Exhibit K1.4
June 30, 2015

EB-2014-0101

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Oshawa PUC Networks for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through December 31, 2019.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")
CROSS-EXAMINATION COMPENDIUM

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Ontario

BY E-MAIL

June 3, 2015

TO: All Licensed Electricity Distributors
All Other Interested Parties

RE: Allowance for Working Capital for Electricity Distribution Rate Applications

This letter provides an update to the OEB's policy for the calculation of the allowance for working capital for electricity rate applications.

Effective immediately, the OEB is a adopting a new default value of 7.5% of the sum of the cost of power and operating, maintenance and administration (OM&A) costs. As in the past, distributors who do not wish to use the default value can request approval for a distributor-specific working capital allowance supported by the appropriate evidence from a lead-lag study or equivalent analysis.

The OEB is also of the view that the use of the default value should only be implemented during a cost of service application, with a few exceptions as discussed further in this letter. For a custom incentive rate-setting (Custom IR) application distributors are expected to file robust evidence of costs and revenues, and the review of these applications is expected to require considerable resources from both the OEB and the distributor. It is therefore reasonable to expect distributors choosing this option to file evidence in support of their requested working capital allowance, rather than the use of a default value.

Background

Section 2.5.1.3 of the *Filing Requirements for Electricity Distribution Rate Applications* for the 2015 rate year, issued on July 18, 2014, provided for two approaches that an applicant could take for the calculation of the allowance for working capital: 1) the 13% allowance approach; or 2) the filing of a lead-lag study. The second of these approaches has been optional for all utilities that have not been directed to conduct a lead-lag study by the OEB.

The OEB has been using a default value approach to calculating working capital allowance since the 1st Generation Rate Handbook was issued in 2000. At that time, the default value was established as 15% of the total of the cost of power and OM&A expenses. By letter dated April 12, 2012, the OEB reduced the default value to 13% after lead lag studies routinely produced results of less than 15%.

It has become apparent to the OEB that average working capital requirements have been lowered as a result of a number of technical changes that reduce the actual time between service provision and payment. These include: 1) the substantial completion of the smart meter rollout and advanced metering infrastructure, which reduces aggregate meter reading time ; 2) wider adoption of monthly billing, resulting in a shorter period from service to payment; 3) customer information system updates, which reduce time required to calculate customer bills; and 4) general process improvements. The adoption of mandatory monthly billing for all distributors by December 31, 2016, should result in further downward pressure on working capital requirements. Considering all of these current and forthcoming changes, the OEB determined that a review of its approach to working capital allowance was warranted.

Working Capital Allowance for the 2016 Rate Year

The OEB continues to believe that a default value approach is an efficient alternative for setting the working capital allowance. However, a default value should not result in a working capital allowance that is reasonably expected to be higher than what would result from the use of the more accurate and detailed approach of completing a lead-lag study. The OEB also considers that maintaining a default value that is too high does not incent a utility to study its business processes and improve productivity, which would be at odds with the principles embedded in its Renewed Regulatory Framework.

Therefore, the OEB has determined that, effective immediately, the default value for working capital allowance for electricity distributors will be 7.5% of the sum of cost of power and OM&A. The default value will be reflected in the 2015 edition of the *Filing Requirements for Electricity Distribution Rate Applications* for 2016 Rate Applications.

This determination is based on a review of a range of results for lead-lag studies filed by distributors, which showed that working capital allowance results have been declining. For the applications filed for 2015 rates, the results have ranged from 7.4% to 12.7% of the sum of the cost of power and OM&A. Given that many of the financial settlement processes are common between distributors, and all distributors will be required to bill on a monthly basis by the end of 2016, the OEB is adopting a new default of 7.5%. In the OEB's judgment, this default reasonably reflects not only the range of inputs that distributors have reported to the OEB, but also the forthcoming policy changes regarding mandatory monthly billing. The adoption of this new lower default value reflects a goal that all distributors strive for best practices in their administrative processes while supporting a distributor's basic cash flow requirements.

Analysis

To support the OEB's consideration of a new default value, OEB staff reviewed eight lead-lag studies filed with the OEB since 2010 and evaluated the key factors in those studies. OEB staff also considered elements external to a distributor's own operations, such as the cost of power settlement process, and factored in the billing standards identified in the Distribution System Code, such as the identification of a minimum payment period of 16 days from the date on which a bill was issued to a customer. A summary of the results of the OEB staff analysis is attached to this letter as Appendix A. The analysis, which selected a combination of median inputs as well as values that reflect OEB policy, resulted in a calculation of a default value for the working capital allowance of 7.5%.

The OEB also commissioned a jurisdictional review to determine if there are other approaches to the funding of working capital requirements. This review is attached as Appendix B. All jurisdictions reviewed generally included an allowance for working capital to be treated as an asset, attracting a return. On this basis, the OEB does not believe that a fundamental change to its approach to funding working capital requirements is warranted.

The OEB will continue to monitor factors such as the elimination of the debt retirement charge for residential customers, the end of the Ontario Clean Energy Benefit and implementation of the Ontario Electricity Support Program as of January 1, 2016 to determine if they have an effect on cash flow.

