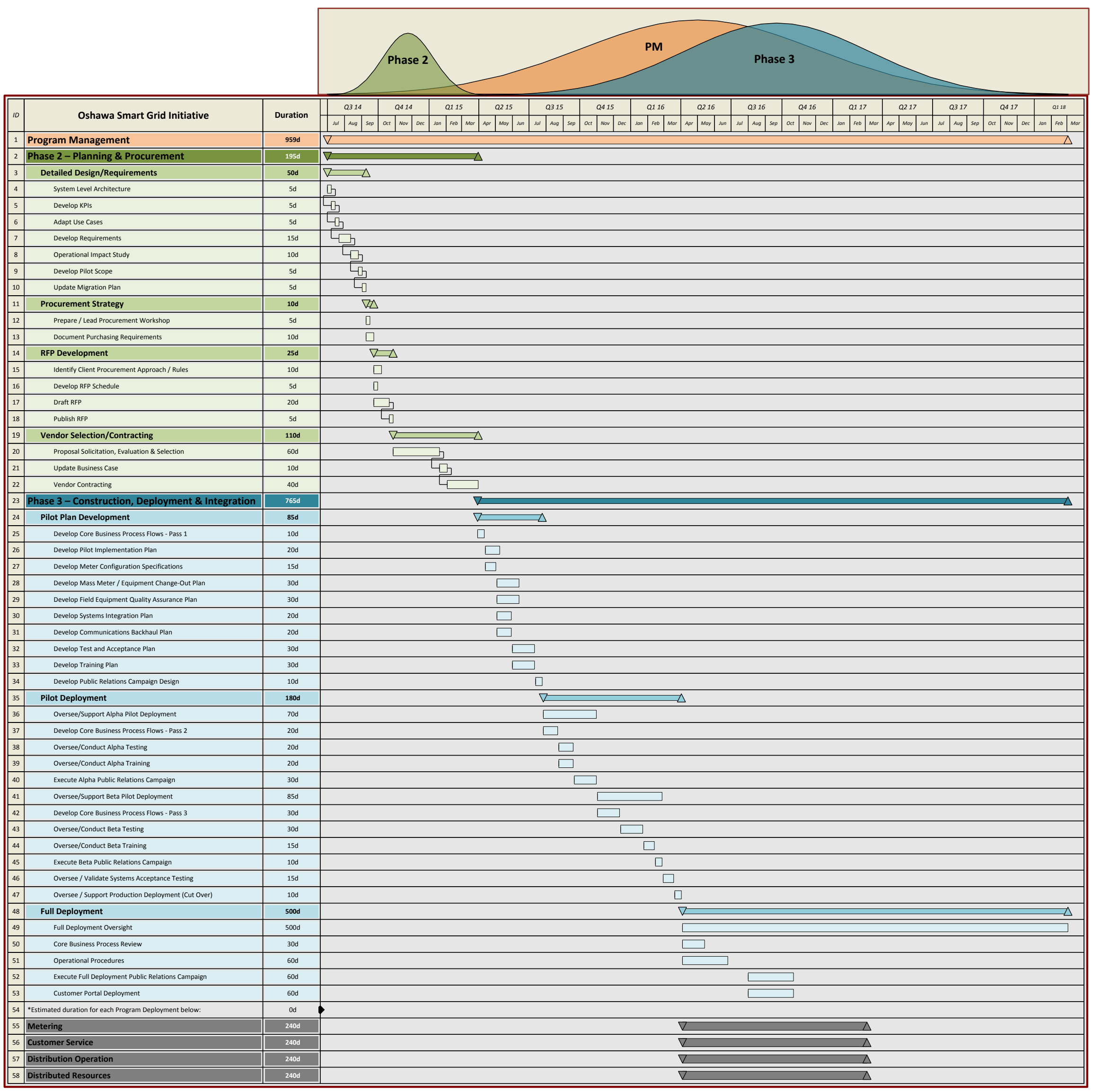
Including in the utility benefits is that a Smart Grid allows for increased flexibility in the products and services that are offered to customers. Enabling customers to monitor and modify consumption habits or integrate distributed generation resources improves satisfaction as well as the potential for avoided or deferred grid expansions. Pacific Northwest National Laboratory (PNNL) researchers estimated that smart (grid friendly) appliances costing $600 million could provide as much reserve capacity to the grid as power plants worth ten times that. A PNNL study found that, over 20 years, significant amounts of U.S. power infrastructure additions could be avoided. EPRI estimates that the societal cost-benefit ratio for grid modernization is 4 to 1 relative to utility benefits. They estimate the benefits to be between $638 and 802 billion with an investment of $165 billion over the next 20 years. The University of San Diego's recent business case included $1.4B in system benefits as well as $1.3B in societal benefits with an IRR of 26%.

Furthermore, in a carbon-constrained world, the value of CO_2 reduction attributable to the smart grid may prove essential to justifying the costs of new infrastructure. The cost of environmental impact is also large and growing; hence the environmental benefits of a modern grid will generate billions of dollars in benefits each year. Improved network operations, increased end-use efficiency, renewables integration and the advent of PHEVs are all sources of carbon reduction. Every kWh saved by the efficiencies of the modern grid results in reduced expenditures on pollution controls at power plants. As the smart grid is used to achieve operational benefits like reduced line losses and congestion, the carbon emissions for the associated production is also reduced. Ten percent of electricity is lost in transmission and distribution, which is equal to approximately 23 million barrels of crude oil or about 7.2 million metric tons of CO_2.

Appendix 1 – Potential Project Timeline

UtiliWorks recommends a phased approach to utility modernization starting with the projects that establish the necessary foundation. The first phase typically includes the procurement and deployment of an AMI System as the foundation. Other projects such as an MDM System, Distribution Automation, Demand Response, Outage Management System, Mobile Workforce Management, Prepay etc. are add-on solutions which need to be tightly integrated to achieve the greatest potential benefits.

Based on the information available to UWC at the time of publishing, a sample program timeline is depicted below. As more information becomes available (programs to be included, sequencing, etc.) during the proposed next phase of this project – Planning and Procurement – UWC can better conclude the scope and timing of other Smart Grid projects.



Appendix 2 – Capital Budgeting Forecast

Below is the capital budget forecast for the Oshawa system over a ten-year period:

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Metering	$ 727,152	$ 207,660	$ 212,941	$ 219,036	$ 224,922	$ 14,616	$ 14,814	$ 15,048	$ 15,264	$ 15,498
Customer Service	$ 185,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operations	$ 1,425,000	$ 380,000	$ 380,000	$ 418,000	$ 456,000	$ 38,000	$ 38,000	$ 38,000	$ 38,000	$ 76,000
Distributed Resources	$ 949,905	$ 659,505	$ 774,300	$ 887,825	$ 1,022,540	$ 526,809	$ 542,734	$ 564,996	$ 570,417	$ 582,888
Total	$ 3,287,057	$ 1,247,165	$ 1,367,241	$ 1,524,861	$ 1,703,462	$ 579,425	$ 595,548	$ 618,044	$ 623,681	$ 674,386

Project Prioritization Results: 2014 - 2019

The following figure summarizes the results of OPUCN's Asset Investment Prioritization Tool modelling for 2014 – 2019 capital investments.

CAPITAL PROJECTS			Risk Consequences			
			0-1	1-2.5	2.5-4	4-5
			Minor	Moderate	Major	Critical
Risk Probability	4-5	Almost Certain	0	0	2	1
	2.5-4	Likely	0	1	89	9
	1-2.5	Somewhat Likely	0	1	0	0
	0-1	Unlikely	0	0	0	0

Of the 103 Projects identified, there is one project that is "critical" (critical consequence and almost certain probability) and 11 with "very high priority" (critical or major consequence and likely or almost certain probability). There are 89 projects that are high priority.

Projects deemed as "very high priority" or "critical" should be completed immediately or within the same year as they are critical to maintenance of reliable delivery service or have significant safety, environmental or compliance consequences.

The balance of the projects are more amendable to scheduling in consideration of additional factors, such as available resources, cost efficiencies, rate impact smoothing, etc.

The 103 projects identified and analyzed are listed below in order of prioritization:

The 103 projects identified and analyzed are listed below in order of prioritization:

Critical

1) MS5 T1 - Replace 25kVA Power Transformer including Oil Containment

Very High Priority

1) Porcelain insulators replacement program as per AMP (13.8kV, 100A LBS) - Phase 2

2) Porcelain switch replacement program as per AMP (13.8kV, 100A, LBS) - Phase 2

3) MS14 – Replace Metal clad Switchgear (Arc Flash Resistant)

4) MS14 - 13.8kV Feeder lead cable replacement (pot heads leaking)

5) MS13 OH/UG Plant Upgrades

6) Wilson TS to Thornton TS Load Transfer (Phase 2) - Gibb St - Stevenson to MS14

7) Wilson TS to Thornton TS Load Transfer (Phase 2) - MS11 - 11F4 to 11F3 Re-cabling

8) Substation Breaker Replacement Program (MS5 & MS14) - 2014

9) Substation Breaker Replacement Program (MS10 & MS11) - 2015

10) Substation Breaker Replacement Program (MS2 & MS15) – 2016

11) 7 William St. - Downtown UG below grade Vault Reconstruction

High Priority

1) Wilson TS to Thornton TS Load Transfer (Phase 2) - Gibb St. - Stevenson to MS14

2) Wilson TS to Thornton TS Load Transfer (Phase 2) - MS11 - 11F4 to 11F3 re-arrangement

3) Wilson TS - HONI's ROW - Rear Lot 44 KV distribution Plant Upgrade. Aged Plant reaching end of life. Existing customers' encumbrances are obstacles to

replace plant upon in-service failure and need to be removed to prevent significant major outage.

4) Wilson - Wentworth to Bloor - 20 wood poles 1 cct 44kV 1 cct 13.8kV 900m – OH Rebuild

5) Adelaide St E - Wilson to Harmony 900m, 22 Poles, 4 Tx, one 13.8kV 3 phase cct – OH Rebuild

6) Rebuild Sorrento Ave, Homestead Crt., Cooper St., Siena Crt. and Salerno St. – OH Rebuild

7) Southgate Dr., Southdale Ave., Southdown Dr., Southridge St. - UG Cable Replacement

8) Distribution Automation (Smart Grid Project) - Phase 1 - Downtown Vaults Automation

9) Distribution Automation (Smart Grid Project) - Phase 2 - Downtown Vaults Automation

10) Distribution Automation (Smart Grid Project) - Phase 3 - Downtown Vaults Automation

11) Rebuild Londonderry St., Castlebar Cres., Kilkenny Ct., Cavan Ct., Arklow Ave. - UG Cable Replacement

12) 100 Rideau St. - UG Cable Replacement

13) Olive Ave. - resulting from Dec 2013 Ice Storm Accepted by Capital committee Feb 2014

14) Simcoe St N Rossland to William - OH Rebuild

15) Park Rd. Wentworth to Stone including Lakefield/Beaupre/Tremblay/Kenora/ Gaspe/Laurentian/Lakeview/Lakeside/Lakemount/Evangeline/Montieth/Bala/Lake view - OH Rebuild

16) Regional Planning - Address Transmission Capacity at Thornton TS – 2 Feeders Requirement

17) Keewatin (Melrose, Applegrove, Oriole, Willowdale, Springdale) - OH Rebuild

18) Distribution Capacity - Construct new MS 9 - 13.8kV Substation to address load growth in North Oshawa mainly due to extension of 407 (2015)

19) Regional Planning - Address Transmission Capacity at Thornton TS – 2 Feeders Requirement (2015)

20) Down Cres., Delmark Crt.- UG Cable Replacement

21) Camelot Dr., Merlin Crt., Percival Crt., Lancelot Cres. - UG Cable Replacement

22) Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave

23) Chandos Ct., Calvert Ct. - UG Cable Replacement

24) Athabasca (Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield) - OH Rebuild

25) 1100 Oxford St - UG Cable Replacement

26) 1010 Glen St - UG Cable Replacement

27) Backyard - Rear Simcoe & Masson; Rear Masson & Harry - OH Rebuild

28) 1333 Mary St. N - UG Cable Replacement

29) 44kV oil circuit breakers – 2015 – Proposed 4 OCB replacements

30) 44kV oil circuit breakers – 2016 - Proposed 4 OCB replacements

31) 44kV oil circuit breakers – 2017 - Proposed 3 OCB replacements

32) Northdale Ave., Mohawk St., Beatrice St. W - UG Cable Replacement

33) Athabasca St., Suton Crt., Maclaren St., Erinlea Ave., Sutton Ave. - UG Cable Replacement

34) Aruba Cres, Aruba St, Waverly St N, Bermuda Ave, Antigua Cres – UG Cable Replacement

35) Rossland - Ritson to Wilson - OH Rebuild

36) Bloor St. - Oliver to MS11 – OH Rebuild

37) Eastlawn, Winter, Mackenzie, Labrador - OH Rebuild

38) MS10 - 10F1 & 10F6 - Lead cable replacement, lead potheads, feeder poles

39) Construct new MS 9 - 13.8kV Substation to address load growth in North Oshawa mainly due to expansion of 407 (2016)

40) Regional Planning - Address Transmission Capacity at Thornton TS – 2016

41) Landsdowne - Dover, Digby, Surrey, Sussex - OH Rebuild

42) Rebuild Fisher St., Albert St., Avenue St & Quebec St. – OH Rebuild

43) Grenfell South of Gibb, Harland, Montrane - OH Rebuild

44) CherryDown Dr. and Sunnybrae Dr. - UG Cable Replacement

45) Annandale St., Capilano Cres. and Capiland Crt. - UG Cable Replacement

46) Tennyson Crt – UG Cable Replacement

47) Birkdale St., Muirfield St., Pinehurst to Subbingham - UG Cable Replacement

48) Traddles, Dickens, Wickham – UG Cable Replacement

49) 291 Marland Ave. – UG Cable Replacement

50) 321 Marland Ave. – UG Cable Replacement

51) 282-290 Marland Ave. – UG Cable Replacement

52) Distribution Capacity - Construct new MS 9 - 13.8kV Substation to address load growth in North Oshawa mainly due to extension of 407 (2017)

53) Distribution Automation/ Smart Grid – UG Self-Healing Automated Switches - 2016

54) Regional Planning - Transmission Capacity at Wilson TS – 2017

55) Distribution Automation/ Smart Grid – OH Self-healing Automated switches - 2017

56) Pole Replacement Program – 2016

57) Pole Replacement Program – 2017

58) Pole Replacement Program – 2018

59) Pole Replacement Program – 2019

60) Grandview, Beaufort and Newbury - OH Rebuild

61) 401 Wentworth Ave. - UG Cable Replacement

62) Central Park Blvd. N - Brentwood, Homewood to Harwood – UG Cable Replacement

63) Mary - Rossland to Aberdeen - OH Rebuild

64) King St. E 10F1 (Keewatin to Townline) - OH Rebuild

65) Outlet Dr - Birchcliffe Crt., Lakeview Park Ave. & Valley Dr. - UG Cable Replacement

66) Gladfern, Galahad, Gentry, Gaylord – UG Cable Replacement

67) Marwood Dr. - UG Cable Replacement

68) Regional Planning - Address Transmission Capacity at Wilson TS – 2018

69) Regional Planning - Address Transmission Capacity at Wilson TS – 2019

70) Distribution Capacity - Construct new MS 9 - 13.8kV Substation to address load growth in North Oshawa mainly due to extension of 407 (2018)

71) Proposed OH 13.8kV distribution feeders due to new MS9 (2018)

72) Distribution Automation/ Smart Grid – OH Self healing Automated switches - 2018

73) Proposed OH 13.8kV distribution feeders due to new MS9 (2019)

74) Julianna and Bernhard - OH Rebuild

75) Riverside South - Palace and Hosein - OH Rebuild

76) Vimy Ave., Lasalle Ave. - OH Rebuild

77) Ormond Dr., Everglades, Palmetton, Pompano Crt., Miami Crt. - UG Cable Replacement

78) Beaufort Crt Townhouse – UG Cable Replacement

79) Central Park Blvd. N, Exeter St and Trowbridge - UG Cable Replacement

80) MS5 T2- Replace 25kVA Power Transformer including Oil Containment

81) Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Crt., Carmen Crt - OH Rebuild

82) Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glen Castle - OH Rebuild

83) Riverside North - Regent, East Haven, East Grove, Eastdale, Eastborne, East Glen, Florian Crt. - OH Rebuild

84) Waverly - Cabot, Cartier, Montlare, Harlow - OH Rebuild

85) Distribution Automation/ Smart Grid – Voltage Monitoring (substation controls and communication devices) - 2018

86) Distribution Automation/ Smart Grid – OH Self healing Automated switches - 2019

87) Distribution Automation/ Smart Grid – transmission monitoring Smart Fault indicators – 2018 - 2019

88) Distribution Automation/ Smart Grid – Voltage Monitoring (Volt Var management system) - 2019

Moderate Priority

The remaining 3% were identified as moderate risk as shown below but are required to meet the OEB and Ministry mandate.

