Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0147

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 Midland Power Utility Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

Before: Marika Hare
Presiding Member

Ellen Fry
Member

DECISION AND ORDER
January 17, 2013

Midland Power Utility Corporation ("Midland") filed an application with the Ontario Energy Board (the "Board"), received on August 31, 2012, under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Midland charges for electricity distribution, to be effective May 1, 2013. Midland provided an update on October 19, 2012 to certain sections of the application. The Board assigned File Number EB-2012-0147 to the application.

The Board issued a Notice of Application and Hearing dated September 17, 2012. The Board issued Procedural Order No. 1 on October 12, 2012 which among other things, scheduled interrogatories and granted intervenor status to the School Energy Coalition ("SEC") and the Vulnerable Energy Consumers Coalition ("VECC") in this proceeding. The Board also determined that SEC and VECC were eligible to apply for an award of costs under the Board's *Practice and Direction on Cost Awards*.

On November 21, 2012, the Board issued Procedural Order No. 2 providing for intervenors or Board staff who wish to ask questions for the purpose of clarifying the information in the interrogatory responses filed by Midland to file supplementary written interrogatories. Additionally, the Board ordered a Settlement Conference to be convened on December 6, 2012 and to be continued if necessary on December 7, 2012. The Board ordered that any Settlement Agreement arising from the Settlement Conference be filed on or before December 21, 2012.

On December 21, 2012, Midland filed a proposed Settlement Agreement with the Board. Midland, SEC and VECC are the parties (collectively, the “Parties”) to the proposed Settlement Agreement. The proposed Settlement Agreement is included as Appendix A to this Decision and Order and represents a comprehensive Settlement Agreement with no unsettled matters.

On January 4, 2013, the Board requested clarification from the applicant and the other parties to the settlement as to why the revenue-to-cost ratios agreed upon in the proposed Settlement Agreement are at the extreme end of the Board’s target ranges for all rate classes except the GS<50 kW class, particularly since the original application had proposed ratios closer to unity. Responses were provided by SEC on January 7, 2013, followed by VECC and Midland, on behalf of all parties to the Settlement Agreement, on January 8, 2013. The letter from VECC discussed the fact that the Settlement Agreement was the result of the intertwining of a large number of complex issues and varying positions of the parties. The ratios, VECC believed however, were consistent with the Board’s policies as set out in the Board’s EB-2010-0219 Report. SEC’s letter noted a perceived inconsistency with the Board’s policy in a recent Decision and welcomed guidance from the Board as to the Board’s policy. Midland’s letter noted its understanding that the proposed revenue-to-cost ratios in the Proposed Settlement Agreement are in accordance with what Midland understands to be the Board’s practice and policy with respect to revenue-to-cost ratios.

Findings

The Board is concerned with one aspect of the proposed Settlement Agreement, namely the fact that the revenue-to-cost ratios for all rate classes, with the exception of GS < 50 kW, were at the extreme end of the Board’s target ranges. Midland’s original application stated that it was seeking to move the ratios closer to unity in order to minimize cross-subsidization, which is an objective that the Board supports.

The responses to the Board's request for clarification did not address this point, which may be as a result of caution about disclosing confidential details with respect to concessions made during negotiations in the Settlement Conference. However, the Board accepts the cost allocations included in the proposed Settlement Agreement as these ratios are within the Board's target ranges. Accordingly the Board accepts the proposed Settlement Agreement in its entirety and further, finds the cost and rate consequences to be reasonable.

The Board commends the parties on achieving settlement of all matters.

THE BOARD ORDERS THAT:

1. Midland shall file with the Board, and shall also serve on the intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges, to be effective May 1, 2013 and supporting documentation that has not already been filed as part of the Settlement Agreement reflecting the Board's findings in this Decision and Order within **7 days** of the date of this Decision and Order.

2. Intervenors and Board staff shall file any comments on the Draft Rate Order with the Board and serve on Midland within **7 days** of the date that Midland files the Draft Rate Order.

3. Midland shall file with the Board and serve on intervenors responses to any comments on its Draft Rate Order within **4 days** of the date of receipt of Board staff and intervenor comments.

4. Intervenors shall file with the Board and forward to Midland their respective cost claims within **7 days** from the date of issuance of the final Rate Order.

5. Midland shall file with the Board and forward to intervenors any objections to the claimed costs within **14 days** from the date of issuance of the final Rate Order.

6. Intervenors shall file with the Board and forward to Midland any responses to any objections for cost claims within **21 days** of the date of issuance of the final Rate Order.

7. Midland shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2012-0147, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's *Practice Directions on Cost Awards*

All communications should be directed to the attention of the Board Secretary and be received no later than 4:45 p.m. on the required date.

DATED at Toronto, January 17, 2013

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX “A” TO

DECISION AND ORDER

BOARD FILE NO.: EB-2012-0147

DATED January 17, 2013

EB-2012-0147

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 Midland Power Utility Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

MIDLAND POWER UTILITY CORPORATION ("Midland")

PROPOSED SETTLEMENT AGREEMENT

FILED: DECEMBER 21, 2012

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MIDLAND POWER UTILITY CORPORATION ("Midland")
PROPOSED SETTLEMENT AGREEMENT
FILED: DECEMBER 21, 2012

INTRODUCTION:

Midland carries on the business of distributing electricity within the Town of Midland as described in its distribution licence.