Implementation

The new policy is effective immediately. Changes to working capital allowance costs will be implemented only in cost of service and Custom IR applications unless otherwise determined by the OEB in a prior decision. This will allow for all of a distributor's costs to be considered at the same time. The OEB adopted the same approach when it amended its cost of capital policy in 2009.

The OEB recognizes that a specific utility's own systems, processes and customer mix will influence its working capital needs. While there are similar settlement processes, lead-lag results are not directly interchangeable among utilities. Distributors can use a lead-lag study or equivalent analysis to support a request for a distributor-specific working capital allowance.

While the use of the default value will no longer be applicable to Custom IR applications, given the timing of this new policy, distributors that have filed a Custom IR application for rates effective January 1, 2016 may use the 7.5% default value to calculate their working capital allowance rather than file a lead-lag study as part of their application.

For questions relating to this amendment please contact IndustryRelations@ontarioenergyboard.ca.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

Allowance for Working Capital for Electricity Distributors

June 3, 2015

Appendix A

The following is a summary of the results of OEB staff analysis, based on its review of eight lead-lag studies provided to the OEB since 2010.

		Revenue Periods (Lag Days)					Expenses (Lead Days)				
		Service	Billing	Collection	Processing	Total	Lead Days	Net Days	Weighting Factor	Weighted Lead/Lag Days	WCF***
Elements of Working Capital											
1	Cost of Power	15.2	17.5	22.0	1.4	56.1	(32.7)	23.40	82.8%	19.38	
2	Payroll etc.*	15.2	17.5	22.0	1.4	56.1	(9.4)	46.70	5.2%	2.43	
3	Other OM&A	15.2	17.5	22.0	1.4	56.1	(7.8)	48.30	2.8%	1.35	
4	PiLs, etc.**	15.2	17.5	22.0	1.4	56.1	(29.1)	27.00	9.2%	2.48	
5	Sub Total								100.0%	25.64	7.0%
6	HST								0.5%		0.5%
7	Total										7.5%

Element	**Determination**
Service Period	Reflects mandatory monthly billing: 365.25÷12÷2=15.22 days
Billing Period	Median based on observed range of 13.0 days to 19.0 days
Collection Period	Minimum payment period plus allowances for payments by mail as specified in s. 2.6 of the Distribution System Code. Observed sample range is 21.8 days to 29.1 days
Processing Period	Median based on observed range of 1.0 to 1.5 days
Lead Days	Median based on observed results for each expense element
HST	Median based on observed range of 0.3% to 1.4%
Weighting Factor	Reflects proportions of cost of power and OM&A expense categories based on median values from sample studies

*Payroll includes benefits. **PiLs also includes interest and debt repayment costs.
*** Working Capital Factor calculation: Weighted Lead/Lag Days ÷ 365.25 days per year + HST factor.

UPDATED WORKING CAPITAL ALLOWANCE

(based on 2013 data)

Revenue Lag

Service Lag		**17.44**
Billing Lag		17.00
Collection Lag		**21.46**
Paym Proc. Lag		1.50
		57.40
Distribution	97.85%	56.17
Other (-24.29 days)	2.15%	-0.52
		55.65

WCA Calculation

	Revenue Lag	Inventory Lag	Expense Lead	Net Lag	WC Factor	Expenses	WC Requirement
Cost of Power	55.65		20.89	34.76	9.52%	102,012,056	9,713,543
OM&A - payroll	55.65		**10.63**	45.02	12.33%	5,667,950	699,023
OM&A - supplier	55.65	50.88	17.75	88.78	24.32%	5,389,853	1,310,918
OM&A - mun. Tax	55.65		**(16.50)**	72.15	19.77%	152,292	30,102
Interest	55.65		**12.40**	43.25	11.85%	1,910,000	226,296
PILS	55.65		12.50	43.15	11.82%	240,000	28,369
Debt retirement	55.65		30.50	25.15	6.89%	7,532,929	518,949
Sub-Total						122,905,080	12,527,201
HST						1,446,444	(126,495)
Total						124,351,524	12,400,706

Working Capital Allowance **10.95%**

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.