1) LT - Townline Rd North (Middle) - Columbus to Townline, then Townline N of Columbus

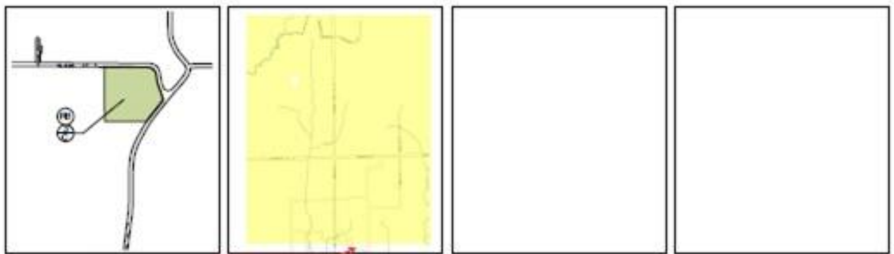
2) LTLT - Townline Rd North (Upper) - then up to Howden (LTLT)

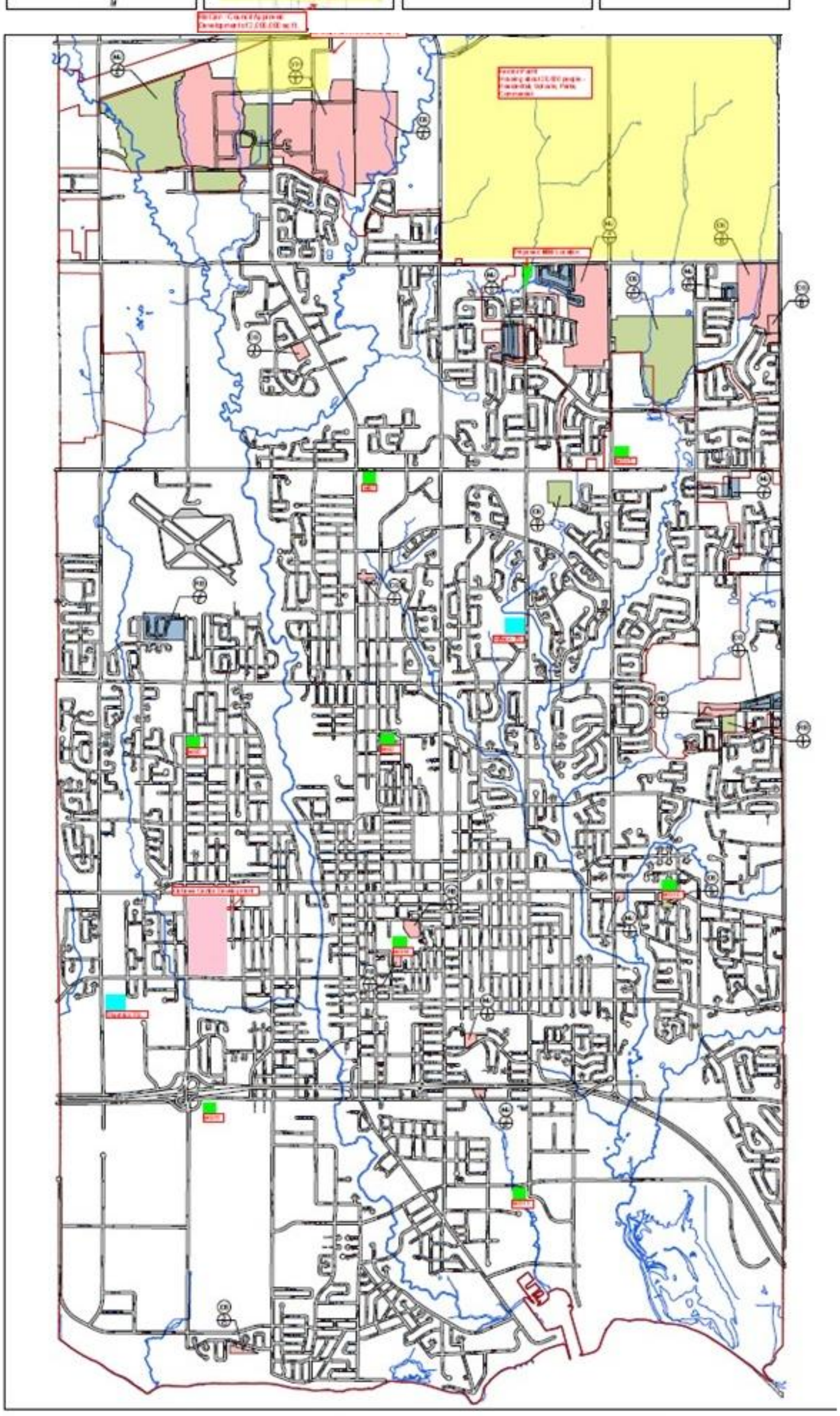
3) Smart Grid Pilot Capital Project Phase 2 - Micro Grid UOIT – 2015 - 2016 Ministry Approved

Filed: 2015-01-29
EB-2014-0101
Exhibit 2
Tab B
Schedule 6

Residential Subdivision Development Activity

City of Oshawa
Development Services Department





Legend

CONDOMINIUM/ SUBDIVISION PLAN APPROVAL STAGES	LEGEND	NUMBER OF UNITS					
		S.D.	Semi	Th.	S. Th.	Apt.	Total
PROPOSED DRAFT PLAN		762 53.70%	178 12.54%	323 22.76%	0 0%	156 11.00%	1419 100%
DRAFT APPROVED		1966 54.31%	142 3.92%	78 2.16%	652 18.01%	782 21.60%	3620 100%
REGISTERED		705 63.12%	0 0%	0 0%	36 3.22%	376 33.66%	1117 100%
REGISTERED NO PERMITS ISSUED	R.N.P.I.	148 38.95%	0 0%	0 0%	0 0%	232 61.05%	380 100%

Effective Date:
2nd Quarter, June 2013

Abbreviations:
S.D. - Single Detached
Semi - Semi-Detached
Th. - Townhouses
S. Th. - Street Townhouses
Apt. - Apartments
R.N.P.I. - Registered No Permits Issued

Planner	Init
Paul Ralph	PR
Valerie Hendry	VH
Robert Bedic	RB
Cambell Steuart	CS
Morgan Jones	MJ
David Sappleton	DS

Notes

1. Units are considered built when the building permit is issued.
2. Plans having five (5) or less units for which no building permit has been issued are not shown on this map.
3.
4.

Capital Expenditure Details by OEB Filing Guidelines Chapter 5 Investment Category

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional “Miscellaneous Project” category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
SYSTEM ACCESS							
CUSTOMER SERVICES - EXPANSIONS AND CONNECTIONS	Non Discretionary Subdivisions & individual residential , commercial curomers' service conection requests	$650	$545	$560	$560	$575	585
REVENUE METERING	Required Revenue Meters forecasted for services	$280	$475	$480	$640	$490	490
OEB's MIST Metering - Interval/smart meters? For Accounts >50kW	Potential replacements and new MIST metering as per OEB mandate	$0	$150	$150	$125	$125	125
Smart Grid Research & Development - Micro Grid project (Ministry Approved)	Ministry approved Project - investment is OPUCN's contribution	$0	$110	$45			
LTLT - Townline Rd North (Upper) -then up to Howden (LTLT)	Joint Use with Hydro One poles (37 poles, 2,100m)	$165					
LTLT - Townline Rd North (Middle) - Columbus to Townline, then Townline N of Columbus	Joint Use with Hydro One poles (9 poles, 480m) and Bell (approx 15 poles, 720m)	$230					
	NET TOTAL SERVICES, METERING & REGULATORY	**$1,325**	**$1,280**	**$1,235**	**$1,325**	**$1,190**	**$1,200**
	Total Contributions from Expansions	**$1,560**	**$650**	**$675**	**$690**	**$705**	**730**
	Total GROSS CONNECTIONS, METERING REGULATED COSTS	**$2,885**	**$1,930**	**$1,910**	**$2,015**	**$1,895**	**$1,930**

HWY 407 Extension - Plant relocation - Various Locations (100% contribution for like for like replacement) - NON DISCRETIONARY							
407 Extension - Winchester & Thornton Intersection - **Carried over from 2014**	Estimated $2 million based on Consultant estimates to relocate existing plant UG. OPUCN to contribute approx 270K for additional future ducts with **ECGP contributing $1,730K**. Total Project ~$2million	**$20**	**$250**				
407 Extension - Winchester & Simcoe Intersection - **Carried over from 2014**	Estimated $960K based on Consultant estimates to relocate existing plant Underground. 407 ECGP willing to pay for OH solution and **contribute $440K** to the project with OPUCN picking up $520K for UG section.	**$20**	**$500**				
407 Extension - Bridle Rd Intersection - To be Completed in 2014	Estimated $220K based on Consultant estimates to install future UG infrastructure for future load development north of 407. OPUCN cost of $220K for additional future ducts.Total Project costs~ $220K	**$220**	**$0**				
407 Extension - Ritson Rd Intersection - **To be Completed in 2014**	Estimated $470K based on Consultant estimates to relocate existing plant UG. OPUCN to contribute $120K for additional future ducts. **ECGP contribution ~ $350K**	**$120**	**$0**				
407 Extension - Wilson Rd Intersection - **Completed in 2014**	Estimated $470K based on Consultant estimates to relocate existing plant UG. OPUCN to contribute $125K for additional future ducts. **ECGP contribution ~ $345K**	**$50**	**$0**				
407 Extension - Harmony Rd Intersection - **carried over from 2014 to 2015**	Estimated $1 million based on Consultant estimates to relocate existing plant UG. OPUCN to contribute 125K for additional future ducts. **Total ECGP contribution~ $875K**	**$0**	**$125**				
407 Extension - removal of temporary OH Plant 13.8kV & 44kV	407 Relocation - temporary 13.8KV & 44KV pole line removals		**$55**				
407 Phase 2 - Harmony to East City Limits (2016 Project.. Possibly into 2017?)	Potential 2016 project as part of Phase 2 Hwy 407 extension. OPUCN Estimate based on ECGP's very preliminary design			**$300**			
	NET TOTAL 407	**$430**	**$930**	**$300**			

DURHAM REGION Road Widening /Street Extensions- Various Locations (approx 26% contribution -As per the Public Service Works on Highways Act, both City and Region contribute 50% of labour & labour savings devices for OPUCN's work.) NON DISCRETIONARY							
Region Relocate Simcoe St North & Conlin Intersection	Approx 8 -10 new 70ft poles , 44kV and 13.8kV 3 phase primary. Simcoe component completed in 2013. Region and City changed their plans for Conlin but did not confirm their designs in 2014 to proceed with changes, hence carried over into 2014	**$150**					
Region Relocate - Winchester/Harmony Intersection	Approx 18 poles with 810 meters, 13.8 kv, 3 phase lines.	**$100**	**$200**				
Region Relocate - Harmony Rd N -Coldstream to Taunton Rd N - **carried over from 2014**	Approx 600m. Will impact six (6) 13.8kV MS15 Feeder Dips and two (2) 44kV Station Dips.	**$0**	**$480**				
Region Relocate - Harmony Rd N -Rossland to Taunton Rd N	Approx 2,100m. Approx Total Cost - $930K (depending on poles determined to be in conflict.) Region design still not finalized		**$654**				
Region Relocate - Gibb St -East of Stevenson Rd to Simcoe St S	approx 20 poles, 1100 m 13.8KV, 44kV and associated lines. Waiting final design from Region			**$400**			
Region Relocate - Victoria / Bloor St. - West City limits (Thornton) to Stevenson Intersection	Widen from 2/3 lanes to 5 lanes . Pending Region design to verify scope Approx 15-18 poles 800m to 1000 m lines			**$300**			
Region relocate - Gibb St/ Olive Ave Interconnection from Simcoe St to Ritson Rd	Construct new road and Road wideneing - from 2/3 lanes To 4/5 Lanes - Approximately 12 poles pending region final design				**$210**		
Region relocate - Manning Ave / Adelaide Ave - Garrard Rd to Thornton	Construct new roads to 3 lanes and new crossing Approx 6-8 poles. Pending final region design				**$120**		
Region relocate - Thornton Rd from Champlain Ave to King	Road widening to 3/4 lanes - approx 23-25 poles pending region final Region design				**$470**		
Region Relocate - Stevenson Rd - CPR Belleville to Bond St	Road widening from 4 to 5 lanes - approx 20 - 23 poles. Pending final region design					**$400**	
Region Relocate - Rossland Rd - Ritson Rd to Harmony Rd	Road widening to 5 lanes - approx 20-23 poles . Pending Final Region design					**$400**	
Region Relocate - Rossland Rd from Harmony Rd East to Townline Rd	Construct new alignment to 3 lanes including new bridge crossing at Harmony - approx 18 poles. Pending final region design						**$320**
Region relocate - Bloor St, Harmony Rd to Grandview	Road widening approx 20-25 poles. Pending final design from Region						**$480**
MISCELLANEOUS REGION PROJECTS UNDER MATERIAL THRESHOLD		**$0**	**$35**				
	NET TOTAL REGION	**$250**	**$1,369**	**$700**	**$800**	**$800**	**$800**

City of Oshawa - Road Widening/Services - Various Locations (approx 26% contribution - As per the Public Service Works on Highways Act, both City and Region contribute 50% of labour and labour savings devices for OPUCN's work.) NON DISCRETIONAY							
City Relocate - Conlin Rd & Stevenson Rd Intersection **Carried over from 2014 as City will complete their work by Dec 2014**	Approx 7 poles -Waiting for City to firm up design. Approx Total Cost - $150K, City to Pay $45K. Net $105K	$50	$105				
City Relocate - Conlin Rd - East of Stevenson Rd to Founders Dr. **Carried over from 2014 as City will complete their work by Dec 2014**	Approx 15 poles. Approx Total Cost - $200K, City to Pay $50K. Net $150K	$80	$150				
City Relocate - Riverside Dr South - Hoskin Ave to Palace St	Approx 7 poles to be rebuild. Gross approx $135K - Pending City final design		$80				
City Relocation - Gibb St - East of Stevenson Rd to Park Rd - North and south sides	Pending City design - approximately 16 poles gross approx $315K			$190			
City Relocate - Hibbert Ave - East along Cubert	Approx 7 poles to be rebuild. Pending final design - Gross approx $135K			$80			
City Relocate - Sinclair Ave - west of Cubert	Approx 8 poles to be rebuild. Pending final design. Gross approx $150K			$90			
City relocate - Herbert Ave, Eastwood Ave to Carswell Ave	Relocate approx 6-8 poles. Pending Final design Gross approx $150K			$90			
City relocate - Bloor St Realignment (Phase 1)	Relocate approx 14 -16 poles. Pending Final design. Gross approx $450K				$260		
City relocate - Cubert Street, Bloor St to College Ave	Relocate approx 6-8 poles. Pending final design. Gross approx $150K				$90		
City Relocation - Bloor St Realignment (Phase 2)	Relocate approx 10 -12 poles. Pending final design. Gross approx. $350K					$210	
City Relocation - Wilson Rd South - King St to Athol St (West side)	Rebuilld approx 8 poles. Pending final design. Gross approx $200K						$120
City Relocation - Simcoe St North - Colbourne St to Brock St	Rebuilld approx 11 poles. Pending final design. Gross approx $270K						$160
MISCELLANEOUS CITY PROJECTS UNDER MATERIAL THRESHOLD		$172	$170			$140	$70
	NET TOTAL CITY	**$302**	**$505**	**$450**	**$350**	**$350**	**$350**
	TOTAL SYSTEM ACCESS (NET)	**$2,307**	**$4,084**	**$2,685**	**$2,475**	**$2,340**	**$2,350**

SYSTEM RENEWAL							
OH PLANT REBUILDS - Assets at EOL, Failure Risks, legacy standards, obsolete, Reliability impacts							
Wilson - Wentworth To Bloor	Reliability Aged OH Plant > 40 yrs 20 wood poles 1 cct 44Kv 1 cct 13.8kv 900m Includes RR improvements	**$535**					
Adelaide St E - Wilson to Harmony - OH Rebuild	Reliability Aged OH Plant 900m, 22 Poles, 4 Tx, one 13.8kV 3 phase cct	**$400**					
Olive Ave - OH Rebuild - resulting from Dec 2013 Ice storm (new)	Reliability - Aged plant >40 yrs Approx 10 poles, single phase 13.8kV primary	**$120**					
Porcelain switch replacement Program as per ACA	Replace approx 2500 Switches based on Plant inspection by crews - Phase 2	**$150**					
Porcelain insulator replacement Program as per ACA	Replace approx 1200 insulators based on Plant inspection by crews - Phase 2	**$200**					
Wilson TS - HONI's ROW - Rear Lot 44 KV distribution Plant Upgrade. In Nov 2013, HONI claimed they do not own ROWand backed away from pursuing customers to remove encumberances Wooden Poles to be replaced by Dec 2104. Concrete poles okay as per visual inspections	Replace approx 20 poles - pole for pole changeout on most of it. 6-44KV primary feeders leaving Wilson TS going west along HONI's Right of Way, with 2 feeders going south on HONI poles (joint use). 90Deg corners designed for anchor lead lengths.	**$350**					
Simcoe St N Rossland to William - OH Rebuild *Project carried over to 2014*	Work not completed due to service connections and storm. Variance sheet approved for additional cost due to the installation of a 44kV 3phase primary circuit as Back Up redundacy to the Lakeridge Hospital	**$280**					
Park Rd Wenthworth To Stone including Lakefields/Beaupre/ Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside/Lakemount/ Evangeline/Montieth/Bala	Reliability aged OH Plant legacy installation 50+ yrs, 180 (45ft) poles, 7400m single phase 8kV #6 cu primary lines with 35 transformers, porcelain insulators		**$1,300**				
Keewatin (Melrose, Applegrove, Oriole, Willowdale, Springdale)	Reliability aged OH Plant legacy installation, 40+ yrs, #6 cu & 2/0 cu, 3 phase 13.8kV and 8kV single phase primary, 2000 m, 41 (45ft & 50ft) poles 24 Tx		**$745**				
Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary	Reliability aged OH Plant- Acess Issues - Two Laneways - 40+yrs, 8kV #1/0 cu, single phase Total1650 meters, 35 (35ft) poles and associated equipment . Relocate primary and 12 Transformers to roadway;		**$365**				
Rossland - Ritson to Wilson	Reliability aged OH Plant - 40+ yrs, 900 m, 3 phase 44kV and 13.8kV, 24 (65ft & 70ft) poles, 3TX and associated equipment			**$550**			
Athabasca (Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield)	Reliability aged OH plant legacy installation, 40+ yrs, 650m 13.8 kV 14 (50ft) poles and 2000m #6 cu 8 kV 40 (45ft) poles			**$835**			
Eastlawn,Winter,Mackenzie,Labrador	Reliability aged OH plant - 40+ yrs,1250 m 8kV, #6cu, 25 (45ft) poles, 6TX and associated plant			**$360**			
Bloor St - Oliver to MS11	Reliability Aged OH Plant - 40+ yrs,12 (70ft & 75ft) poles, 600m 44kV double circuits and 2 circuits of 13.8kV, 3 UG dips at Station,			**$510**			
Central Park blvd N - Brentwood, Homewood to Harwood	Reliability Aged OH Plant - 40+ yrs, 2000 m single phase 44kV and 13.8kV #6 cu, 44 (45ft & 50ft) poles and associated plant				**$575**		
Landsdowne - Dover, Digby, Surrey, Sussex	Reliability aged OH plant- 40+ yrs, 1300 m 8kV, #6 cu, 28 (45ft) poles, 8TX and associated equipment				**$335**		
Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct	Reliability aged OH Plant - 40+ yrs, 1600 m 8kV, #6 cu, 45 (45ft) poles, 12TX and associated equipment				**$480**		
Rebuild Fisher St, Albert S, Avenue St & Quebec St	Reliability Aged OH Plant - 40+ yrs 15 (50ft) poles 700m 8kV #6 primary, 5TX				**$250**		
GrenFell South of Gibb, Marland, Montrave	Reliability Aged OH Plant - 40+ yrs, 550 m 13.8kV & 8kV, #6cu, 22 poles, 4TX and associated equipment				**$215**		
Julianna & Bernhard	Reliability Aged OH Plant - 40+ yrs, 855m 8kV, #6 cu, 24 (45ft) poles and associated equipment					**$335**	

Mary -Rossland to Aberdeen	OH Rebuild - 40+ yrs,1000 m, 1 phase 8kV, #6 cu, 5 TX, 26 (45ft) poles and associated equipment					**$340**	
Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle	Reliability Aged OH Plant - 40+ yrs, - 2200 m 1 phase 8kV, #6 cu, 55 (45ft) poles, 17 TX and associated plant					**$665**	
Riverside South - Palace and Hosein	Reliability Aged OH Plant- 40+ yrs, 1000 m 1 phase 8kV #6 cu, 26 (45ft) poles, 4TX, and associated plant					**$340**	
Riverside North - Regent, EastHaven, EastGrove, Eastdale, Eastborne, EastGlen, Florian Crt	OH rebuild - 40+ yrs, 2350 m 1 phase 8kV, 58 (45ft) poles, 15 TX and associated plant					**$630**	
King St E 10F1 (Keewatin to Townline)	Reliability Aged OH Plant - 40+yrs, 1000 m,1/0 cu, 21 (55ft) poles, 3phase, 13.8KV, porcelain insulators						**500**
Vimy Ave, Lasalle Ave - OH Rebuild	Reliability Aged OH Plant - 40+ yrs, 500 m 8kV, #6 cu, 12 poles, 4 TX and associated equipment						**175**
Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham	Reliability Aged OH Plant - 55+ yrs, 4550 m 8kV, #6 cu, 120 (45ft & 50ft) poles, 35 TX and associated equipment						**1042**
Grandview, Beaufort and Newbury	OH Rebuild - 40+ yrs,600 m 8kV, #6 cu, 15 (45ft) poles, 3 TX and associated equipment						**200**
Pole Replacement Program (based on Pole testing & inspection)	Replaced poles deemed to be in critical or poor condition identiifed by testing			**$200**	**$200**	**$200**	**200**
OH MISCELLANEOUS PROJECTS UNDER MATERIAL THRESHOLD		**$628**					
	TOTAL OH PLANT REBUILDS	**$2,663**	**$2,410**	**$2,455**	**$2,055**	**$2,510**	**$2,117**

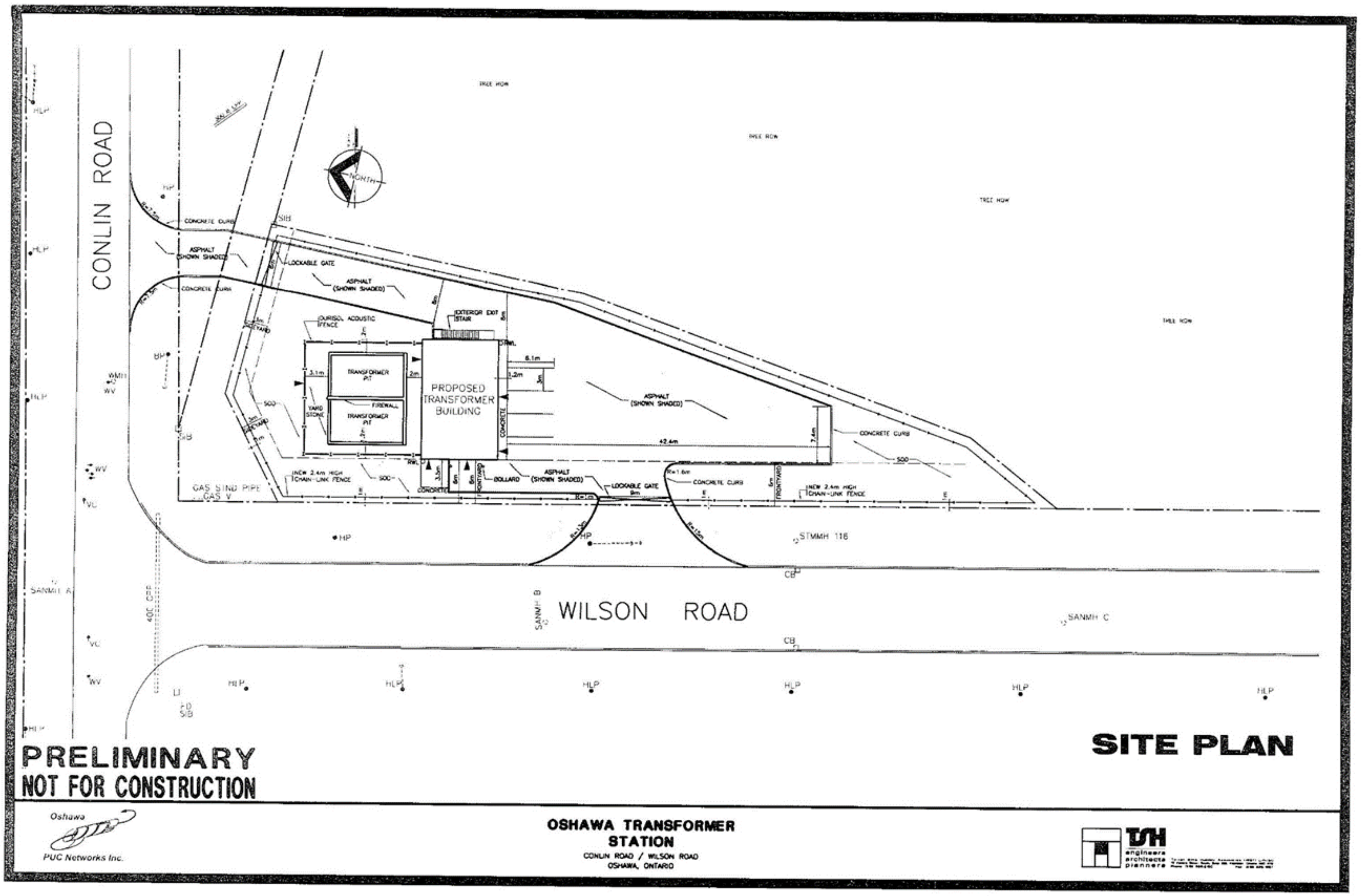
UGPLANT REBUILDS - Assets at EOL, High Failure Risks, legacy standards, obsolete, Reliability impacts							
Rideau St and Anderson Ave- Townhouse complex UG Cable Replacement	Reliability - Aged UG Cable replacement >40 yrs 1600m, single phase primary, town homes, 9 transformers, dip poles	**$204**					
MS13 OH/UG Plant upgrade- 13.8kV/44kV structures (poles) and dips outside MS13 *Westmore Contractor for OH (project carried over to 2014)*	85% completed in 2013 due to service connection work and ice storm. Carry Over to 2014.	**$76**					
Rebuild Londonderry Stm Castlebar Cres, Kilkenny Ct, Cavan Ct, Arklow Ave	Reliability - Aged UG Cable > 40 yrs 1600m, 3 phase #2 cu primary, 12 txs, 2 risers - *UG cable installed in 2013- Final connections to complete*	**$120**					
UG Rebuild Sorrento Ave, Homestead Ct, Cooper Ct,Siena Ct and Salerno St. **Carried over from 2014. City working on clearance issues**	Reliability - Aged UG Cable replacement 40+ yrs 1200m, single phase #2 cu primary, 9 transformers terminations dip poles	**$25**	**$150**				
UG Rebuild - Southgate dr, Southdale Ave, Southdown Dr, Southridge St Subdivision. **Carried over from 2014. City still working on field clearances**	Reliability - Aged 40+ yrs, UG Cable replacement 1150m, single phase#2 cu primary, town homes, 6 transformers Terminations dip poles	**$45**	**$140**				
7 William St - Downtown UG Below Grade Vault	Reliability - Biddle Report - vault not structurally sound. Vault to be rebuilt and VacPAk Switches replaced with remote operated switches	**$400**					
MS 14 13.8kV Feeder lead cable replacement (pot heads leaking).	Reliability - Replace Aged feeder cables> 40yrs at station yard new duct bank 3 new feeder, UG risers poles	**$500**					
Down Crescent, Delmark Ct Townhouse complex	Reliability - Aged 40+ yrs, UG #2 primary cable replacement, 900 m single phase, dip poles (11 Txs Terminations)		**$130**				
Camelot Dr, Merlin Ct, Percival Ct, Lancelot Cres Subdivision	Relaibility Aged 40+ yrs, UG #2 cu primary cable replacement, 1850 m single phase, dip poles (14 Txs Terminations)		**$250**				
Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave	Reliability Aged cable 1973 - cable breakdown with Multiple faults within last 2 years - 2000m, 16tx - Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave, Wecker Dr. .		**$260**				
NorthDale Ave,Mohawk St, BeatriceW, Townhouse complex	Reliability Aged UG #2 cu primary cable replacement > 40 yrs, 1200 m single phase, dip poles (6 Txs)			**$147**			
1100 Oxford St Townhouse Complex	Reliability - Aged UG #2 cu primary cable replacement > 40 yrs, 900 m single phase, dip poles (7 Txs)			**$126**			
Athabasca St, Suton Ct, TownHouse complex	Reliability Aged 40+ yrs UG #2 cu primary cable replacement, 1000 m single phase, dip poles (10 Txs)			**$138**			
MS10 - 10F1 & 10F6 Lead cable & lead potheads replacements	Lead cable replacement, lead potheads. 13.8KV UG Feeder to riser poles inside station yard			**$180**			
Aruba Cres, Aruba St, Waverly St N,Bermuda Ave, Antigua Cres	1973 - 2600m, 15tx - Aruba Cres, Aruba St, Waverly St N, Bermuda Ave, Antigua Cres, Barbados St. Fault locating was lengthy and restoration efforts longer than anticipated due to age of cable.			**$338**			

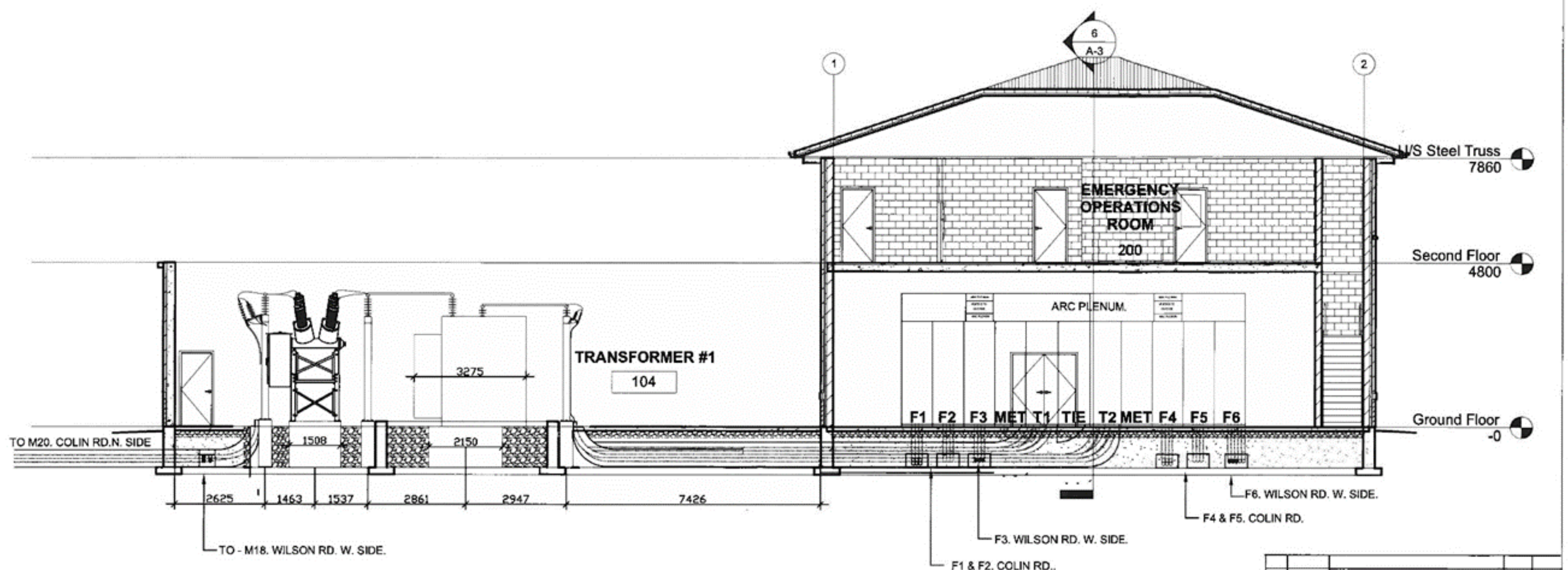
1010 Glen St Townhouse complex	Reliability aged UG 40+ yrs, UG #2 cu primary cable replacement, 1000 m single phase, Townhomes, dip poles (connections to 9 Txs)				$160		
Annandale St, Capilano Cres and Capiland Crt Subdivision	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1100 m single phase, dip poles (9 Txs)				$170		
CherryDown Dr & Sunnybrae Dr Townhouse	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1000 m single phase, dip poles (14Txs)				$185		
Birkdale St. Muirfield St Pinehurst to Subbingham Subdivision	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1500 m single phase, dip poles (8Txs)				$195		
Gladfern, Galahad, Gentry, Gaylord Subdivision	Reliability - Aged 38+ yrs, UG #2 primary cable replacement 2800 m single/three phase (30 Tx)					$405	
Traddles, Dickens Wickham Subdivision	Reliability aged 38+ yrs,UG #2 primary cable replacement 2200m single phase (22 Tx)					$321	
Outlet Dr - Birchcliffe Ct, Lakeview Park Ave & Valley Dr Townhouse complex	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, 1500 m single phase, dip poles (17Txs)					$195	
Marwood Dr Townhouse complex	Reliability Aged 39+ yrs, UG #2 cu primary cable replacement, 850 m three phase, dip poles (5 Txs)						290
Central Park Blvd North, Exeter St and Trowbridge	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, Townhomes, 2000 m single phase, dip poles (12Txs) includes Townhomes Complex 1055 Central Park Blvd N						256
Ormond Dr, EverGlades, Palmetto,Pompano Ct	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, 1800 m single phase, dip poles (8 Txs)						234
Beaufort Court	There is OH Rebuild at Beaufort Ave. This include the UG piece at Beaufort Crt. 1976 - 950m, 5 tx, 1 splice - Beaufort Crt, Cleta Crt, Cherry Crt, Conifer Crt						124
UG MISCELLANEOUS PROJECTS UNDER MATERIAL THRESHOLD		**$80**	**$203**	**$78**	**$377**		
	TOTAL UG PLANT REBUILDS	**$1,450**	**$1,133**	**$1,007**	**$1,087**	**$921**	**$904**

STATIONS REBUILDS - Assets at EOL, Failure Risks, legacy standards, obsolete, Reliability impacts							
Substation Breaker Replacement Program (2011-2016)	Replace Main Vacuum Breakers with SF6 FPE DST2 Main and Westinghouse bus tie - Replace legacy installations with Improve technology	**$175**	**$210**	**$140**			
MS5 T1- Replace 25kVA Power Transformer including Oil Containment -TX out of service - disolved gas results critically high	Replace Power transformer 40+ yrs, with new 25kVA Tx unit c/w Oil Containment - Unit presently out of service	**$840**					
MS14 - Metalclad Switchgear - accelerated corosion -	Relaibility Replace outdoor switchgear, reached end of life Replace with Arc Flash resistance type		**$300**				
MS5 T2- Replace 25kVA Power Transformer including Oil Containment	Unit 30 yrs - Identified needed replacemnent as in poor condition based on tests - approaching end of life - Reliability						**$1,000**
44kV oil circuit breakers replace with SF6 in Outdoor enclosure. Start in 2016 with 4 breakers per year.	Obsolete, end of life 45+ years breaker counter defective - total 12 OCB in the system to be replaced			**$500**	**$500**	**$500**	
	TOTAL STATION REBUILDS	**$1,015**	**$510**	**$640**	**$500**	**$500**	**$1,000**
REACTIVE EMERGENCY CAPITAL							
Replace Underground Transformers	unplanned /emergency replacements	**$220**	**$220**	**$220**	**$220**	**$220**	**$220**
Distribution (OH/UG) Component Changeouts	unplanned /emergency replacements	**$110**	**$110**	**$110**	**$110**	**$110**	**$110**
U/G Secondary Cable Unplanned Replacement	unplanned /emergency replacements	**$180**	**$180**	**$180**	**$180**	**$180**	**$180**
Various OH & UG Reactive or Emergency replacements - poles, lines, cables, Tx, switches, (under material threshold)	unplanned /emergency replacements	**$320**	**$320**	**$320**	**$320**	**$320**	**$320**
	TOTAL REACTIVE EMERGENCY Replacements	**$830**	**$830**	**$830**	**$830**	**$830**	**$830**
	TOTAL SYSTEM RENEWAL	**$5,958**	**$4,883**	**$4,932**	**$4,472**	**$4,761**	**$4,851**