Building a better working world

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

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

IESO Invoice Amounts and Payment Dates

Month	Invoice Total	Date Paid (Final Amount)	$	Days From End of Month	Date Paid (Margin Call)	$	Days From End of Month	Date Paid (Margin Call)	$	Days From End of Month	Date Paid (Margin Call)	$	Days From End of Month	Date Paid (Margin Call)	$	Days From End of Month	Weighted Average Days From End of Month
31-Jan-13	$11,685,026	19-Feb-13	3,084,150	19	25-Jan-13	1,950,212	-6	31-Jan-13	2,121,008	0	06-Feb-13	2,162,201	6	13-Feb-13	2,367,455	13	7.76
28-Feb-13	$8,833,674	18-Mar-13	1,549,886	18	26-Feb-13	2,762,558	-2	06-Mar-13	2,298,075	6	13-Mar-13	2,223,155	13				7.37
31-Mar-13	$9,287,110	17-Apr-13	2,763,569	17	28-Mar-13	2,038,503	-3	04-Apr-13	2,465,348	4	12-Apr-13	2,019,690	12				8.07
30-Apr-13	$8,869,964	16-May-13	4,750,031	16	29-Apr-13	2,033,615	-1	06-May-13	2,086,318	6							9.75
31-May-13	$7,675,317	18-Jun-13	3,813,676	18	31-May-13	1,899,855	0	07-Jun-13	1,961,786	7							10.73
30-Jun-13	$9,262,497	17-Jul-13	5,951,438	17	04-Jul-13	3,311,059	4										12.35
31-Jul-13	$12,813,031	19-Aug-13	4,729,356	19	26-Jul-13	2,266,653	-5	30-Jul-13	1,922,273	-1	06-Aug-13	1,999,660	6	08-Aug-13	1,895,089	8	8.10
31-Aug-13	$9,084,700	18-Sep-13	2,797,089	18	29-Aug-13	2,212,034	-2	05-Sep-13	2,134,433	5	11-Sep-13	1,941,144	11				8.58
30-Sep-13	$9,549,261	17-Oct-13	4,735,653	17	02-Oct-13	2,599,433	2	09-Oct-13	2,214,175	9							11.06
31-Oct-13	$8,028,606	19-Nov-13	4,183,246	19	01-Nov-13	1,928,082	1	08-Nov-13	1,917,278	8							12.05
30-Nov-13	$9,948,720	17-Dec-13	3,191,542	17	27-Nov-13	1,908,214	-3	04-Dec-13	2,542,013	4	11-Dec-13	2,306,951	11				8.45
31-Dec-13	$14,282,560	17-Jan-14	5,478,515	17	27-Dec-13	2,554,104	-4	02-Jan-14	2,189,000	2	07-Jan-14	1,964,458	7	13-Jan-14	2,096,483	13	8.98
	$119,320,467		$47,028,151			$27,464,322			$23,851,707			$14,617,259			$6,359,027		9.44
																	24.64

Month	Invoice Total	Date Paid (Final Amount)	Days From End of Month	Weighted Average Days From End of Month
31-Jan-13	$11,685,026	19-Feb-13	19	1.86
28-Feb-13	$8,833,674	18-Mar-13	18	1.33
31-Mar-13	$9,287,110	17-Apr-13	17	1.32
30-Apr-13	$8,869,964	16-May-13	16	1.19
31-May-13	$7,675,317	18-Jun-13	18	1.16
30-Jun-13	$9,262,497	17-Jul-13	17	1.32
31-Jul-13	$12,813,031	19-Aug-13	19	2.04
31-Aug-13	$9,084,700	18-Sep-13	18	1.37
30-Sep-13	$9,549,261	17-Oct-13	17	1.36
31-Oct-13	$8,028,606	19-Nov-13	19	1.28
30-Nov-13	$9,948,720	17-Dec-13	17	1.42
31-Dec-13	$14,282,560	17-Jan-14	17	2.03
	$119,320,467			17.69
				32.89

OSHAWA PUC NETWORKS INC.

Response to Energy Probe Research Foundation (Energy Probe) Interrogatory 2.0-Energy Probe-18

Ref: Exhibit 2, Tab A, Schedule 1

a) Please show the calculation of the weighted average service lag of 20.41 days for 2012 and 21.44 days for 2013. Please show all figures and assumptions used.

b) If the larger revenue customers were billed near the beginning of each month, would this result in OPUCN having a service lag that is shorter than the typical midpoint of 15 days? If not, please explain fully.

c) Please confirm that all the revenue lags (service, billing, collection, payment processing) calculated in 2012 included the impact of the leap year.

Response:

a) The calculation takes the average end of month unbilled revenue at month ends as a percent of average monthly billed revenue converted into days of sale, divided by two plus billing processing time.

Average unbilled revenue at month ends was $11,737,285 in 2012 and $12,566,542 in 2013 compared with average billed revenue of $10,852,411 and $11,164,410 in 2012 and 2013 respectively. This converts to 32.89 and 34.23 days of sale or 16.45 and 17.11 days when divided by two. Add 4 days to each for processing.

b) The calculation uses actual unbilled service amounts at month end measurements - the lead-lag study was based on aggregate of all customer revenues.

c) Calculations did not include the impact of leap year in 2012, this impact was considered immaterial.

OSHAWA PUC NETWORKS INC.

**Response to Energy Probe Research Foundation (Energy Probe)
Interrogatory 2.0-Energy Probe-22**

Ref: Exhibit 2, Tab A, Schedule 1

a) Do the cost of power expense leads of 19.70 and 20.89 days indicate that based on an average month of 15.21 days, the payments are made on average 4.49 days (2012) and 5.68 days (2013) following month end?

b) Please provide a table that shows for each month of 2012 and for each month of 2013, the amounts billed and paid to the IESO, along with the payment date associated with the invoice.

c) Please provide a table that shows for each month of 2012 and for each month of 2013, the amounts billed and paid to embedded generators, along with the payment date associated with each of the invoices.

Response:

a) Cost of Power expense lead was calculated using average Power Accounts Payable at month end and Total Power expenses for the year as stated in the report. The calculation is (average Power AP/Total Power expenses) x 365 as stated in the report.

b) The calculations were based on year-end overall total power expenses and average month end Power Accounts Payable balances.

c) The calculations were based on year-end overall total power expenses and average month end Power Accounts Payable balances.