SYSTEM SERVICE							
Wilson TS to Thornton TS Load Transfer (Phase 2) - MS11 - OH Plant rearrngement	Reconfigure Thornton feeders and necessary switches as part of System Load Transfer - This will shift approx 3 MVA from 52M3 to 52M2	**$140**					
Wilson TS to Thornton TS Load Transfer (Phase 2) - Gibb St - Stevenson to MS14	Upgrade from single 44kV circuit to 44kV double circuit along Gibb St to MS 14 (approx 2,200m)	**$1,350**					
Thornton TS - System Capacity - *Riggs Distler Contractor* *Project carried over to 2014*	Turn key Design and Build. Issues with Intersection delayed work. Working with Region to arrive at solution. 70% completed and carried over to 2014	**$362**					
15F1 Extension - Harmony Rd, from Coldstream Dr to Conlin Rd East; Conlin Rd East to Townline (tied to C12-209 Region project completion) *Westmore contractor (Project be carried over to 2014)*	Westmore awarded construction contract $175K.. Approx 80% of project will be completed this year. City rescinded approval on Oct 4 as they have decided to construct a new water main (dropping 10 ft below road surface) along Conlin in 2014. That component of project approx 20% will now be carried over to 2014	**$78**					
Regional Planning - Address Transmission Capacity at **Thornton TS** - Oshawa Requirement for 2 feeders & bus upgrade…	Hydro One (as of Aug 23, 2013) proposes replacement and upgrades of the end of life Power Transformer units. Expected completion before end of 2015. HONI requires Contribution for feeders and associated bus and transmission line upgrades to allow use of capacity. Oshawa requires 2-44kV primary feeders at Thornton. Discussions with HONI and Whitby for solutions are still in progess.		**$1,500**	**$1,500**			
Regional Planning - Address Transmission Capacity at **Wilson TS** - Subject to final Outcomes of Regional Planning discussions which starts in Sept 2013	System Capacity: address needs and customer value - Significant Load Growth in North Oshawa due to 407 expansion and attracting new commercial/industrial customers to Oshawa. On going discussions with HONI . Estimated contribution based on HONI proposa/estimate for 2 new feeder positions in 2019-20				**$1,000**	**$1,000**	**1500**
Distribution Capacity - Construct new **MS 9** - 13.8kV Substation to address load growth in North Oshawa compounded by the extension of 407	System Capacity constraints - customer value - Significant Load Growth in North Oshawa due to 407 expansion and attracting new residential and commercial/industrial customers to Oshawa. Require Station and feeder capacity by 2019		**$750**	**$1,000**	**$3,250**	**$2,000**	
Proposed OH Plant due to new MS9	New 13.8KV distribition feeders to service north Oshawa as per forecasted loads					**$1,000**	**1000**
UG Distribution Automation Project - Phase 1 - Downtown Vaults Automation (including Bell Vault) from 2013 [*Grid Modernization - UtiliWorks Smart Grid roadmap*]	Remote 8 UG automated switches, fibre for communications and control, all tied into SCADA (Total Phase 1 project estimate approx $650K not completed; $400K carried over)	**$400**					
UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (Avanti, Carriage House, Michael Starr, CIBC, PHI Office, William Vaults) *[Grid Modernization - UtiliWorks Smart Grid roadmap*]	Remote 6 UG automated switches, fibre for communications and control, all tied into SCADA	**$500**					
UG Distribution Automation Project - Phase 2 - Downtown Vaults Automation (CIBC Vault and Michael Starr) **Carried over from 2014** *[Grid Modernization - UtiliWorks Smart Grid roadmap* **]**	Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching		**$110**				
UG Distribution Automation Project - Phase 3 - Downtown Vaults Automation (Durham Tower, Bond Towers McLaughlin Square Vaults) *[Grid Modernization - UtiliWorks Smart Grid roadmap]*	Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching		**$438**				

UG Distribution Automation Downtown vaults Phase 4 - Self Healing sytem using remote automated switching and intelligent software application *[Grid Modernization - UtiliWorks Smart Grid roadmap*]	Self Healing UG grid - Modernize and install automation to reduce restoration time, minimize outage duration and Improve Reliability in Downtown core through remote intelligent devices and switching			**$280**	**$10**	**$10**	**10**
OH Distribution Automation Self Healing Intellirupters switches (8 feeders 13 switches over 3 years - 5 switches in phase 1 & 2 with 3 in Phase 3. *[Grid Modernization - UtiliWorks Smart Grid roadmap]*	Self Healing OH grid - Continue with installation of self healing Intellirupters switches for Overhead automation to reduce restoration time, minimize outage duration and Improve Reliability through remote intelligent devices and switching				**$350**	**$350**	**255**
Voltage Monitoring (Volt Var Optimization and Reduction in Distribution Losses) *[UtiliWorks SmartGrid Report Pg 11]*	Voltage communication devices, substation controls and management system (Volt var Optimization					**$225**	**225**
Grid Modernization/Smart Grid related MISI Projects UNDER MATERIAL THRESHOLD *[Utiliworks Smart Grid Report]*	Smart fault indicators and Transmission management system (mitigate system peak loads)		**$70**	**$50**	**$60**	**$60**	**60**
	TOTAL SYSTEM SERVICE	**$2,830**	**$2,868**	**$2,830**	**$4,670**	**$4,645**	**$3,050**
GENERAL PLANT							
Outage Management System (OMS fully integrated with SCADA, GIS, AMI, CIS, IVR) **Phase 1 carried over from 2014**.	Need to proactively provide timely updated communication to customer on outage status. Remotely operate switching, identify outage areas and reduce overall restoration time and outage duration through faster fault identification and automated data mgmt	**$75**	**$850**				
Mobil Work Force - will focus on having OMS fully operational before moving into MWF	leverage automated dispatch for crews assignment of work	**$0**		**$50**	**$50**		
Operational Data Storage (ODS) Replacement	existing ODS no longer able to provide Operational effectiveness. Needs to be replaced			**$400**			
Operational Capital Projects (GIS & MAS/ODS enhancements) individual projects **UNDER Material Threshold**	Ongoing enhancements in MAS/AMI, GIS/OMS/ODS	**$170**		**$85**	**$85**	**$160**	**160**
FLEET Vehicle- 83ft double bucket damaged in 2014 and replaced	Unplanned replacement of Truck 6 due to fire & breakdown. 2014 inlcudes delivery of chasis and in 2015 will include full truck delivery with body and boom ($370K less $100K tradein = $270K in 2015)	**$100**	**$270**				
FLEET Vehicle- 46ft single Bucket one in 2016 & 2017	Replace two vehicles, each approaching end of life			**$375**	**$375**		
FLEET - Individual **vehicles UNDER MATERIAL THRESHOLD**	smaller vehicle purchases to minimize fuel intake and operations	**$55**	**$150**	**$40**	**$65**	**$190**	**170**
Facilities - Refurbish & rearrange floorplan of Customer service area and Finance area to improve operational efficiencies	current floorplan of CSR work stations and Finance area is causing disruptions to the day to day function. Need better and effective layout	**$0**					
Renovate Tech area for additional work station and washroom (100K 2015) plus pole yard storage $75K for material Cable reels space to be cleared for vehicle space	Reaarrange floor plan to create 2 additional work station/area and parking spaces in parking lot		**$175**				
Servers Upgrades in Production and DRP - End of Life in 2018. No longer supprted. Originally installed end 2012	Servers currently for production environment and DRP operations will reach end of life in 2018. No longer supported. Originally installed in end of 2012 Full replacement required for all business application and operations					**$200**	
MISCELLANEOUS PROJECTS **(Major Tools, Minor Leasehold improvements) UNDER MATERIAL THRESHOLD**		**$144**	**$100**	**$100**	**$100**	**$100**	**100**
MISCELLANEOUS Office Capital Expenditure (IT hardware and software Systems) Individual Projects UNDER MATERIAL THRESHOLD		**$90**	**$130**	**$130**	**$80**	**$80**	**80**
	TOTAL GENERAL PLANT	**$634**	**$1,675**	**$1,180**	**$755**	**$730**	**$510**
2014 - 2019 NET TOTAL ANNUAL CAPITAL EXPENDITURES		**$11,729**	**$13,510**	**$11,627**	**$12,372**	**$12,476**	**$10,761**


CONLIN ROAD
NORTH
PROPOSED TRANSFORMER BUILDING
TRANSFORMER PIT
TRANSFORMER PIT
GAS SIND PIPE
GAS V
STMMH 116
WILSON ROAD
SANMH C
PRELIMINARY
NOT FOR CONSTRUCTION
SITE PLAN
Oshawa
PUC Networks Inc.
OSHAWA TRANSFORMER STATION
CONLIN ROAD / WILSON ROAD
OSHAWA, ONTARIO



NOTES:
TRANSFORMER DIMENSIONS ARE APPROXIMATE.

ALL DUCT BANKS ARE CONCRETE ENCASED

FOR BIDDING PURPOSES ONLY NOT FOR CONSTRUCTION

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K-LINE MAINTENANCE & CONSTRUCTION LIMITED
12731 HWY. #48, STOUFFVILLE, ONTARIO, L4A 7X5, PHONE: (905) 640-2002

CUSTOMER: Oshawa PUC Networks Inc.

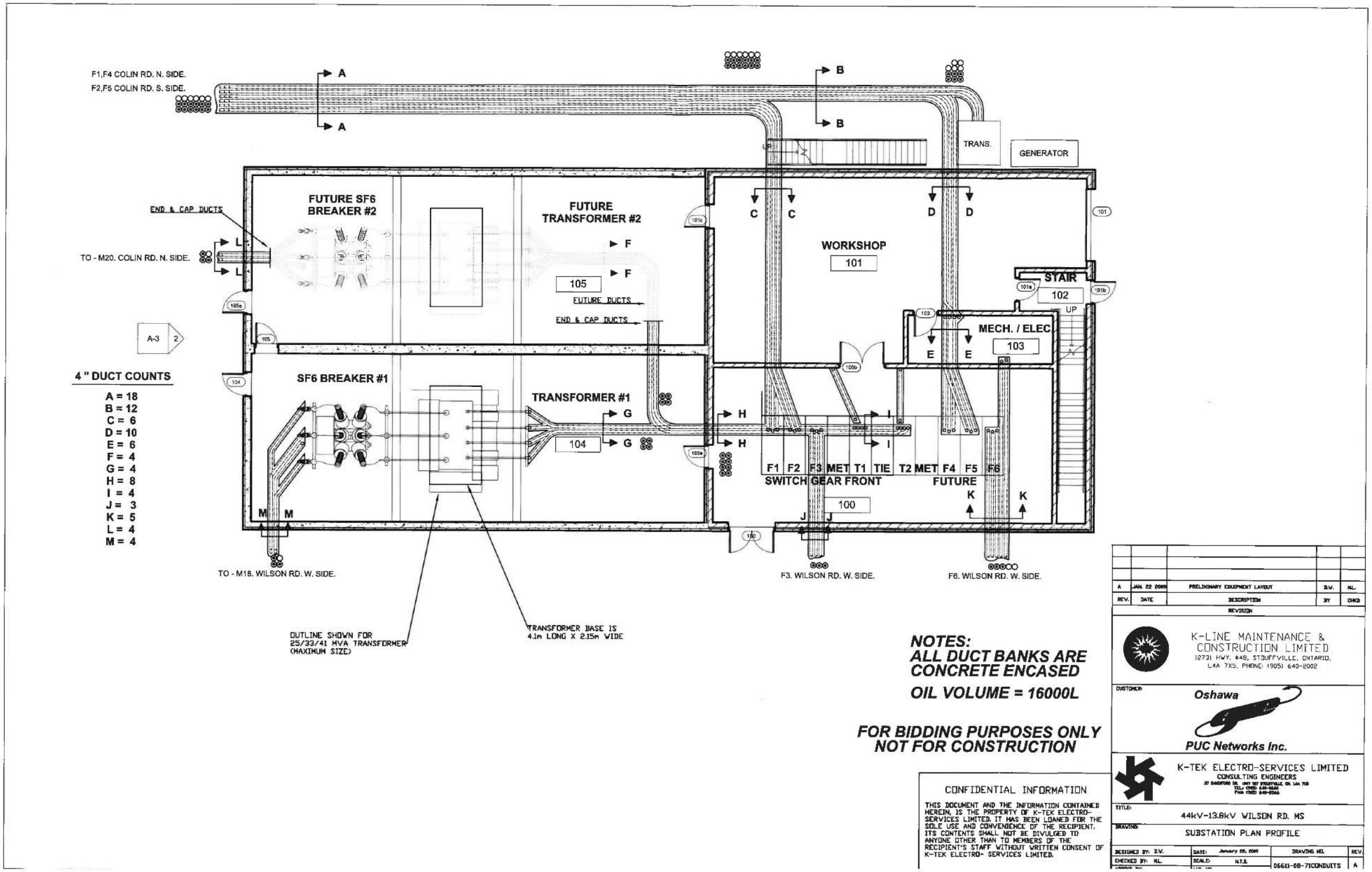
K-TEK ELECTRO-SERVICES LIMITED
CONSULTING ENGINEERS

TITLE: 44kV-13.8kV WILSON RD. MS

DRAWING: SUBSTATION PLAN PROFILE

A	JAN 22 2009	PRELIMINARY EQUIPMENT LAYOUT PROFILE	D.V.	N.L.
REV.	DATE	DESCRIPTION	BY	CHKD

DESIGNED BY: D.V. | DATE: January 22, 2009 | DRAWING NO. 06611-08-71PROFILE | REV. A
CHECKED BY: N.L. | SCALE: N.T.S.


F1,F4 COLIN RD. N. SIDE.
F2,F5 COLIN RD. S. SIDE.
A
B
TRANS.
GENERATOR
END & CAP DUCTS
FUTURE SF6 BREAKER #2
FUTURE TRANSFORMER #2
TO - M20. COLIN RD. N. SIDE.
105
FUTURE DUCTS
END & CAP DUCTS
WORKSHOP
101
STAIR
102
UP
MECH. / ELEC
103
A-3
2
4 " DUCT COUNTS
A = 18
B = 12
C = 6
D = 10
E = 6
F = 4
G = 4
H = 8
I = 4
J = 3
K = 5
L = 4
M = 4
SF6 BREAKER #1
TRANSFORMER #1
104
F1 F2 F3 MET T1 TIE T2 MET F4 F5 F6
SWITCH GEAR FRONT
FUTURE
100
TO - M18. WILSON RD. W. SIDE.
F3. WILSON RD. W. SIDE.
F6. WILSON RD. W. SIDE.
OUTLINE SHOWN FOR 25/33/41 MVA TRANSFORMER (MAXIMUM SIZE)
TRANSFORMER BASE IS 4.1m LONG X 2.15m WIDE
NOTES:
ALL DUCT BANKS ARE CONCRETE ENCASED
OIL VOLUME = 16000L
FOR BIDDING PURPOSES ONLY
NOT FOR CONSTRUCTION
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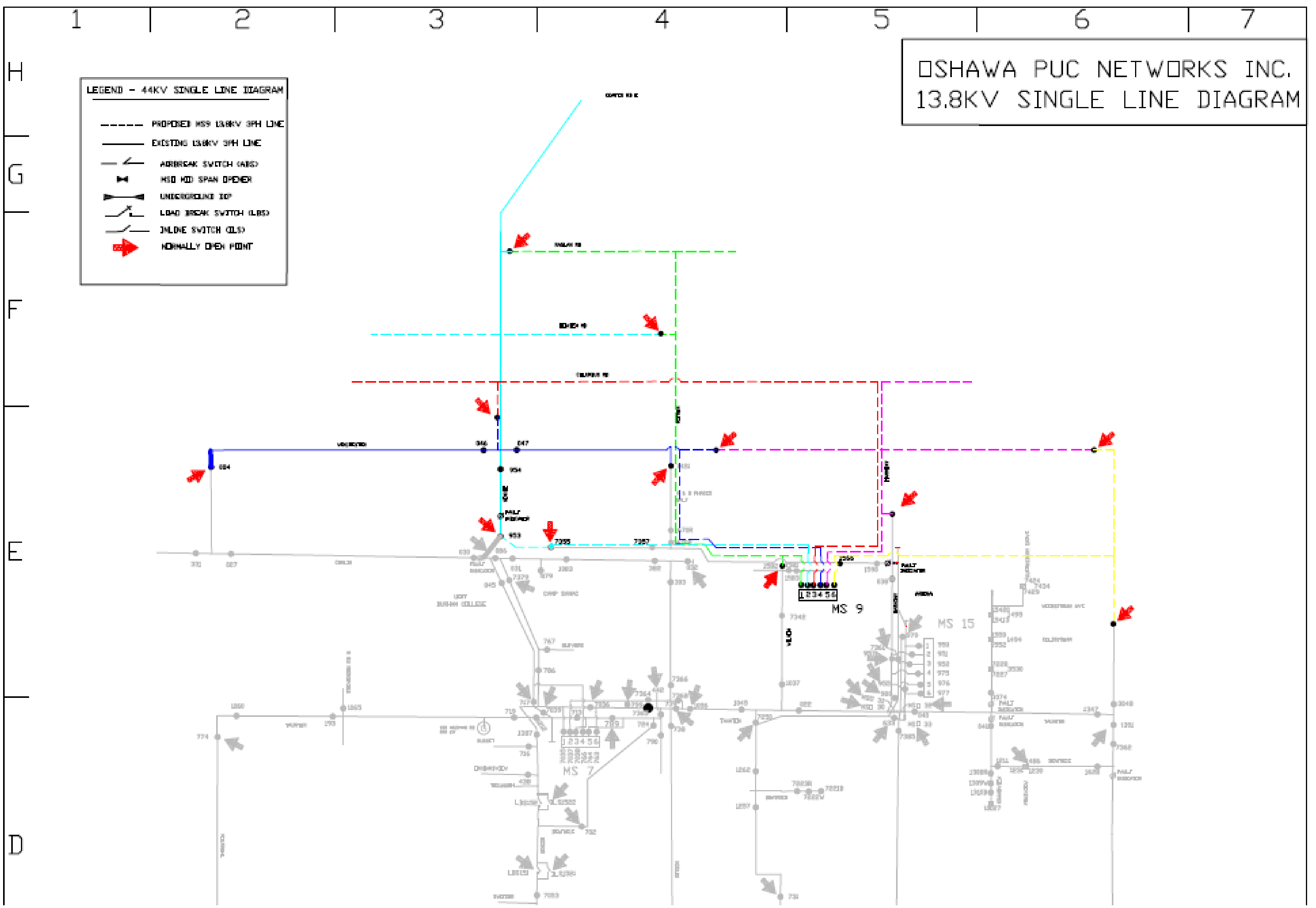
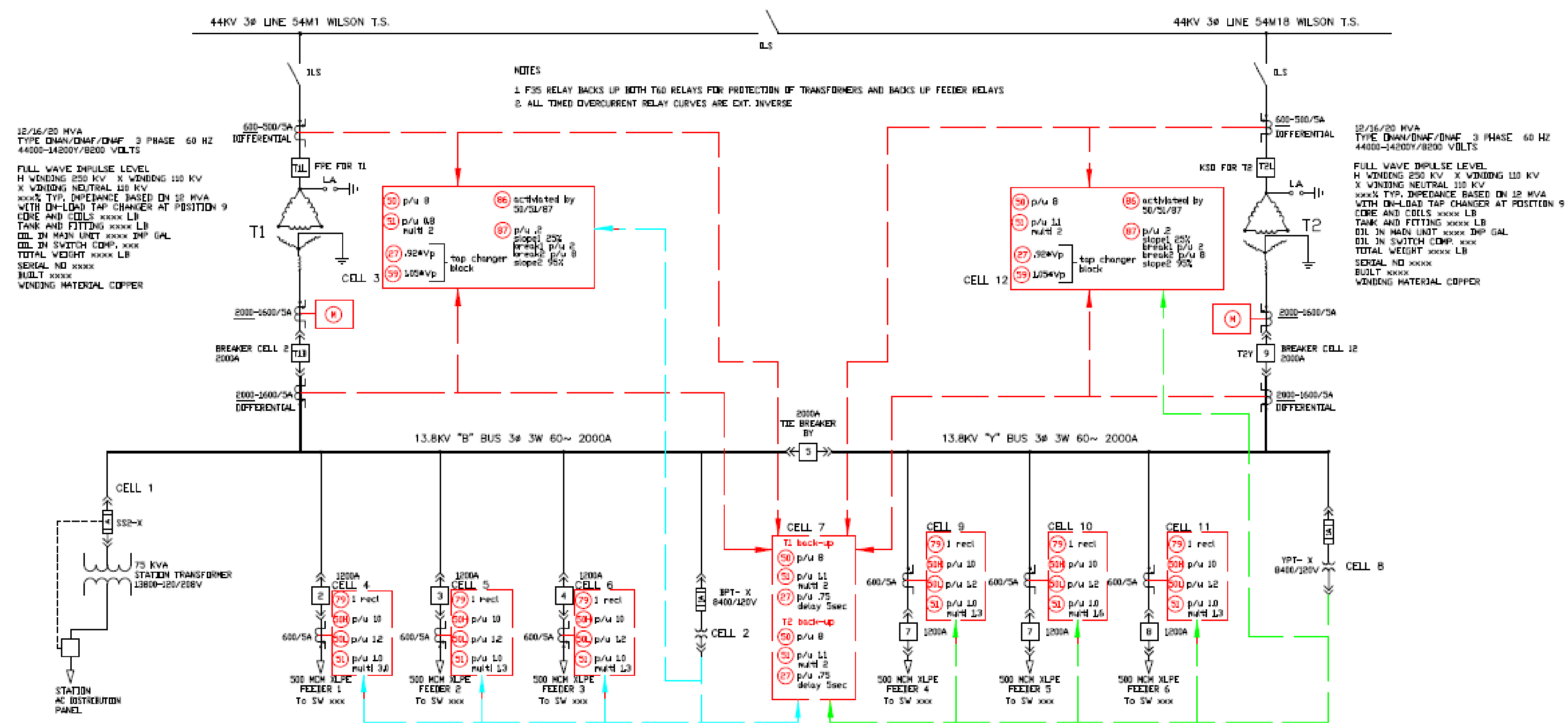
PRELIMINARY EQUIPMENT LAYOUT
REV. DATE DESCRIPTION BY CHKD
REVISION
K-LINE MAINTENANCE & CONSTRUCTION LIMITED
12731 HWY. #48, STOUFFVILLE, ONTARIO, L4A 7X5, PHONE: (905) 640-2002
CUSTOMER:
Oshawa
PUC Networks Inc.
K-TEK ELECTRO-SERVICES LIMITED
CONSULTING ENGINEERS
TITLE:
44kV-13.8kV WILSON RD. MS
DRAWING:
SUBSTATION PLAN PROFILE
DESIGNED BY: J.V.
CHECKED BY: N.L.
SCALE: N.T.S.
DRAWING NO.
REV.
A


OSHAWA PUC NETWORKS INC.
13.8KV SINGLE LINE DIAGRAM
LEGEND - 44KV SINGLE LINE DIAGRAM
PROPOSED MS9 13.8KV 3PH LINE
EXISTING 13.8KV 3PH LINE
AIRBREAK SWITCH (ABS)
MSO MID SPAN OPENER
UNDERGROUND DIP
LOAD BREAK SWITCH (LBS)
INLINE SWITCH (ILS)
NORMALLY OPEN POINT
1
2
3
4
5
6
7
H
G
F
E
D
MS 9
MS 15
MS 7
123456



	PROTECTIVE RELAYING
50	INSTANTANEOUS OVERCURRENT RELAY
51	AC TIMED OVERCURRENT RELAY
87	DIFFERENTIAL
86	LOCKOUT RELAY
27/59	UNDERVOLTAGE/OVERVOLTAGE

	PROTECTIVE RELAY TYPES GE MULTILIN
F35	TIE BREAKER CELL 7
T60	TRANSFORMER CELL 3 & 12
F60	FEEDER CELLS 4,5,6,9,10,11

No.	DATE	BY	APP'D	REMARKS
0	MAR 12 2014			PROPOSED MS9 SLD (NOT FOR CONSTRUCTION)

REVISIONS

OSHAWA PUC NETWORKS INC.

TITLE

PROPOSED MS9 SINGLE LINE DIAGRAM (NOT FOR CONSTRUCTION)

CAD drawing file Directory and name	DATE	STATION	DWG. BY	SHEET No.	REV.
	MAR 2014	MS9		1 OF 1	

407 Related Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional “Miscellaneous Project” category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

The following is the list of 407 Projects:

APPENDIX 'A' - OPUCN CAPITAL EXPENDITURES DETAILS (2014 - 2019)							
2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		**2014 NET**	**2015 NET**	**2016 NET**	**2017 NET**	**2018 NET**	**2019 NET**
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM ACCESS							
HWY 407 Extension - Plant relocation - Various Locations (100% contribution for like for like replacement) - NON DISCRETIONARY							
407 Extension - Winchester & Thornton Intersection - **Carried over from 2014**	Estimated $2 million based on Consultant estimates to relocate existing plant UG. OPUCN to contribute approx 270K for additional future ducts with **ECGP contributing $1,730K**. Total Project ~$2million	**$20**	**$250**				
407 Extension - Winchester & Simcoe Intersection - **Carried over from 2014**	Estimated $960K based on Consultant estimates to relocate existing plant Underground. 407 ECGP willing to pay for OH solution and **contribute $440K** to the project with OPUCN picking up $520K for UG section.	**$20**	**$500**				
407 Extension - Bridle Rd Intersection - To be Completed in 2014	Estimated $220K based on Consultant estimates to install future UG infrastructure for future load development north of 407. OPUCN cost of $220K for additional future ducts.Total Project costs~ $220K	**$220**	**$0**				
407 Extension - Ritson Rd Intersection - **To be Completed in 2014**	Estimated $470K based on Consultant estimates to relocate existing plant UG. OPUCN to contribute $120K for additional future ducts. **ECGP contribution ~ $350K**	**$120**	**$0**				
407 Extension - Wilson Rd Intersection - **Completed in 2014**	Estimated $470K based on Consultant estimates to relocate existing plant UG. OPUCN to contribute $125K for additional future ducts. **ECGP contribution ~ $345K**	**$50**	**$0**				
407 Extension - Harmony Rd Intersection - **carried over from 2014 to 2015**	Estimated $1 million based on Consultant estimates to relocate existing plant UG. OPUCN to contribute 125K for additional future ducts. **Total ECGP contribution~ $875K**	**$0**	**$125**				
407 Extension - removal of temporary OH Plant 13.8kV & 44kV	407 Relocation - temporary 13.8KV & 44KV pole line removals		**$55**				
407 Phase 2 - Harmony to East City Limits (2016 Project.. Possibly into 2017?)	Potential 2016 project as part of Phase 2 Hwy 407 extension. OPUCN Estimate based on ECGP's very preliminary design			**$300**			
	NET TOTAL 407	**$430**	**$930**	**$300**			

<u>2014 Hwy 407 Projects:</u> Total gross expenditure is ~$430 thousand; No ECGP Contribution to be realized in 2014; NET OPUCN expenditure ~ $430 thousand

1) 407 Extension - Winchester & Thornton "clover leaf" Interchange: ECGP Delays in awarding construction contract. 2014 forecast expenditures of approximately $20 thousand related more to design. ***Carried over to 2015***.

2) 407 Extension - Winchester & Simcoe "clover leaf" Interchange: ECGP Delays in awarding construction contract. Forecast expenditures of approximately $20 thousand related more to design. ***Carried over to 2015.***

3) 407 Extension - Harmony Rd. "clover leaf" Interchange – Estimated gross annual expenditure $1.0M; ECGP contribution $875 thousand; OPUCN NET expenditure $125 thousand. ***Carried over to 2015.***

4) 407 Extension - Bridle Rd. Intersection – ECGP proposing overpass that will prohibit any future overhead plant installations. Therefore, OPUCN is requesting ECGP to install UG infrastructure for future load development north of 407. ECGP Contractors will complete construction with OPUCN Contribution of $200 thousand. ***Expect completion in 2014.***

5) 407 Extension - Ritson Rd. Intersection - ECGP proposing overpass that conflicts with overhead plant Estimated gross annual expenditure $470 thousand; ECGP contribution $345 thousand; OPUCN NET expenditure $125 thousand for additional future ducts. ***Expect completion in 2014.***

6) 407 Extension - Wilson Rd. Intersection – ECGP proposing overpass that will prohibit any future overhead plant installations. Therefore, OPUCN is requesting ECGP to install UG infrastructure for future load development north of 407. Estimated gross annual expenditure $470 thousand; ECGP contribution $345 thousand; OPUCN NET expenditure $50 thousand for additional future ducts. ***Expect completion in 2014.***

<u>2015 Hwy 407 Projects:</u> - Total gross expenditure is ~$4.5 million; ECGP Contribution approx. $3.6 million; NET OPUCN expenditure approx. $930 thousand

1) 407 Extension - Winchester & Thornton "clover leaf" Interchange: Estimated gross annual expenditure - $2M; ECGP's contribution is approximately $1.75M; OPUCN NET expenditure is approximately $250 thousand. ***Carried over from 2014.***

2) 407 Extension - Winchester & Simcoe “clover leaf” Interchange: Estimated gross annual expenditure - $960 thousand; ECGP’s contribution is approximately $440 thousand; OPUCN NET expenditure approx. $520 thousand. ***Carried over from 2014.***

3) 407 Extension - Harmony Rd. “clover leaf” Interchange – Estimated gross annual expenditure $1.0 million; ECGP contribution $875 thousand; OPUCN NET expenditure approximately $125 thousand. ***Carried over from 2014.***

4) 407 Extension – Temp Plant removal **–** Temporary 13.8KV & 44KV pole line removals plus miscellaneous carry-over work - Total gross expenditure is ~$550 thousand; ECGP Contribution approx. $495 thousand; NET OPUCN expenditure approximately $55 thousand.

<u>2016 Hwy 407 Projects:</u> Harmony to East City Limits - Part of Phase 2 Hwy 407 extension. OPUCN’s estimate based on ECGP's very preliminary design. ***Total gross expenditure is ~$700 thousand; ECGP Contribution ~$400 thousand; NET OPUCN expenditure ~$300 thousand***

Durham Region Related Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional “Miscellaneous Project” category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

The following is the list of Region Projects over the material threshold:

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
SYSTEM ACCESS							
DURHAM REGION Road Widening /Street Extensions- Various Locations (approx 26% contribution -As per the Public Service Works on Highways Act, both City and Region contribute 50% of labour & labour savings devices for OPUCN's work.)							
Region Relocate Simcoe St North & Conlin Intersection **(carry over from 2013 to 2014)**	Approx 8 -10 new 70ft poles , 44kV and 13.8kV 3 phase primary. Simcoe component completed in 2013. Region and City changed their plans for Conlin but did not confirm their designs in 2014 to proceed with changes, hence carried over into 2014	$150					
Region Relocate - Winchester/Harmony Intersection - **Carried over from 2014**	Approx 18 poles with 810 meters, 13.8 kv, 3 phase lines.	$100	$200				
Region Relocate - Harmony Rd N -Coldstream to Taunton Rd N - **carried over from 2014**	Approx 600m. Will impact six (6) 13.8kV MS15 Feeder Dips and two (2) 44kV Station Dips.	$0	$480				
Region Relocate - Harmony Rd N -Rossland to Taunton Rd N	Approx 2,100m. Approx Total Cost - $930K (depending on poles determined to be in conflict.) Region design still not finalized		$654				
Region Relocate - Gibb St -East of Stevenson Rd to Simcoe St S	approx 20 poles, 1100 m 13.8KV, 44kV and associated lines. Waiting final design from Region			$400			
Region Relocate - Victoria / Bloor St. - West City limits (Thornton) to Stevenson Intersection	Widen from 2/3 lanes to 5 lanes . Pending Region design to verify scope Approx 15-18 poles 800m to 1000 m lines			$300			
Region relocate - Gibb St/ Olive Ave Interconnection from Simcoe St to Ritson Rd	Construct new road and Road wideneing - from 2/3 lanes To 4/5 Lanes - Approximately 12 poles pending region final design				$210		
Region relocate - Manning Ave / Adelaide Ave - Garrard Rd to Thornton	Construct new roads to 3 lanes and new crossing Approx 6-8 poles. Pending final region design				$120		
Region relocate - Thornton Rd from Champlain Ave to King	Road widening to 3/4 lanes - approx 23-25 poles pending region final Region design				$470		
Region Relocate - Stevenson Rd - CPR Belleville to Bond St	Road widening from 4 to 5 lanes - approx 20 - 23 poles. Pending final region design					$400	
Region Relocate - Rossland Rd - Ritson Rd to Harmony Rd	Road widening to 5 lanes - approx 20-23 poles . Pending Final Region design					$400	
Region Relocate - Rossland Rd from Harmony Rd East to Townline Rd	Construct new alignment to 3 lanes including new bridge crossing at Harmony - approx 18 poles. Pending final region design						$320
Region relocate - Bloor St, Harmony Rd to Grandview	Road widening approx 20-25 poles. Pending final design from Region						$480
MISCELLANEOUS REGION PROJECTS UNDER MATERIAL THRESHOLD		$0	$35				
	NET TOTAL REGION	**$250**	**$1,369**	**$700**	**$800**	**$800**	**$800**

***<u>2014 Region Projects</u>*: Total gross expenditure is ~$250 thousand; No Region Contribution; NET OPUCN expenditure ~$250 thousand**

1) Region Relocate Simcoe St. North & Conlin Intersection: Net Estimated expenditure $150 thousand. ***Carried over from 2013.***

2) Region Relocate - Winchester/Harmony Intersection: Net Estimated expenditure $100K. Partially completed due to Region delays. To be completed in 2015.

***<u>2015 Region Projects</u>*: Total gross expenditure is ~$1.9 million; Region Contribution ~$506 thousand; NET OPUCN expenditure ~$1.4 million**

1) Region Relocate - Winchester/Harmony Intersection: Net estimated expenditure $200K. ***Carried over from 2014.***

2) Region Relocate - Harmony Rd. N - Coldstream to Taunton Rd N: Net estimated expenditure $480 thousand.

3) Region Relocate - Harmony Rd. N - Rossland to Taunton Rd N: Net estimated expenditure $654 thousand.

<u>2016 Region Projects:</u> Total gross expenditure is ~$935 thousand; Region Contribution ~$235 thousand; NET OPUCN expenditure ~$700 thousand – pending Region's final design

1) Region Relocate - Gibb St. -East of Stevenson Rd. to Simcoe St. S: Net estimated expenditure $400 thousand.

2) Region Relocate - Victoria/Bloor St. - West City limits (Thornton) to Stevenson Intersection: Net estimated expenditure $300 thousand.

***<u>2017 Region Projects</u>*: Total gross expenditure is ~$1.1 million; Region Contribution ~$265 thousand; NET OPUCN expenditure ~$800 thousand – pending Region's final design**

1) Region Relocate - Region relocate - Gibb St./Olive Ave. Interconnection from Simcoe St. to Ritson Rd.: Net estimated expenditure $210 thousand.

2) Region Relocate - Manning Ave./Adelaide Ave. - Garrard Rd. to Thornton: Net estimated expenditure $120 thousand.

3) Region relocate - Thornton Rd. from Champlain Ave. to King Region relocate: Net estimated expenditure $470 thousand.