Description	2014	2015	Weather Normal Forecast 2016	2017	2018	2019
Actual kWh Purchases	1,134,970,143					
Predicted kWh Purchases	1,171,374,403	1,160,305,591	1,182,640,749	1,204,049,042	1,223,261,454	1,243,933,398
% Difference	3.2%					
Billed kWh	1,091,642,390	1,106,471,443	1,127,632,379	1,147,905,212	1,166,079,671	1,185,641,599
Billed kW	1,137,326	1,177,515	1,195,735	1,218,716	1,240,628	1,263,762
By Class						
Residential		1.5%	3.0%	3.0%	3.0%	3.0%
Customers	50,203	50,977	52,507	54,082	55,704	57,376
kWh	485,503,507	488,310,442	498,776,280	507,323,389	514,621,120	522,614,242
GS<50		1.3%	3.0%	3.0%	3.0%	3.0%
Customers	3,953	4,002	4,122	4,246	4,374	4,505
kWh	133,729,082	134,064,266	136,882,505	139,185,344	141,163,781	143,365,516
GS>50		0.9%	3.0%	3.0%	3.0%	3.0%
Customers	503	507	522	538	554	571
kWh	336,406,114	337,307,809	345,773,098	353,105,417	359,809,880	367,053,276
kW	831,789	851,954	873,335	891,855	908,789	927,084
Large User						
Customers	1	1	1	1	1	1
kWh	42,700,435	42,639,586	42,660,606	42,752,494	42,718,997	42,532,142
kW	93,203	96,450	96,498	96,706	96,630	96,207
I2		2	1	1	2	1
Customers	11	13	13	13	14	14
kWh	81,400,346	92,882,892	95,588,035	97,937,461	100,041,056	102,232,671
kW	186,714	205,191	211,167	216,358	221,005	225,846
Streetlights		1.2%	3.0%	3.0%	3.0%	3.0%
Connections	12,465	12,619	12,998	13,388	13,790	14,203
kWh	9,155,875	8,545,613	5,251,754	4,917,091	5,064,598	5,216,519
kW	25,520	23,819	14,638	13,705	14,116	14,540
Sentinels						
Connections	24	23	22	22	21	20
kWh	35,812	34,297	32,910	31,630	30,312	28,944
kW	100	100	96	92	89	85
USL						
Connections	296	296	296	296	297	297
kWh	2,711,219	2,686,537	2,667,193	2,652,385	2,629,927	2,598,290
Total of Above						
Customer/Connections	67,454	68,439	70,482	72,586	74,754	76,987
kWh	1,091,642,390	1,106,471,443	1,127,632,379	1,147,905,212	1,166,079,671	1,185,641,599
kW from applicable classes	1,137,326	1,177,515	1,195,735	1,218,716	1,240,628	1,263,762
Total from Model		1.5%	3.0%	3.0%	3.0%	3.0%
Customer/Connections	67,454	68,439	70,482	72,586	74,754	76,987
kWh	1,091,642,390	1,106,471,443	1,127,632,379	1,147,905,212	1,166,079,671	1,185,641,599
kW from applicable classes	1,137,326	1,177,515	1,195,735	1,218,716	1,240,628	1,263,762
Check should all be zero						
Customer/Connections	0	0	0	0	0	0
kWh	0	0	0	0	0	0
kW from applicable classes	0	0	0	0	0	0

Appendix 2-H
Other Operating Revenue

USoA	USoA Description	2011 Actual	2011 Actual[2]	2012 Board Approved	2012 Actual	2013 Actual	Bridge Year 2014	Test Year 2015	Test Year 2016	Test Year 2017	Test Year 2018	Test Year 2019
	Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	748,076	748,076	940,286	828,161	817,279	788,337	810,965	834,340	858,487	883,432	909,201
4225	Late Payment Charges	285,613	285,613	279,117	282,631	266,827	280,973	290,256	299,847	309,754	319,989	330,562
4080	SSS Admin Fees	138,402	138,402	133,400	141,981	147,901	150,861	158,568	164,872	172,185	179,242	186,125
4084	Service Trans. Requests	1,506	1,506	3,563	1,725	1,324	1,324	1,326	1,327	1,328	1,330	1,331
4210	Rent from Electric Property	148,782	148,782	150,320	200,944	179,439	176,388	176,388	176,388	176,388	176,388	176,388
4325	Revenues from Merchandise, Jobbing, Etc.	3,724,117	3,724,117	925,000	259,024	182,808	1,388,670	1,388,670	1,388,670	1,388,670	1,388,670	1,388,670
4330	Expenses of Merchandising, Jobbing, Etc	(3,718,609)	(3,718,609)	(925,000)	(233,462)	(174,759)	(1,375,610)	(1,375,610)	(1,375,610)	(1,375,610)	(1,375,610)	(1,375,610)
4355	Gain on Disposition of Utility/Other Property	141,000	141,000	0	(78,877)	5,283	0	0	0	0	0	0
4360	Loss on Disposition of Utility/Other Property	0	0	0	0	(213,702)	(302,875)	(396,446)	(265,096)	(182,214)	(403,265)	(381,240)
4375	Revenues from Non-Utility Operations	1,123,018	1,123,018	10,000	1,077,322	2,756,926	2,376,719	2,376,719	2,376,719	2,376,719	2,376,719	2,376,719
4380	Expenses of Non-Utility Operations	(909,570)	(909,570)	0	(719,442)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)
4390	Miscellaneous Non-Operating Income	150,206	150,206	91,000	107,253	182,428	146,629	146,629	146,629	146,629	146,629	146,629
4405	Interest and Dividend Income	312,474	312,474	184,371	162,774	152,039	128,000	128,000	128,000	128,000	128,000	128,000
Specific Service Charges		748,076	748,076	940,286	828,161	817,279	788,337	810,965	834,340	858,487	883,432	909,201
Late Payment Charges		285,613	285,613	279,117	282,631	266,827	280,973	290,256	299,847	309,754	319,989	330,562
Other Distribution Revenues		288,690	288,690	287,283	344,650	328,665	328,573	336,282	342,587	349,902	356,960	363,844
Other Income and Expenses		822,636	822,636	285,371	574,593	521,878	(7,612)	(101,184)	30,166	113,049	(108,002)	(85,977)
Total		2,145,015	2,145,015	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

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

Account 4235 - Specific Service Charges

	2011 Actual	2011 Actual[2]	2012 Board Approved	2012 Actual	2013 Actual	Bridge Year 2014	Test Year 2015	Test Year 2016	Test Year 2017	Test Year 2018	Test Year 2019
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Collection Charge	295,202	295,202	416,500	355,938	366,650	342,451	353,766	365,455	377,531	390,005	402,891
Set-up Charge	229,260	229,260	246,280	219,060	237,990	230,919	238,549	246,431	254,574	262,985	271,675
Reconnect Charge	93,715	93,715	99,500	91,133	85,598	90,995	94,002	97,108	100,317	103,631	107,055
Credit Check Charge	7,552	7,552	8,900	6,738	6,705	7,064	7,297	7,539	7,788	8,045	8,311
NSF Charge	12,335	12,335	16,000	10,420	6,679	9,903	10,231	10,569	10,918	11,279	11,651
Enhancement Revenue	28,120	28,120	11,000	62,934	48,958	46,671	46,671	46,671	46,671	46,671	46,671
Retail Fixed & Variable charges	77,386	77,386	78,900	77,067	62,839	56,555	56,555	56,555	56,555	56,555	56,555
Other	4,506	4,506	63,206	4,871	1,861	3,778	3,893	4,012	4,135	4,261	4,392
Total	748,076	748,076	940,286	828,161	817,279	788,337	810,965	834,340	858,487	883,432	909,201
							2.9%	2.9%	2.9%	2.9%	2.9%

Appendix 2-H
Other Operating Revenue

USoA	USoA Description	2011 Actual	2011 Actual[2]	2012 Board	2012 Actual	2013 Actual	Bridge Year	Test Year	Test Year	Test Year	Test Year	Test Year
				Approved			2014	2015	2016	2017	2018	2019
	Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	748,076	748,076	940,286	828,161	817,279	896,305	800,370	812,676	825,232	838,042	851,113
4225	Late Payment Charges	285,613	285,613	279,117	282,631	266,827	261,037	285,909	290,959	296,110	301,366	306,729
4080	SSS Admin Fees	138,402	138,402	133,400	141,981	147,901	152,552	155,053	161,427	168,895	176,055	183,008
4084	Service Trans. Requests	1,506	1,506	3,563	1,725	1,324	1,087	1,326	1,327	1,328	1,330	1,331
4210	Rent from Electric Property	148,782	148,782	150,320	200,944	179,439	181,365	176,388	176,388	176,388	176,388	176,388
4325	Revenues from Merchandise, Jobbing, Etc.	3,724,117	3,724,117	925,000	259,024	182,808	142,836	1,388,670	1,388,670	1,388,670	1,388,670	1,388,670
4330	Expenses of Merchandising, Jobbing, Etc	(3,718,609)	(3,718,609)	(925,000)	(233,462)	(174,759)	(118,844)	(1,375,610)	(1,375,610)	(1,375,610)	(1,375,610)	(1,375,610)
4355	Gain on Disposition of Utility/Other Property	141,000	141,000	0	(78,877)	5,283	(0)	0	0	0	0	0
4360	Loss on Disposition of Utility/Other Property	0	0	0	0	(213,702)	(186,801)	(396,446)	(265,096)	(182,214)	(403,265)	(381,240)
4375	Revenues from Non-Utility Operations	1,123,018	1,123,018	10,000	1,077,322	2,756,926	1,054,470	2,376,719	2,376,719	2,376,719	2,376,719	2,376,719
4380	Expenses of Non-Utility Operations	(909,570)	(909,570)	0	(719,442)	(2,369,144)	(850,787)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)	(2,369,144)
4390	Miscellaneous Non-Operating Income	150,206	150,206	91,000	107,253	182,428	187,459	146,629	146,629	146,629	146,629	146,629
4405	Interest and Dividend Income	312,474	312,474	184,371	162,774	152,039	153,049	128,000	128,000	128,000	128,000	128,000
Specific Service Charges		748,076	748,076	940,286	828,161	817,279	896,305	800,370	812,676	825,232	838,042	851,113
Late Payment Charges		285,613	285,613	279,117	282,631	266,827	261,037	285,909	290,959	296,110	301,366	306,729
Other Distribution Revenues		288,690	288,690	287,283	344,650	328,665	335,003	332,767	339,142	346,611	353,773	360,727
Other Income and Expenses		822,636	822,636	285,371	574,593	521,878	381,381	(101,184)	30,166	113,049	(108,002)	(85,977)
Total		2,145,015	2,145,015	1,792,057	2,030,035	1,934,649	1,873,725	1,317,863	1,472,943	1,581,002	1,385,179	1,432,592