<u>2018 Region Projects</u>*: Total gross expenditure is ~$1.1 million; Region Contribution ~$280 thousand; NET OPUCN expenditure ~$800 thousand – pending Region's final design

1) Region Relocate - Stevenson Rd. - CPR Belleville to Bond St: Net estimated expenditure $400 thousand

2) Region Relocate - Rossland Rd. - Ritson Rd. to Harmony Rd.: Net estimated expenditure $400 thousand

<u>2019 Region Projects</u>*: Total gross expenditure is ~$1.1 million; Region Contribution ~$280 thousand; NET OPUCN expenditure ~$800 thousand – pending Region's final design

1) Region Relocate - Rossland Rd. from Harmony Rd. East to Townline Rd.: Estimated Gross expenditure $320 thousand.

2) Region Relocate - Bloor St, Harmony Rd. to Grandview Ave.: Estimated Gross expenditure $480 thousand

City of Oshawa Related Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

The following is the list of City Projects over the material threshold:

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM ACCESS							
City of Oshawa - Road Widening/Services - Various Locations (approx 26% contribution - As per the Public Service Works on Highways Act, both City and Region contribute 50% of labour and labour savings devices for OPUCN's work.) NON DISCRETIONAY							
City Relocate - Conlin Rd & Stevenson Rd Intersection **Carried over from 2014 as City will complete their work by Dec 2014**	Approx 7 poles -Waiting for City to firm up design. Approx Total Cost - $150K, City to Pay $45K. Net $105K	**$50**	**$105**				
City Relocate - Conlin Rd - East of Stevenson Rd to Founders Dr. **Carried over from 2014 as City will complete their work by Dec 2014**	Approx 15 poles. Approx Total Cost - $200K, City to Pay $50K. Net $150K	**$80**	**$150**				
City Relocate - Riverside Dr South - Hoskin Ave to Palace St	Approx 7 poles to be rebuild. Gross approx $135K - Pending City final design		**$80**				
City Relocation - Gibb St - East of Stevenson Rd to Park Rd - North and south sides	Pending City design - approximately 16 poles gross approx $315K			**$190**			
City Relocate - Hibbert Ave - East along Cubert	Approx 7 poles to be rebuild. Pending final design - Gross approx $135K			**$80**			
City Relocate - Sinclair Ave - west of Cubert	Approx 8 poles to be rebuild. Pending final design. Gross approx $150K			**$90**			
City relocate - Herbert Ave, Eastwood Ave to Carswell Ave	Relocate approx 6-8 poles. Pending Final design Gross approx $150K			**$90**			
City relocate - Bloor St Realignment (Phase 1)	Relocate approx 14 -16 poles. Pending Final design. Gross approx $450K				**$260**		
City relocate - Cubert Street, Bloor St to College Ave	Relocate approx 6-8 poles. Pending final design. Gross approx $150K				**$90**		
City Relocation - Bloor St Realignment (Phase 2)	Relocate approx 10 -12 poles. Pending final design. Gross approx. $350K					**$210**	
City Relocation - Wilson Rd South - King St to Athol St (West side)	Rebuilld approx 8 poles. Pending final design. Gross approx $200K						**$120**
City Relocation - Simcoe St North - Colbourne St to Brock St	Rebuilld approx 11 poles. Pending final design. Gross approx $270K						**$160**
MISCELLANEOUS CITY PROJECTS UNDER MATERIAL THRESHOLD		**$172**	**$170**			**$140**	**$70**
	NET TOTAL CITY	**$302**	**$505**	**$450**	**$350**	**$350**	**$350**

<u>2014 City Projects</u>: Total gross expenditure is ~$130 thousand; No City Contribution; NET OPUCN expenditure ~$130 thousand

1) City Relocate - Conlin Rd. & Stevenson Rd. Intersection; Net OPUCN estimated expenditure ~$50 thousand - City delays in design caused work to have a late start. To be carried over to 2015.

2) City Relocate - Conlin Rd. - East of Stevenson Rd to Founders: Net OPUCN estimated expenditure ~$80 thousand - City delays in design caused work to have a late start. To be carried over to 2015.

<u>2015 City Projects</u>: Total gross expenditure is ~$535 thousand; City Contribution ~$200 thousand; NET OPUCN expenditure ~$335 thousand

1) City Relocate - Conlin Rd. & Stevenson Rd. Intersection; Net OPUCN estimated expenditure ~$105 thousand - ***Carried over from 2014.***

2) City Relocate - Conlin Rd. - East of Stevenson Rd. to Founders: Net OPUCN estimated expenditure ~$50 thousand - ***Carried over from 2014.***

3) Riverside Dr. South - Hoskin Ave. to Palace St.: NET OPUCN expenditure ~$80 thousand.

<u>2016 City Projects</u>: Total gross expenditure is ~$750 thousand; City Contribution ~$300 thousand; NET OPUCN expenditure ~$450 thousand - pending final City's design

1) City Relocate - Gibb St. - East of Stevenson Rd. to Park Rd. - North and south sides; Net estimated OPUCN expenditure ~$190 thousand.

2) City Relocate - Hibbert Ave. - East along Cubert: Net estimated OPUCN expenditure ~$80 thousand.

3) City Relocate - Sinclair Ave. - West of Cubert: Net estimated OPUCN expenditure ~$90 thousand.

4) City Relocate - Herbert Ave., Eastwood Ave. to Carswell Ave.: Net estimated OPUCN expenditure ~$90 thousand

<u>2017 City Projects</u>: Total gross expenditure is ~$600 thousand; City Contribution ~$250 thousand; NET OPUCN expenditure ~$350 thousand - pending final City's design

1) City Relocate - Bloor St Realignment (Phase 1); Net estimated OPUCN expenditure ~$260 thousand.

2) City Relocate - Cubert St., Bloor St. to College Ave.: Net estimated OPUCN expenditure ~$90 thousand.

<u>2018 City Project</u>: Bloor St Realignment (Phase 2): Total gross expenditure is ~$350 thousand; City Contribution ~$140 thousand; NET OPUCN expenditure ~$210 thousand - pending final City's design

<u>2019 City Projects</u>: Total gross expenditure is ~$470 thousand; City Contribution ~$190 thousand; NET OPUCN expenditure ~$280 thousand - pending final City's design

1) City Relocate - Wilson Rd. South - King St. to Athol St. (West side): Net estimated OPUCN expenditure ~$120 thousand.

2) City Relocate - Simcoe St North - Colbourne St. to Brock St.: Net estimated OPUCN expenditure ~$160 thousand.

Overhead Rebuild Program Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM RENEWAL							
OH PLANT REBUILDS - Assets at EOL, Failure Risks, legacy standards, obsolete, Reliability impacts							
Wilson - Wentworth To Bloor	Reliability Aged OH Plant > 40 yrs 20 wood poles 1 cct 44Kv 1 cct 13.8kv 900m Includes RR improvements	**$535**					
Adelaide St E - Wilson to Harmony - OH Rebuild	Reliability Aged OH Plant 900m, 22 Poles, 4 Tx, one 13.8kV 3 phase cct	**$400**					
Olive Ave - OH Rebuild - resulting from Dec 2013 Ice storm (new)	Reliability - Aged plant >40 yrs Approx 10 poles, single phase 13.8kV primary	**$120**					
Porcelain switch replacement Program as per ACA	Replace approx 2500 Switches based on Plant inspection by crews - Phase 2	**$150**					
Porcelain insulator replacement Program as per ACA	Replace approx 1200 insulators based on Plant inspection by crews - Phase 2	**$200**					
Wilson TS - HONI's ROW - Rear Lot 44 KV distribution Plant Upgrade. In Nov 2013, HONI claimed they do not own ROWand backed away from pursuing customers to remove encumberances Wooden Poles to be replaced by Dec 2104. Concrete poles okay as per visual inspections	Replace approx 20 poles - pole for pole changeout on most of it. 6-44KV primary feeders leaving Wilson TS going west along HONI's Right of Way, with 2 feeders going south on HONI poles (joint use). 90Deg corners designed for anchor lead lengths.	**$350**					
Simcoe St N Rossland to William - OH Rebuild *Project carried over to 2014*	Work not completed due to service connections and storm. Variance sheet approved for additional cost due to the installation of a 44kV 3phase primary circuit as Back Up redundacy to the Lakeridge Hospital	**$280**					
Park Rd Wenthworth To Stone including Lakefields/Beaupre/ Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside/Lakemount/ Evangeline/Montieth/Bala	Reliability aged OH Plant legacy installation 50+ yrs, 180 (45ft) poles, 7400m single phase 8kV #6 cu primary lines with 35 transformers, porcelain insulators		**$1,300**				
Keewatin (Melrose, Applegrove, Oriole, Willowdale, Springdale)	Reliability aged OH Plant legacy installation, 40+ yrs, #6 cu & 2/0 cu, 3 phase 13.8kV and 8kV single phase primary, 2000 m, 41 (45ft & 50ft) poles 24 Tx		**$745**				
Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary	Reliability aged OH Plant- Acess Issues - Two Laneways - 40+yrs, 8kV #1/0 cu, single phase Total1650 meters, 35 (35ft) poles and associated equipment . Relocate primary and 12 Transformers to roadway;		**$365**				
Rossland - Ritson to Wilson	Reliability aged OH Plant - 40+ yrs, 900 m, 3 phase 44kV and 13.8kV, 24 (65ft & 70ft) poles, 3TX and associated equipment			**$550**			
Athabasca (Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield)	Reliability aged OH plant legacy installation, 40+ yrs, 650m 13.8 kV 14 (50ft) poles and 2000m #6 cu 8 kV 40 (45ft) poles			**$835**			
Eastlawn,Winter,Mackenzie,Labrador	Reliability aged OH plant - 40+ yrs,1250 m 8kV, #6cu, 25 (45ft) poles, 6TX and associated plant			**$360**			
Bloor St - Oliver to MS11	Reliability Aged OH Plant - 40+ yrs,12 (70ft & 75ft) poles, 600m 44kV double circuits and 2 circuits of 13.8kV, 3 UG dips at Station,			**$510**			
Central Park blvd N - Brentwood, Homewood to Harwood	Reliability Aged OH Plant - 40+ yrs, 2000 m single phase 44kV and 13.8kV #6 cu, 44 (45ft & 50ft) poles and associated plant				**$575**		
Landsdowne - Dover, Digby, Surrey, Sussex	Reliability aged OH plant- 40+ yrs, 1300 m 8kV, #6 cu, 28 (45ft) poles, 8TX and associated equipment				**$335**		
Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct	Reliability aged OH Plant - 40+ yrs, 1600 m 8kV, #6 cu, 45 (45ft) poles, 12TX and associated equipment				**$480**		
Rebuild Fisher St, Albert S, Avenue St & Quebec St	Reliability Aged OH Plant - 40+ yrs 15 (50ft) poles 700m 8kV #6 primary, 5TX				**$250**		
GrenFell South of Gibb, Marland, Montrave	Reliability Aged OH Plant - 40+ yrs, 550 m 13.8kV & 8kV, #6cu, 22 poles, 4TX and associated equipment				**$215**		

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM RENEWAL							
OH PLANT REBUILDS - Assets at EOL, Failure Risks, legacy standards, obsolete, Reliability impacts							
Julianna & Bernhard	Reliability Aged OH Plant - 40+ yrs, 855m 8kV, #6 cu, 24 (45ft) poles and associated equipment					$335	
Mary -Rossland to Aberdeen	OH Rebuild - 40+ yrs,1000 m, 1 phase 8kV, #6 cu, 5 TX, 26 (45ft) poles and associated equipment					$340	
Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle	Reliability Aged OH Plant - 40+ yrs, - 2200 m 1 phase 8kV, #6 cu, 55 (45ft) poles, 17 TX and associated plant					$665	
Riverside South - Palace and Hosein	Reliability Aged OH Plant- 40+ yrs, 1000 m 1 phase 8kV #6 cu, 26 (45ft) poles, 4TX, and associated plant					$340	
Riverside North - Regent, EastHaven, EastGrove, Eastdale, Eastborne, EastGlen, Florian Crt	OH rebuild - 40+ yrs, 2350 m 1 phase 8kV, 58 (45ft) poles, 15 TX and associated plant					$630	
King St E 10F1 (Keewatin to Townline)	Reliability Aged OH Plant - 40+yrs, 1000 m,1/0 cu, 21 (55ft) poles, 3phase, 13.8KV, porcelain insulators						500
Vimy Ave, Lasalle Ave - OH Rebuild	Reliability Aged OH Plant - 40+ yrs, 500 m 8kV, #6 cu, 12 poles, 4 TX and associated equipment						175
Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham	Reliability Aged OH Plant - 55+ yrs, 4550 m 8kV, #6 cu, 120 (45ft & 50ft) poles, 35 TX and associated equipment						1042
Grandview, Beaufort and Newbury	OH Rebuild - 40+ yrs,600 m 8kV, #6 cu, 15 (45ft) poles, 3 TX and associated equipment						200
Pole Replacement Program (based on Pole testing & inspection)	Replaced poles deemed to be in critical or poor condition identiifed by testing			$200	$200	$200	200
OH MISCELLANEOUS PROJECTS UNDER MATERIAL THRESHOLD		$628					
	TOTAL OH PLANT REBUILDS	**$2,663**	**$2,410**	**$2,455**	**$2,055**	**$2,510**	**$2,117**

Project 2014 – Proposed OH Rebuilds: Total ~$2.0 million

- Wilson - Wentworth To Bloor: ~$535 thousand
- Adelaide St. E - Wilson to Harmony: ~$400 thousand
- Olive Ave.: ~$120 thousand
- Porcelain switch replacement Program (replacement program started 2013): ~$150 thousand
- Porcelain insulator replacement Program (replacement program started 2013): ~$200 thousand
- Simcoe St. N Rossland to William: ~$280 thousand - Project carried over from 2013 to 2014
- Wilson TS - HONI's ROW - Rear Lot 44 KV distribution Plant Upgrade: ~$350 thousand Project carried over from 2013 to 2014 due to Customer issues

Project 2015 – Proposed OH Rebuilds: Total ~$2.4 million

- Park Rd. Wentworth To Stone including Lakefields, Beaupre, Tremblay, Kenora, Gaspe, Laurentian, Lakeview, Lakeside, Lakemount, Evangeline, Montieth, Bala, Wilson - Wentworth To Bloor : ~$1.3M
- Keewatin (Melrose, Applegrove, Oriole, Willowdale, Springdale) : ~$745 thousand
- Backyard Rear Lot Feed - Rear Simcoe & Masson; Rear Masson & Mary: $365 thousand

Project 2016 – Proposed OH Rebuilds: Total ~$2.2 million

- Rossland - Ritson to Wilson : ~$550 thousand
- Athabasca, Rockcliffe, Belvedere, Labrador, Lisgar, Windermere, Ridgecrest, Wakefield: ~$835 thousdand
- Eastlawn, Winter, Mackenzie, Labrador: ~$360 thousand
- Bloor St. - Oliver to MS11: ~$510 thousand

Project 2017 – Proposed OH Rebuilds: Total ~$1.9 million

- Central Park Blvd. N - Brentwood, Homewood to Harwood: ~$575 thousand
- Lansdowne - Dover, Digby, Surrey, Sussex: ~$335 thousand
- Shakespeare - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct.: ~$480 thousand
- Rebuild Fisher St., Albert S, Avenue St. & Quebec St.: ~$ 250 thousand
- GrenFell South of Gibb, Harland, Montrane: ~$215 thousand

Project 2018 – Proposed OH Rebuilds: Total ~$2.3 million

- Julianna & Bernhard: ~$335 thousand
- Mary - Rossland to Aberdeen: ~$340 thousand

- Gibbons - Glengrove, Rossmount, Glendale, Glen Forest, Glen Alan, Glen Rush, Glenbrae, Glencastle: ~$665 thousand
- Riverside South - Palace and Hosein: ~$340 thousand
- Riverside North - Regent, East Haven, East Grove, Eastdale, Eastborne, East Glen, Florian Crt.: ~$630 thousand

Project 2019 – Proposed OH Rebuilds: Total ~$1.9 million

- King St. E 10F1 (Keewatin to Townline): ~$500 thousand
- Vimy Ave, Lasalle Ave: ~$175 thousand
- Waverley - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham: ~$1.042 million
- Grandview, Beaufort and Newbury: ~$200 thousand

Project 2016 - 2019 – Pole Replacement Program: Total ~$800 thousand

OPUCN completed pole testing during 2004 – 2007. Best practice recommends pole testing to be conducted every 10 years, starting with the poles that are over 30 years old or which have previously identified risks. OPUCN therefore plans to start pole testing and inspection in 2015 on a systematic area by area basis, to identify poles in need of replacement. Pending the results, OPUCN will immediately replace poles that are in very poor condition or deemed urgent that impact public or employee safety, or at critical risk of failure. Poles that are identified as being in poor condition but not critical will be scheduled over the 2016–2019 period. Estimated annual gross expenditure $200 thousand based on approximately 10 -15 poles annually.