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

Account 4235 - Specific Service Charges

	2011 Actual	2011 Actual[2]	2012 Board	2012 Actual	2013 Actual	Bridge Year	Test Year	Test Year	Test Year	Test Year	Test Year
			Approved			2014	2015	2016	2017	2018	2019
Reporting Basis	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Collection Charge	42,932	42,932	49,500	36,608	43,012	39,936	41,959	42,700	43,456	44,227	45,014
Set-up Charge	106,045	106,045	109,230	104,158	97,693	90,150	105,416	107,278	109,177	111,115	113,092
Reconnect Charge	15,883	15,883	21,500	16,217	11,890	10,267	15,061	15,327	15,598	15,875	16,158
Credit Check Charge	257,212	257,212	371,750	323,362	324,748	451,958	309,962	315,436	321,020	326,719	332,533
NSF Charge	1,824	1,824	2,000	1,894	1,342	1,188	1,732	1,763	1,794	1,826	1,859
Enhancement Revenue	35	35	150	40	88	0	56	57	58	59	60
Retail Fixed & Variable charges	0	0	58,206	0	0	0	0	0	0	0	0
Other	324,144	324,144	327,950	345,883	338,507	302,805	326,184	330,116	334,128	338,221	342,397
Total	748,076	748,076	940,286	828,161	817,279	896,305	800,370	812,676	825,232	838,042	851,113
							-10.7%	1.5%	1.5%	1.6%	1.6%

Appendix 2-OB
Debt Instruments

A	B	C	D	E	F	G	H	I	J	K	L
				Year	2015						
	Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
54	1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
55	2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
56	3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 219,399	Actual
58											
59	Total							$ 36,968,110	4.24%	$ 1,569,101	

60 *** $15m weighted for year at $6.9m ***

61

62 =I56*(365-I64)/365+I55+I54

63

64 197 Days loan in place for 2015

65 $ 6,904,110 Weighted $ for year

Appendix 2-OB
Debt Instruments

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 219,399	Actual
Total							$ 36,968,110	4.24%	$ 1,569,101	

*** $15m weighted for year at $6.9m ***

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 406,500	Actual
6										
Total							$ 45,064,000	3.90%	$ 1,756,203	

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 406,500	Actual
6	Term Loan 2017	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2017		$ 3,440,814	4.77%	$ 164,127	Deemed Rate
7										
Total							$ 48,504,814	3.96%	$ 1,920,330	

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 406,500	Actual
4	Term Loan 2017	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2017		$ 3,440,814	4.77%	$ 164,127	Deemed Rate
6	Term Loan 2018	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2018		$ 17,158,013	4.77%	$ 818,437	Deemed Rate
Total							$ 65,662,827	4.17%	$ 2,738,767	

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Debenture	OPUC	Affiliated	Fixed Rate	Dec-2005		$ 23,064,000	4.77%	$ 1,100,153	Deemed Rate
2	Term Loan 2012	TD Bank	Third-Party	Fixed Rate	Dec-2012	7	$ 7,000,000	3.57%	$ 249,550	Actual
3	Term Loan 2015	TD Bank	Third-Party	Fixed Rate	Jun-2015	7	$ 15,000,000	2.71%	$ 406,500	Actual
6	Term Loan 2017	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2017		$ 3,440,814	4.77%	$ 164,127	Deemed Rate
7	Term Loan 2018	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2018		$ 17,158,013	4.77%	$ 818,437	Deemed Rate
8	Term Loan 2019	TD Bank (Unfunded)	Third-Party	Fixed Rate	Jan-2019		$ 1,609,181	4.77%	$ 76,758	Deemed Rate
9										
Total							$ 67,272,008	4.19%	$ 2,815,525	

MS. LEA: So as I understand your answer, then, rather than creating a performance contract by taking any metric -- believe me, I am not asking you for a specific metric if that is inappropriate for your company and its size, but the metrics that you already have to produce for the scorecard or something that you have determined for yourself for your capital programs, you're the ones that know what is best for you. So I am not trying to go outside of that.

But as I understand your answer you're saying, rather than having targets, specific targets, on those metrics and a kind of a performance contract, you're proposing, instead, an incentive which acts -- which will incent you to exceed the target that you have set for yourself and is embedded in your costs.

Do I understand your answer correctly?

MR. LABRICCIOSA: I think -- yes. I think, yes, the short answer is yes.

When you say "embedded in your costs", our estimates are based on where we are at today. And so the stretch factor, we didn't actually put a target number there, but through the incentive aspect of it, we are suggesting that, you know, internally how we manage the company, we are going to set a target for ourselves to manage it better than those estimates.

And those estimates are informed, again, externally by an external agency as the benchmark to the outside of the company. They've put together an estimate plan that is consistent with where we put our estimates at, and that's the sort of benchmarking to the outside. And then how we perform and we intend to perform to actually deliver those projects under those estimates, that's kind of our target setting.

So we didn't set it as a per unit measure or a per project measure. It is an in aggregate project -- aggregate portfolio delivery measure which is driven by, again, the outside growth and the focussed investment that is really driving this application.

MS. LEA: And do you think it would be inappropriate or would you resist the idea of creating more of a performance contract approach with specific measures on whatever metric you decide is appropriate, rather than what you have put forward?

MR. LABRICCIOSA: I think at the surface I would have to say yes. I would resist it somewhat, because there are a lot of unknowns in that.

Again, as we move forward in this area, again, not a lot of things are nailed down. So there's a lot of risk when you start detailing out specifics. I was describing -

MS. LEA: I'm sorry, what do you mean by not a lot of things are nailed down? What things? What risks? Please be more specific.

MR. LABRICCIOSA: Sure. The rules of the RRFE aren't quite figured out. Yes, you referenced decisions that have already been delivered and asked questions around, you know, well, could our application have that specific metric

Appendix 2-AA
Capital Projects Table ($'000s)

Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	2015 - 2019
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
					Actual						
System Access											
Subdivision Expansions	918	1,300	1,816	1,820	2,171	1,075	1,125	1,150	1,180	1,215	
Service connections/requests	430	366	150	160	169	120	110	100	100	100	
Service/Expansion Contributions	(2,034)	(931)	(1,271)	(1,459)	(2,143)	(650)	(675)	(690)	(705)	(730)	
Hwy 407 Extension - Plant relocation					432	4,510	700				
Hwy 407 contribution					2	(3,580)	(400)				
Durham Region - Plant relocation	0	447	347	450	98	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	47	680	595	470	460	470	
City of Oshawa Contribution				(90)	(117)	(175)	(145)	(120)	(110)	(120)	
Metering service connections	99	6,780	586	573	528	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	
Long Term load transfers (LTLT)				781	319						
MoE approved Micro Grid Project					0	110	45				
System Access Total	(726)	7,982	1,628	2,343	1,506	4,084	2,685	2,475	2,340	2,350	13,934
System Renewal											
O/H Rebuilds	2,288	2,215	1,390	2,407	2,885	2,410	2,455	2,055	2,510	2,117	
U/G Rebuilds	684	1,416	1,013	1,789	1,392	1,133	1,007	1,087	921	904	
Station Rebuilds	466	2,758	3,879	925	2,847	510	640	500	500	1,000	
Station Rebuilds (MS14 Switchgear in WIP end 2014)					(1,060)	1,060					
Reactive/emergency Plant Replacement	1,199	650	880	850	1,034	830	830	830	830	830	
System Renewal Total	4,637	7,039	7,162	5,971	7,098	5,943	4,932	4,472	4,761	4,851	24,959
System Services											
Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension				1,903	1,169						
Thorton TS Capacity - HONI Contributions											
Wilson TS Capacity - HONI Contributions											
TS Capacity - HONI Contributions						1,350		5,400	6,750		13,750
MS9 - 44kV/13.8kV Substation									7,000		14,500
MS9 Proposed OH distribution feeders									4,000	3,500	
Neutral Reactors						450	1,050				
Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements					397	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	1,566	2,418	1,380	5,820	18,395	4,050	3,813
General Plant											
Fleet	245	585	1,438	17	153	420	415	440	190	170	
Total Facilities Leasehold Improvements	36	354	174	17	76	225	50	50	50	50	
Major Tools and Equipment	152	110	110	44	54	50	50	50	50	50	
Outage Management System Implementation including Interface with SCADA, GIS, CIS, AMI, IVR	0	0	0	0	70	850	0	0	0	0	
Mobile Work force					0		50	50			
ODS Replacement due to enhanced operational requirements not available with existing ODS					0		400				
GIS Enhancements for operational needs including OMS					66		60	60	60	60	
MAS Enhancements for operational needs					13		25	25	50	50	
ODS/CIS Enhancements for operational needs									50	50	
Office IT Capital Expenditure	64	165	167	270	54	130	130	80	280	80	
General Plant Total	497	1,214	1,889	348	486	1,675	1,180	755	730	510	4,850
Miscellaneous (2018 $'s are MS9 land)	278	262	413	182	1				159		
Total	4,686	16,497	11,092	10,747	10,657	14,120	10,177	13,522	26,385	11,761	75,965

$500,000 compared to 2012 Actual, with primarily inflationary increases projected thereafter.

The reasoning behind the addition of 5.8 FTE's to the 2012 Board-Approved number, and the temporary spike in cost due to succession planning, are explained in the 'Program And Function Overview' section earlier in this chapter. Table 4-23 below provides a summary by function of the FTE changes, separately identifying movements by retirements, replacements, new hires and overlaps.