Underground Rebuild Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
SYSTEM RENEWAL							
UGPLANT REBUILDS - Assets at EOL, High Failure Risks, legacy standards, obsolete, Reliability impacts							
Rideau St and Anderson Ave- Townhouse complex UG Cable Replacement	Reliability - Aged UG Cable replacement >40 yrs 1600m, single phase primary, town homes, 9 transformers, dip poles	**$204**					
MS13 OH/UG Plant upgrade- 13.8kV/44kV structures (poles) and dips outside MS13 *Westmore Contractor for OH (project carried over to 2014)*	85% completed in 2013 due to service connection work and ice storm. Carry Over to 2014.	**$76**					
Rebuild Londonderry Stm Castlebar Cres, Kilkenny Ct, Cavan Ct, Arklow Ave	Reliability - Aged UG Cable > 40 yrs 1600m, 3 phase #2 cu primary, 12 txs, 2 risers - *UG cable installed in 2013- Final connections to complete*	**$120**					
UG Rebuild Sorrento Ave, Homestead Ct, Cooper Ct,Siena Ct and Salerno St. **Carried over from 2014. City working on clearance issues**	Reliability - Aged UG Cable replacement 40+ yrs 1200m, single phase #2 cu primary, 9 transformers terminations dip poles	**$25**	**$150**				
UG Rebuild - Southgate dr, Southdale Ave, Southdown Dr, Southridge St Subdivision. **Carried over from 2014. City still working on field clearances**	Reliability - Aged 40+ yrs, UG Cable replacement 1150m, single phase#2 cu primary, town homes, 6 transformers Terminations dip poles	**$45**	**$140**				
7 William St - Downtown UG Below Grade Vault	Reliability - Biddle Report - vault not structurally sound. Vault to be rebuilt and VacPAk Switches replaced with remote operated switches	**$400**					
MS 14 13.8kV Feeder lead cable replacement (pot heads leaking).	Reliability - Replace Aged feeder cables> 40yrs at station yard new duct bank 3 new feeder, UG risers poles	**$500**					
Down Crescent, Delmark Ct Townhouse complex	Reliability - Aged 40+ yrs, UG #2 primary cable replacement, 900 m single phase, dip poles (11 Txs Terminations)		**$130**				
Camelot Dr, Merlin Ct, Percival Ct, Lancelot Cres Subdivision	Relaibility Aged 40+ yrs, UG #2 cu primary cable replacement, 1850 m single phase, dip poles (14 Txs Terminations)		**$250**				
Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave	Reliability Aged cable 1973 - cable breakdown with Multiple faults within last 2 years - 2000m, 16tx - Cedar St, Balsam Cres, Lakeview Ave, Bonecho Dr, Chaleur Ave, Wecker Dr		**$260**				
NorthDale Ave,Mohawk St, BeatriceW, Townhouse complex	Reliability Aged UG #2 cu primary cable replacement > 40 yrs, 1200 m single phase, dip poles (6 Txs)			**$147**			
1100 Oxford St Townhouse Complex	Reliability - Aged UG #2 cu primary cable replacement > 40 yrs, 900 m single phase, dip poles (7 Txs)			**$126**			
Athabasca St, Suton Ct, TownHouse complex	Reliability Aged 40+ yrs UG #2 cu primary cable replacement, 1000 m single phase, dip poles (10 Txs)			**$138**			
MS10 - 10F1 & 10F6 Lead cable & lead potheads replacements	Lead cable replacement, lead potheads. 13.8KV UG Feeder to riser poles inside station yard			**$180**			
Aruba Cres, Aruba St, Waverly St N,Bermuda Ave, Antigua Cres	1973 - 2600m, 15tx - Aruba Cres, Aruba St, Waverly St N, Bermuda Ave, Antigua Cres, Barbados St. Fault locating was lengthy and restoration efforts longer than anticipated due to age of cable.			**$338**			
1010 Glen St Townhouse complex	Reliability aged UG 40+ yrs, UG #2 cu primary cable replacement, 1000 m single phase, Townhomes, dip poles (connections to 9 Txs)				**$160**		
Annandale St, Capilano Cres and Capiland Crt Subdivision	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1100 m single phase, dip poles (9 Txs)				**$170**		
CherryDown Dr & Sunnybrae Dr Townhouse	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1000 m single phase, dip poles (14Txs)				**$185**		
Birkdale St. Muirfield St Pinehurst to Subbingham Subdivision	Reliability Aged 40+ yrs, UG #2 cu primary cable replacement, 1500 m single phase, dip poles (8Txs)				**$195**		

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
SYSTEM RENEWAL							
UGPLANT REBUILDS - Assets at EOL, High Failure Risks, legacy standards, obsolete, Reliability impacts							
Gladfern, Galahad, Gentry, Gaylord Subdivision	Reliability - Aged 38+ yrs, UG #2 primary cable replacement 2800 m single/three phase (30 Tx)					$405	
Traddles, Dickens Wickham Subdivision	Reliability aged 38+ yrs,UG #2 primary cable replacement 2200m single phase (22 Tx)					$321	
Outlet Dr - Birchcliffe Ct, Lakeview Park Ave & Valley Dr Townhouse complex	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, 1500 m single phase, dip poles (17Txs)					$195	
Marwood Dr Townhouse complex	Reliability Aged 39+ yrs, UG #2 cu primary cable replacement, 850 m three phase, dip poles (5 Txs)						290
Central Park Blvd North, Exeter St and Trowbridge	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, Townhomes, 2000 m single phase, dip poles (12Txs) includes Townhomes Complex 1055 Central Park Blvd N						256
Ormond Dr, EverGlades, Palmetto,Pompano Ct	Reliability Aged 38+ yrs, UG #2 cu primary cable replacement, 1800 m single phase, dip poles (8 Txs)						234
Beaufort Court	There is OH Rebuild at Beaufort Ave. This include the UG piece at Beaufort Crt. 1976 - 950m, 5 tx, 1 splice - Beaufort Crt, Cleta Crt, Cherry Crt, Conifer Crt						124
UG MISCELLANEOUS PROJECTS UNDER MATERIAL THRESHOLD		$80	$203	$78	$377		
	TOTAL UG PLANT REBUILDS	$1,450	$1,133	$1,007	$1,087	$921	$904

Project 2014 – Proposed UG Rebuilds: Total ~$1.3 million

- 100 Rideau and Anderson Ave. Subdivision- UG Cable Replacement: ~$204 thousand.
- Rebuild Londonderry Stm Castlebar Cres., Kilkenny Ct., Cavan Ct., Arklow Ave. *(carried over from 2013)* ~$120 thousand.
- Sorrento Ave., Homestead Ct., Cooper Ct., Siena Ct. and Salerno St.: City still trying to resolve field clearance issues and has caused delays in project; *will be carried over to 2015*; 2014 expenditure ~$25 thousand.
- Southgate Dr., Southdale Ave., Southdown Dr., Southridge St.: City still trying to resolve field clearance issues and has caused delays in project; *will be carried over to 2015*; 2014 expenditure ~$45 thousand.
- MS 14 – 6 -13.8kV Feeders lead cable replacement (pot heads leaking) including rebuild UG ducts within stations yard: ~$500 thousand; Project partially installed in 2014 and will be placed in service in 2015. The 500 thousand WIP expenditures will be carried into 2015 In service expenditure.

- 7 William St. - Downtown UG Below Grade Vault: Estimated Total ~$400 thousand. As part of an Engineering Consulting Report, this vault is one of the five vaults that was deemed structurally unsound. Based on the criticality and risk prioritization, all four vaults were completed over the period 2011 -2013 and this is the last vault to be rebuilt.

Project 2015 – Proposed UG Rebuilds: Total ~$930 thousand

- Sorrento Ave., Homestead Ct., Cooper Ct., Siena Ct. and Salerno St.: City still trying to resolve field clearance issues and has caused delays in project; *carried over from 2014 into 2015;* ~$150 thousand.

- Southgate Dr., Southdale Ave., Southdown Dr., Southridge St.: City still trying to resolve field clearance issues and has caused delays in project; *carried over from 2014 into 2015*; ~$140 thousand.

- Down Cres., Delmark Ct. – Townhouse complex: ~$130 thousand.

- Camelot Dr., Merlin Ct., Percival Ct., Lancelot Cres.: ~$250 thousand.

- Cedar St., Balsam Cres., Lakeview Ave., Bonecho Dr., Chaleur Ave.: ~$260 thousand.

Project 2016 – Proposed UG Rebuilds: Total ~$929 thousand

- Northdale Ave., Mohawk St., Beatrice W.: Townhouse complex: ~$147 thousand.

- 1100 Oxford St.: Townhouse complex ~$126 thousand.

- Athabasca St., Suton Ct.: Townhouse complex~$138 thousand.

- MS10 - 10F1 & 10F6 Lead cable & lead potheads replacements: ~$180 thousand.

- Aruba Cres., Aruba St., Waverly St. N, Bermuda Ave., Antigua Cres.: ~$338 thousand.

Project 2017 – Proposed UG Rebuilds: Total ~$710 thousand

- 1010 Glen St. - Townhouse complex: ~$160 thousand.

- Annandale St., Capilano Cres. and Capiland Crt.: Subdivision ~$170 thousand.

- Cherry Down Dr. & Sunnybrae Dr.: Townhouse complex ~$185 thousand.
- Birkdale St., Muirfield St., Pinehurst to Subbingham: Subdivision ~$195 thousand.

<u>Project 2018 – Proposed UG Rebuilds: Total ~$921 thousand</u>

- Gladfern, Galahad, Gentry, Gaylord- Subdivision: ~$405 thousand.
- Traddles, Dickens, Wickham, Subdivision ~$321 thousand.
- Outlet Dr. - Birchcliffe Ct., Lakeview Park Ave. & Valley Dr. Townhouse: ~$195 thousand.

<u>Project 2019 – Proposed UG Rebuilds: Total ~$904 thousand</u>

- Marwood Dr. Townhouse Complex: ~$290 thousand.
- Central Park Blvd. North, Exeter St. and Trowbridge: ~$256 thousand.
- Ormond Dr., EverGlades, Palmetto, Pompano Ct.: ~$234 thousand.
- Beaufort Court: ~$124 thousand.

Distribution Station Rebuild Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

Substation breaker replacement program: 2014-2016 - estimated total expenditure is $525 thousand

OPUCN is continuing with its phased program to replace the aging magnetic air breakers with vacuum breakers in the existing switchgear cells. In 2013, OPUCN awarded a four year contract to replace the transformer breakers and bus tie breakers over the period 2013-2016. The program will be completed in 2016. The following table outlines the schedule of the annual breaker replacement*.*

Location	Date	Quantity
MS # 13– 856 Wilson Rd. S	November, 2013	1 (West - DHP)
MS # 7 - 25 Taunton Rd W	November, 2013	3 (West - DHP)
MS # 14– 139 Court St	September, 2014	2 (FPE- DST2)
MS # 5 - 495 Stevenson Rd N	September, 2014	3 (FPE - DST2)
MS # 10 - 36 Keewatin St N	September, 2015	3 (FPE - DST2)
MS # 11 - 443 Bloor St W	September, 2015	3 (FPE - DST2)

MS # 2 - 192 Hillcroft St	September, 2016	3 (West - DHP)
MS # 15 - 1430 Harmony Rd. N	September, 2016	2 (West - DHP)

2014 Project - MS5 T1 power transformer replacement: Total ~$840 thousand

Replace existing Power transformer with new 25kVA transformer unit c/w oil containment. This unit is greater than 30 years old and in November 2013, due to critical/poor gas and oil results/analysis, this unit was removed from service and deemed end of life. Replacement is essential to maintain system reliability.

2014 – 2015 Project - MS14 – metal clad switchgear replacement with arc flash resistant: Total ~$1.5 million

The bus insulation in municipal station (MS) 14 burnt through in August, 2013. Switchgear Integrity has degraded and is questionable as there is now accelerated corrosion resulting from a fire that occurred in 2006. The current equipment condition presents a high risk to reliability.

The switchgear was delivered and installed on site in December 2014 with final testing and commissioning scheduled for January – February 2015.

2014 Expenditure: ~$1.2 million (to be carried into 2015 WIP)

2015 Expenditure: ~$300 thousand

2019 Project - MS5 T2 Power transformer Replacement: Total ~$1.0 million

Replace existing power transformer with new 25kVA transformer unit c/w oil containment. Based on METSCO's Asset Condition Assessment this transformer unit is greater than 30 years old and is starting to show an increase in combustible gas content. OPUCN will be monitoring this unit and plans to replace this in 2019 as it approaches end of life and replacement becomes essential in order to maintain reliability.

2016 – 2018 Project - replacement of 44kV oil circuit breakers: Total ~$1.5 million

Based on METSCO's Asset Condition Assessment 11 44 kV circuit breakers will need to be replaced as they are in excess of 40 years old and are approaching end of life. Their technology is obsolete and replacement parts from suppliers are no longer available. OPUCN proposes to replace these with SF6 vacuum breakers and has so costed the project, but also intends to investigate alternative replacement options through an RFP to interested parties. OPUCN plans to replace these over the period 2016 -2018.

2014 – 2019 Project – annnual reactive or emergency capital replacements: ~ $4.2 million

This investment catergory is estimated at ~$830 thousand per year, over the five year planning period, based on historic perfomance and trend, and covers emergency capital replacements of failed assets that are in service or assets that are damaged due to external factors or conditions (e.g. motor vehicle accidents, storms etc). These capital replacements are non discretionary.

The following are the components for this project category:

- ***Annual unplanned distribution UG transformer replacements: forecast Annual expenditure $220 thousand based on historic trend***

OPUCN generally employs a "run-to-failure" strategy for distribution transformers. Underground vault type and pad mounted type transformers are visually inspected and normally left in service until failure (approximately greater than 40 years).

- ***Annual unplanned UG secondary cable replacements: forecast annual expenditure $180 thousand based on historic trend***

These projects are unplanned and are non discretionary as they are driven by emergency failures or reactive type work. Normally driven by contractor damaging cable or cable failure due to age, site conditions, poor insulation etc.

- ***Annual unplanned distribution OH/UG componenent changeout - forecast annual expenditure $110 thousand based on historic trend***

These projects are unplanned and are non discretionary as they are driven by emergency failures or reactive type work. Assets normally include switches, insulators, arrestors etc.

System Service Capacity Driven Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
SYSTEM SERVICE							
Wilson TS to Thornton TS Load Transfer (Phase 2) - MS11 - OH Plant rearrngement	Reconfigure Thornton feeders and necessary switches as part of System Load Transfer - This will shift approx 3 MVA from 52M3 to 52M2	$140					
Wilson TS to Thornton TS Load Transfer (Phase 2) - Gibb St - Stevenson to MS14	Upgrade from single 44kV circuit to 44kV double circuit along Gibb St to MS 14 (approx 2,200m)	$1,350					
Thornton TS - System Capacity - *Riggs Distler Contractor* *Project carried over to 2014*	Turn key Design and Build. Issues with Intersection delayed work. Working with Region to arrive at solution. 70% completed and carried over to 2014	$362					
15F1 Extension - Harmony Rd, from Coldstream Dr to Conlin Rd East; Conlin Rd East to Townline (tied to C12-209 Region project completion) *Westmore contractor (Project be carried over to 2014)*	Westmore awarded construction contract $175K.. Approx 80% of project will be completed this year. City rescinded approval on Oct 4 as they have decided to construct a new water main (dropping 10 ft below road surface) along Conlin in 2014. That component of project approx 20% will now be carried over to 2014	$78					
Regional Planning - Address Transmission Capacity at **Thornton TS** - Oshawa Requirement for 2 feeders & bus upgrade…	Hydro One (as of Aug 23, 2013) proposes replacement and upgrades of the end of life Power Transformer units. Expected completion before end of 2015. HONI requires Contribution for feeders and associated bus and transmission line upgrades to allow use of capacity. Oshawa requires 2-44kV primary feeders at Thornton. Discussions with HONI and Whitby for solutions are still in progess.		$1,500	$1,500			
Regional Planning - Address Transmission Capacity at **Wilson TS** - Subject to final Outcomes of Regional Planning discussions which starts in Sept 2013	System Capacity: address needs and customer value - Significant Load Growth in North Oshawa due to 407 expansion and attracting new commercial/industrial customers to Oshawa. On going discussions with HONI . Estimated contribution based on HONI proposa/estimate for 2 new feeder positions in 2019-20				$1,000	$1,000	1500
Distribution Capacity - Construct new **MS 9** - 13.8kV Substation to address load growth in North Oshawa compounded by the extension of 407	System Capacity constraints - customer value - Significant Load Growth in North Oshawa due to 407 expansion and attracting new residential and commercial/industrial customers to Oshawa. Require Station and feeder capacity by 2019		$750	$1,000	$3,250	$2,000	
Proposed OH Plant due to new MS9	New 13.8KV distribition feeders to service north Oshawa as per forecasted loads					$1,000	1000

- Interim Load Transfer ~$1.9 million

<u>Project 2014 - Wilson TS to Thornton TS Load Transfer (Phase 2) to provide station capacity at Wilson TS ($140 thousand)</u>

This project includes the reconfiguration of Thornton feeders and installation of cross over ties and switches to allow load transfer from Wilson TS to Thornton TS. The outcomes and benefit of this project is to leverage the available capacity at Thornton TS and enhance switching capabilities to improve system operations and reliability.

In early 2012, discussions with Hydro One Transmission and Hydro One Distribution confirmed transmission capacity constraints at the Wilson TS in north Oshawa and potentially at Thornton TS in south Oshawa. As a result of accelerated development in north Oshawa, OPUCN applied due diligence and proceeded with a short term solution, which was suggested and agreed with Hydro One, that involved the transfer of load from Wilson TS to Thornton TS.

It was stated by Hydro One that there were under-utilized assets at Thornton TS (13.8kV feeders allocated to Whitby that were not fully utilized) and hence, OPUCN may proceed with its plan to alleviate its Wilson TS feeders, via the transfer of required loads to Thornton feeders. This will also allow OPUCN to be in a position to handle present load growth in North Oshawa at Wilson TS. This project started in 2012 and the final cutover of load will be completed in 2014.

<u>Project 2014 - Wilson TS to Thornton TS Load Transfer (Phase 1) - Gibb St. - Stevenson Rd. to MS14. ~ $1.4 million</u>

For similar reasons as above, OPUCN proceeded to upgrade its overhead from a single 44kV circuit to 44kV double circuit along Gibb St. from Stevenson Rd. to MS 14 (approximately 2,200m of overhead line rebuild)

Project 2014 - Thornton TS - System Capacity - Turn key Design and Build. Issues with Intersection delayed work. Working with Region to arrive at solution. 70% completed in 2013 and carried over to 2014 ~$362 thousand

Project involves the installation of 20 poles, 1km of 44kV 3 phase primary lines. In 2013, there were issues with one of the Intersection that required the Region to confirm the final solution. There were delays in receiving the final solution which caused the project to be carried over to 2014.