TABLE 4-23 –ANALYSIS OF FTE MOVEMENTS 2012 BOARD-APPROVED TO 2019 TEST YEAR

	2012 Approved	2012 Actual	2013 Actual	2014 Bridge	2015 Test	2016 Test	2017 Test	2018 Test	2019 Test	2012 App to 2019	2014 to 2019
Opening FTE's	**75.0**	**69.0**	**73.8**	**73.9**	**74.9**	**80.4**	**84.6**	**84.4**	**83.1**	**75.0**	**73.9**
Retirements											
Grid Construction & Maintenance	-	-	-	-	(1.3)	(1.7)	(0.5)	(0.8)	(1.8)	(6.0)	(6.0)
Technical Design	-	-	-	-	-	-	-	(0.5)	(0.5)	(1.0)	(1.0)
Stores	-	-	-	-	-	(0.3)	(0.7)	-	-	(1.0)	(1.0)
Retirements sub-total	**0.0**	**0.0**	**0.0**	**0.0**	**(1.3)**	**(2.0)**	**(1.2)**	**(1.3)**	**(2.3)**	**(8.0)**	**(8.0)**
Replacements											
Grid Construction & Maintenance	-	-	-	0.7	1.3	3.0	1.0	-	-	6.0	6.0
Technical Design	-	-	-	-	-	1.0	-	-	-	1.0	1.0
Engineering	-	-	-	-	-	0.7	0.3	-	-	1.0	1.0
Replacements sub-total	**0.0**	**0.0**	**0.0**	**0.7**	**1.3**	**4.7**	**1.3**	**0.0**	**0.0**	**8.0**	**8.0**
New Hires											
Grid Construction & Maintenance	-	1.6	-	-	1.0	-	-	-	-	1.0	1.0
Customer Service	-	1.0	-	-	-	1.0	-	-	-	1.0	1.0
IT	-	-	-	0.4	1.0	-	-	-	-	0.4	1.4
Technical Design	-	-	-	0.4	1.0	-	-	-	-	1.4	1.4
Operations Management	-	-	-	0.5	0.5	-	-	-	-	1.0	1.0
Metering	-	-	-	-	0.5	0.5	-	-	-	1.0	1.0
New Hires sub-total	**0.0**	**2.6**	**0.0**	**1.3**	**4.0**	**1.5**	**0.0**	**0.0**	**0.0**	**5.8**	**6.8**
Overlaps	**0.0**	**2.2**	**0.1**	(1.0)	1.4	(0.1)	(0.3)	-	-	0.0	0.1
Closing FTE's	**75.0**	**73.8**	**73.9**	**74.9**	**80.4**	**84.6**	**84.4**	**83.1**	**80.8**	**80.8**	**80.8**

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	2011 Actuals	Last Rebasing Year (2012 Approved)	2013 Actuals	2014 Bridge Year (Actual)	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Opening Balance	$9,112,991	$11,480,220	$11,240,450	$11,210,095	$11,207,896	$12,239,749	$12,724,333	$13,020,525	$13,233,832
Labour inflation (including progression)	$168,800	$0	$253,924	$161,417	$126,181	$168,293	$173,598	$176,230	$187,280
Succession Planning (Retirements)	$0	$0	$0	$0	$93,752	$165,561	$23,728	$(34,302)	$(179,869)
New Hires	$48,233	$(69,723)	$0	$54,328	$179,173	$107,811	$0	$0	$0
Overlap re Leavers/ Replacements	$218,610	$(32,084)	$5,444	$(112,682)	$110,732	$0	$0	$0	$0
Overtime re Dec 2012 Ice Storm			$184,609	$(184,609)					
Labour Other (including overtime)	$(50,732)	$(1,626)	$36,733	$(42,780)	$170,517	$4,289	$4,386	$4,485	$4,585
Labour sub-total	**$384,911**	**$(103,433)**	**$480,709**	**$(124,326)**	**$680,355**	**$445,955**	**$201,712**	**$146,413**	**$11,997**
Benefits	$225,216	$6,308	$(304,935)	$(5,429)	$35,396	$87,333	$58,950	$30,680	$25,099
Subcontractors	$8,925	$(29,049)	$23,961	$(214,881)	$232,870	$1,803	$33,965	$34,644	$35,337
Legal & Consulting Fees	$(216,255)	$15,783	$43,534	$(187,504)	$130,941	$(13,994)	$6,296	$6,426	$6,558
Provision for Doubtful Accounts	$108,860	$(140,092)	$124,950	$33,137	$(14,550)	$9,433	$10,103	$10,315	$10,531
Capital Taxes	$(61,959)	$0	$0	$0	$0	$0	$0	$0	$0
Materials (including Inventory Writedowns)	$(7,328)	$144,270	$(129,507)	$38,059	$(21,410)	$3,686	$3,948	$4,031	$4,115
Insurance	$20,701	$(79,493)	$57,004	$(31,813)	$9,332	$5,920	$6,341	$6,474	$6,610
Allocations to Capital and Jobbing Work	$324,165	$13,690	$(319,978)	$271,390	$(216,130)	$(119,064)	$(96,180)	$(98,344)	$(100,557)
Regulatory Fees		$10,361	$(906)	$(17,235)	$165,054	$4,483	$4,802	$4,902	$5,005
IT Licensing costs (mainly Smart Meters)		$(30,802)	$24,013	$30,367	$19,755	$3,842	$4,115	$4,202	$4,290
SR&ED ITC's credited to OM&A			$(111,362)	$66,362					
Smart Meter OM&A Variance Ac Release	$392,825								
Other	$29,739	$(47,312)	$82,161	$139,673	$10,238	$55,187	$62,141	$63,564	$64,624
Closing Balance	$10,322,790	$11,240,450	$11,210,095	$11,207,896	$12,239,749	$12,724,333	$13,020,525	$13,233,832	$13,307,442