- Thornton TS Capacity Upgrades – Capital Contribution to HONI

Project 2015 – 2016 – Provide HONI TX with capital contributions to address Oshawa Requirement for 2 feeders at Thornton TS. ~$3 million

Based on initial discussions, Hydro One has scheduled the replacement of both transformers at Thornton TS, which had reached its end of life, all by the end of 2015, including the installation of a grounding neutral reactor to resolve short circuit capacity constraints for FIT installations.

The intent was to provide OPUCN with two new feeder positions and upgrade the bus tie to provide feeder and station capacity. The estimate provided by Hydro One is approximately $3 million which is included in OPUCN DS plan, with $1.5 million being applied in each year 2015 and 2016 to smooth out the level of investments. This original proposal is now being reconsidered and further local operational meetings are required to provide interim solutions to address the loading issues.

- Wilson TS Capacity Upgrades – Capital Contribution to HONI

Project 2017 – 2019 - Address Transmission Capacity constraints at Wilson TS – Provide HONI TX with capital contributions to provide station capacity at Wilson TS. ~ $3.5 million

Similar to Thornton TS, OPUCN and HONI are having ongoing discussions to address the capacity constraints at Wilson TS. As described above the latest "Needs Assessment" report suggests that the long term solution is still under review and most likely will involve the reinstatement of the new Enfield TS construction, or a new DESN at Wilson TS, as there is space available at the station yard.

These options will be discussed further at the Regional Planning and Local Planning meetings to determine best cost effective solution for all impacted stakeholders, and one that will be in the best interest of the customers. Expected completion of the Regional Infrastructure Planning (RIP) is 6 months. HONI has provided its Support Letter to acknowledge the preliminary contribution of $6.5 million to cover the requirements of two breaker positions and associated feeders at both Thornton and Wilson if required. This may increase to $10 to $12 million subject to the outcomes of the RIP process.

- New Distribution Station (MS9) and associated primary overhead feeders

Construct new distribution 44kV-13.8kV station (MS 9) and required 13.8kV distribution feeders to service new developments in North Oshawa. Estimated total expenditure $7 million (station) and ~$2 million (13.8KV feeder extensions)

In 2008, OPUCN proposed the construction of the new substation MS9. With the decline in the economy and the uncertainty and delays in the opening of the highway 407 extension, the load growth in Oshawa did not materialize as originally forecasted and this project was placed on hold.

With the opening of the 407 extension in 2015 along with the aggressive promotional efforts from the City of Oshawa to encourage new development, the load growth has started to materialize. On-going collaboration with the City, have confirmed the projected load forecast and given the timeline to construct a new substation (on average three to four years) OPUCN, with the support of the City, is resuming work on design and construction of this new substation in order to meet the now forecast load growth timing.

OPUCN plans on utilizing the land previously purchased for this station. Existing substations do not have the capacity nor the feeder capabilities to extend to the north sections of Oshawa where the future load growth will surely occur. OPUCN will need to proceed in 2015 to issue an RFP/RFQ for a turn-key design, construction and commissioning to ensure additional distribution capacity is made ready in 2019.

Grid Modernization Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

Project 2014 -2015 – UG Distribution Automation Project - Downtown Vaults Automation. Estimated total expenditure over two years $1.43 million. [Reference UtiliWorks Smart Grid Report Pg. 23 & 11]

This project will improve system reliability and provide visibility at Downtown area underground facilities. It will also provide communication infrastructure that can be linked to the planned Outage Management System (OMS).

This project involves automating the downtown underground system by installing relays on existing automation-ready switches and replacing existing switches with fully automated switches in 15 vault rooms. Communication infrastructure will be implemented through installation of fiber network connecting the vault rooms to SCADA.

The installation of an Inter-Control Centre Communications Protocol (ICCP) system[1] will complete the communication network that will provide visibility to our system to increase operational efficiencies and to better manage/operate the downtown distribution grid.

Transformer primary and secondary monitors will also be introduced to existing transformers in six vault rooms serving multiple customers. This will allow OPUCN to monitor transformer health, capacity and primary and secondary loading and will, among other benefits, enhance demand management capabilities for demand management.

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[1] The ICCP or TASE.2 protocol is internationally recognized standard for communications between electrical utility control centers (transmission and distribution).

This project is ongoing and will be completed over a three year period (2013-2015).

Benefits from this project are:

- Overall Improved Reliability
    - Response to outages will improve through quick SCADA fault detection
    - The scope and length of outages will be minimized by remotely isolating faults
- Power Quality and Demand Management
    - Accurate data and historical information can be obtained from the relays and monitors for system planning and operation
- Automate and connect vaults to SCADA to provide remote visibility of the entire underground downtown distribution system.
- System Optimization
    - Remote monitoring of secondary loading will improve management of service connections.

Project 2016-2019 – UG Self-Healing Distribution Automation Project – installation of a "smart grid" downtown automated system. Estimated total expenditure over four years ~$310 thousand. [Reference UtiliWorks Smart Grid Report Pg. 23 & 11]

Building from its Underground Distribution Automation Project – Downtown Vaults Automation, OPUCN will, at this final phase, install remote switching devices and an intelligent software application to allow the "intelligent" system to automatically and remotely make operational decisions in response to fault detection, isolating faults and responding by switching to perform load transfers or restoration.

Project 2017 -2019 – OH Self-healing Intelli-Rupters Switches. Estimated total expenditure over three years $955 thousand. [Reference UtiliWorks Smart Grid Report Pg. 23 & 11]

OPUCN plans to install eight switches on 13 identified feeders over the period 2016–2019.

OPUCN has proven successful operations with its pilot installation whereby fault was identified, switches operated successfully as designed to quickly isolate the fault and minimize the number of customers affected by fault, thereby improving overall reliability. OPUCN plans to install more Self-Healing, Intelli-Rupters switches on its poor performing feeders.

Project 2018-2019 – Voltage Monitoring (Volt-Var optimization and Reduction in Distribution Losses). Estimated total expenditure over two years $450 thousand. [Reference UtiliWorks Smart Grid Report Pg. 22 & 11]

OPUCN presently needs better visibility into the condition of its network, to help identify and reduce its line losses. The outcomes of the project will help OPUCN achieve better operational system efficiencies thereby reducing customer costs. Volt-Var controls can help identify the cause of line losses and ultimately reduce them over time.

With the accelerating deployment of advanced sensor network, smart metering infrastructure, and remote control capability, there is a growing need for smart applications like Volt-Var controls that optimize the operation of the distribution system. Volt-Var technology can help distribution system to operate efficiently and reliably while reducing energy and CO_2 footprint.

The Volt-Var system enables detailed and accurate modeling of the distribution system components and connections. It rapidly identifies the optimal voltage and VAR operation strategy, using advanced mixed-integer optimization algorithms. The OPUCN Volt-Var system is comprised of system software distribution system switches, fault indicators, and communication devices, all of which will be installed over the period of two years.

Project 2015–2019 - Distribution System Supply Optimization. Estimated Total expenditure is $175 thousand. [Reference UtiliWorks Smart Grid Report Pg. 25 & 11]

OPUCN's distribution system is fed from two different wholesale meters. The distribution system is designed to provide high reliability for customers by managing the peak demand at its two transmission stations. At present, the supply management and switching of distribution loads between the two transmission stations is manual and lacks real-time visibility and decision making. 'Distribution System Supply Optimization' will provide a new real-time approach to balance performance and operational objectives by avoiding two separate monthly demand peaks at two different wholesale meters. This will lower monthly transmission charges and increase operational effectiveness.

Distribution System Supply Optimization mainly involves software component and SCADA integration.

General Plant Capital Program Details

In providing capital expenditure details, OPUCN has applied a materiality threshold of $100,000, in accordance with section 2.4.4 of the Guidelines. An additional "Miscellaneous Project" category is included to capture projects/programs included in the investment category which do not individually exceed the materiality threshold.

The total General Plant investments over the 2015 – 2019 period are preliminary and is approximately $4.9 million.

The following Table summarizes the List of projects within the 2014-2019 period, that are in the General Plant category, and that exceed the materiality threshold.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	**BRIEF PROJECT DESCRIPTION**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
GENERAL PLANT							
Outage Management System (OMS fully integrated with SCADA, GIS, AMI, CIS, IVR) **Phase 1 carried over from 2014**.	Need to proactively provide timely updated communication to customer on outage status. Remotely operate switching, identify outage areas and reduce overall restoration time and outage duration through faster fault identification and automated data mgmt	**$75**	**$850**				
Mobil Work Force - will focus on having OMS fully operational before moving into MWF	leverage automated dispatch for crews assignment of work	**$0**		**$50**	**$50**		
Operational Data Storage (ODS) Replacement	existing ODS no longer able to provide Operational effectiveness. Needs to be replaced			**$400**			
Operational Capital Projects (GIS & MAS/ODS enhancements) individual projects **UNDER Material Threshold**	Ongoing enhancements in MAS/AMI, GIS/OMS/ODS	**$170**		**$85**	**$85**	**$160**	**160**
FLEET Vehicle- 83ft double bucket damaged in 2014 and replaced	Unplanned replacement of Truck 6 due to fire & breakdown. 2014 inlcudes delivery of chasis and in 2015 will include full truck delivery with body and boom ($370K less $100K tradein = $270K in 2015)	**$100**	**$270**				
FLEET Vehicle- 46ft single Bucket one in 2016 & 2017	Replace two vehicles, each approaching end of life			**$375**	**$375**		
FLEET - Individual **vehicles UNDER MATERIAL THRESHOLD**	smaller vehicle purchases to minimize fuel intake and operations	**$55**	**$150**	**$40**	**$65**	**$190**	**170**
Facilities - Refurbish & rearrange floorplan of Customer service area and Finance area to improve operational efficiencies	current floorplan of CSR work stations and Finance area is causing disruptions to the day to day function. Need better and effective layout	**$0**					
Renovate Tech area for additional work station and washroom (100K 2015) plus pole yard storage $75K for material Cable reels space to be cleared for vehicle space	Reaarrange floor plan to create 2 additional work station/area and parking spaces in parking lot		**$175**				
Servers Upgrades in Production and DRP - End of Life in 2018. No longer supprted. Originally installed end 2012	Servers currently for production environment and DRP operations will reach end of life in 2018. No longer supported. Originally installed in end of 2012 Full replacement required for all business application and operations					**$200**	
MISCELLANEOUS PROJECTS **(Major Tools, Minor Leasehold improvements)** **UNDER MATERIAL THRESHOLD**		**$144**	**$100**	**$100**	**$100**	**$100**	**100**
MISCELLANEOUS Office Capital Expenditure (IT hardware and software Systems) Individual Projects UNDER MATERIAL THRESHOLD		**$90**	**$130**	**$130**	**$80**	**$80**	**80**
	TOTAL GENERAL PLANT	**$634**	**$1,675**	**$1,180**	**$755**	**$730**	**$510**

Project 2014 – 2019 - Outage Management System (OMS) - Includes SCADA, GIS, CIS and smart meter integration and necessary enhancements to existing systems- Estimated Total expenditure over two years $925 thousand.

This OMS project was scheduled in phases, with Phase 1 being in 2012 and final phase of project ending December 31, 2015.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
GENERAL PLANT							
Outage Management System (OMS fully integrated with SCADA, GIS, AMI, CIS, IVR) **Phase 1 carried over from 2014**.	Need to proactively provide timely updated communication to customer on outage status. Remotely operate switching, identify outage areas and reduce overall restoration time and outage duration through faster fault identification and automated data mgmt	$75	$850				

Phase 1 involved the data preparedness and accuracy including secondary connectivity in the GIS, to allow integration of the AMI, CIS and GIS.

The final components of the project are scheduled for completion over 2014 and 2015. In 2014, the forecast expenditure of approximately $75 thousand covers the subject matter expert services of an independent third party consultant to:

- help define OPUCN business requirements,
- prepare the RFP for bidders' quotes and help select OMS vendor,
- provide process maps for existing and proposed business operations for "before" and "after" the OMS is in service.
- Project "start up" and implementation of a "pilot system" to refine design criteria for successful integration of all systems

In 2015, the forecast expenditure of approximately $850 thousand covers:

- Purchase of OMS including interface requirements
- Integration services from vendors of other systems (AMI, GIS, SCADA, CIS, IVR) and necessary enhancements or upgrades
- Services from third party independent consultant to:
    - Project manage
    - Create test plan - including functional, system integration, stress performance, and user acceptance elements.
    - Prepare test cases

- Execute functional, system integration, and stress/performance tests
- Create end-user training documentation
- Train end-users

Benefits of the OMS fully integrated with smart meters, SCADA, GIS, CIS, and IVR functionality include:

- proactively identify outages before customer calls to report the outage;
- Improve customer satisfaction as customer outage duration, frequency and impacts are reduced. Also provide customers with more frequent or timely up to date information during an outage, including number of customers affected and status of the restoration work in progress and or expected completion.
- Achieve operational savings resulting from reduced restoration costs as faults and outages are identified and located faster through automation, and crews will be directed or dispatched quicker to conduct restoration work.
- Improves performance in system and customer reliability and hence reporting metrics.

Project 2016 – 2017 - Mobile Work Force Solution – Estimated Total Expenditure $100 thousand.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
GENERAL PLANT							
Mobil Work Force - will focus on having OMS fully operational before moving into MWF	leverage automated dispatch for crews assignment of work	$0		$50	$50		

This project involves the use of hand held devices or laptop in trucks with dispatch functionality tied to the CIS and GIS systems. It will leverage a works management system and will:

- Optimize crew utilization and allow quicker response to trouble or service calls as work is assigned to closest crew
- Improve customer service

- Provide safety component in knowing location of crew when not responding

Project 2015 – 2019 - Fleet (New) vehicle: Total cost $100 thousand (2014); $270 thousand (2015); $315 thousand (2016); $325 thousand (2017).

This program includes the replacement of vehicles that are approaching end of useful life and undergo frequent or high maintenance, have difficulty starting or become a high risk when in use.

OPUCN plans to continue with much needed reasonable investments to sustain our fleet, reduce our maintenance and operation costs and hence improve operational efficiencies.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
GENERAL PLANT							
FLEET Vehicle- 83ft double bucket damaged in 2014 and replaced	Unplanned replacement of Truck 6 due to fire & breakdown. 2014 inlcudes delivery of chasis and in 2015 will include full truck delivery with body and boom ($370K less $100K tradein = $270K in 2015)	$100	$270				
FLEET Vehicle- 46ft single Bucket one in 2016 & 2017	Replace two vehicles, each approaching end of life			$375	$375		
FLEET - Individual **vehicles UNDER MATERIAL THRESHOLD**	smaller vehicle purchases to minimize fuel intake and operations	$55	$150	$40	$65	$190	170

1) In 2014, unplanned replacement of Truck 6 due to fire & breakdown. 2014 includes delivery of chassis and in 2015 will include full truck delivery with body and boom ($370 thousand less $100 thousand trade in = $270 thousand in 2015)

2) Two new 46ft single bucket with increased capacity and reach to replace old vehicle: One in 2016 - $315 thousand and the other in 2017 - $325 thousand

3) Replacement of smaller vehicles that are under the material threshold (e.g. vans, pick-ups trucks, trailers)

Project 2015-2019 Facilities (~$425 thousand)

Based on historic trend, an estimated $50,000 is proposed annually to cover leasehold improvements at the Head Office or Work Center facilities. This amount is included in the forecast expenditures over the period 2015–2019.

2014-2019 MATERIAL CAPITAL EXPENDITURES BY PROJECTS SORTED BY CATEGORY		2014 NET	2015 NET	2016 NET	2017 NET	2018 NET	2019 NET
CAPITAL	BRIEF PROJECT DESCRIPTION	$'000	$'000	$'000	$'000	$'000	$'000
GENERAL PLANT							
Renovate Tech area for additional work station and washroom (100K 2015) plus pole yard storage $75K for material Cable reels space to be cleared for vehicle space	Reaarrange floor plan to create 2 additional work station/area and parking spaces in parking lot		$175				
MISCELLANEOUS PROJECTS **(Major Tools, Minor Leasehold improvements) UNDER MATERIAL THRESHOLD**		$144	$100	$100	$100	$100	100
MISCELLANEOUS Office Capital Expenditure (IT hardware and software Systems) Individual Projects UNDER MATERIAL THRESHOLD		$90	$130	$130	$80	$80	80

In addition for 2015, OPUCN is making improvements in the Design Tech Buildings to install an additional work station and an additional washroom facility for ladies. Currently there is one washroom in this Design building to serve both ladies and gents. There are 15 people located in this single storey building of which five are women and 10 are men. The estimated cost for these improvements is $100 thousand.

In addition OPUCN plans to leverage the space in their pole yard to house Cable material that are currently in the Office parking lot. OPUCN in 2015 plans to build a secure monitored housing in their pole yard for Cable reels and other material and equipment. This proposal is estimated to be $75 thousand in 2015

Project 2015-2019 Major Tools and Equipment (~$250 thousand)

The need for new and replacement tools and equipment is essential to perform jobs safely and efficiently. Annual expenditure is based on historic trend for replacements for 2014–2018 is an estimated cost of $50,000.

Project 2018 - IT Server upgrades and replacements (~$200 thousand):

OPUCN has identified the following IT server infrastructure that were originally deployed in 2011:

Production site:

1) One IBM BladeCenter Chassis with all the redundant modules

2) Seven IBM HS23 Blade servers

3) IBM SAN with an expansion module

4) One IBM x3500 servers

DR Site:

1) Five IBM X3650 standalone servers

2) IBM SAN

All of the above servers will reach its end of life cycle in 2018 as it will be seven years in production or service. IBM will not sell or provide maintenance on those devices that has reached the end of life cycle. Normal or Standard hardware retirement policy or practice is five years since the cost of maintenance at sixth and seventh years combined is almost same as purchasing the new equipment. The older the hardware, the more frequently it breaks.

Scope of work includes the following:

1) Hardware procurement from authorized vendor (May take more than 30 days from the date of purchase)

2) Installation and configuration of the hardware (will require consulting service from the vendor)

3) Deployment of Operating systems

4) Data migration from the existing systems to the new systems (will require consulting service)

5) Testing the new systems

6) Decommissioning the existing systems