Midland filed an application with the Ontario Energy Board (the "Board") on August 31, 2012 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B), seeking approval for changes to the rates that Midland charges for electricity distribution, to be effective May 1, 2013 (the "Application"). The Board assigned the Application File Number EB-2012-0147.

Two parties requested and were granted intervenor status: the Vulnerable Energy Consumers' Coalition ("VECC"), and School Energy Coalition ("SEC"). These parties are referred to collectively as the "Intervenors".

In Procedural Order No. 1, issued on October 12, 2012, the Board approved the Intervenors in this proceeding, set dates for interrogatories and interrogatory responses and made its determination regarding the cost eligibility of the Intervenors.

In Procedural Order No 2, issued on November 21, 2012, the Board set dates for Supplemental Interrogatories from Intervenors; dates for a Settlement Conference (December 6, 2012, continuing December 7, 2012 if necessary); and, the filing of any Settlement Proposal arising out of the Settlement Conference (December 21, 2012). There is no Board-approved Issues List for this proceeding.

The evidence in this proceeding (referred to herein as the "Evidence") consists of the Application, including updates to the Application, and Midland's responses to the initial and supplemental interrogatories. The Appendices to this Settlement Agreement (the "Agreement") are also included in the Evidence. The Settlement Conference was duly convened in accordance with the Procedural Order No. 2, with Mr. Chris Haussmann as facilitator. The Settlement Conference was held on December 6, 2012.

Midland and the following Intervenors participated in the Settlement Conference:

- SEC; and
- VECC.

Midland and the Intervenors are collectively referred to below as the "Parties".

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Board's *Settlement Conference Guidelines* (the "Guidelines"). The Parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Agreement.

The role adopted by Board Staff in the Settlement Conference is set out in page 5 of the Guidelines. Although Board staff is not a party to this Agreement, as noted in the Guidelines, Board staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

A COMPLETE SETTLEMENT HAS BEEN REACHED ON ALL ISSUES IN THIS PROCEEDING:

The Parties are pleased to advise the Board that a complete settlement has been reached on all issues in this proceeding. This document comprises the Proposed Settlement Agreement and it is presented jointly by Midland, SEC and VECC to the Board. It identifies the settled matters and contains such references to the Evidence as are necessary to assist the Board in understanding the Agreement. The Parties confirm the Evidence filed to date in respect of each settled issue, as supplemented in some instances by additional information recorded in this Agreement, supports the settlement of the matters identified in this Agreement. In addition, the Parties agree the Evidence, supplemented where necessary by the additional information appended to this Agreement, contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached by the Parties.

The Parties explicitly request the Board consider and accept this Proposed Settlement Agreement as a package. None of the matters in respect of which a settlement has been reached is severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Agreement. The distinct issues addressed in this proposal are intricately interrelated and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Agreement in its entirety, then there is no Agreement unless the Parties agree those portions of the Agreement the Board does accept may continue as a valid settlement.

It is further acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the *Board's Rules of Practice and Procedure*.

It is also agreed this Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Agreement. However, none of the Parties will, in any subsequent proceeding, take the position the resolution therein of any issue settled in this Agreement, if contrary to the terms of this Agreement, should be applicable for all or any part of the 2013 Test Year.

References to the Evidence supporting this Agreement on each issue are set out in each section of the Agreement. The Appendices to the Agreement provide further evidentiary support. The Parties agree this Agreement and the Appendices form part of the record in EB-2012-0147. The Appendices were prepared by the Applicant. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement. Appendix I to this Agreement – Proposed Schedule of 2013 Tariff of Rates and Charges (Updated) – is a proposed schedule of Rates and Charges. If the Board approves the Agreement Midland expects to use the information in Appendix I as the basis for its draft Rate Order following Board approval of this Agreement.

The Parties believe the Agreement represents a balanced proposal that protects the interests of Midland's customers, employees and shareholder and promotes economic efficiency and cost effectiveness. It also provides the resources which will allow Midland to manage its assets so that the highest standards of performance are achieved and customers' expectations for the safe and reliable delivery of electricity at reasonable prices are met.

The Parties have agreed the effective date of the rates resulting from this proposed Agreement is May 1, 2013 (referred to below as the "Effective Date").

ORGANIZATION AND SUMMARY OF THE SETTLEMENT AGREEMENT:

As noted above, there is no Board-approved Issues List for this proceeding. For the purposes of organizing this Agreement, the Parties have used the Issues List in the Guelph Hydro Electric Systems Inc. proceeding (EB-2011-0123) as a guide, as that Issues List addresses all of the revenue requirement components, load forecast, deferral and variance account dispositions, cost allocation and rate design and other issues that are also relevant to determining Midland's 2013 distribution rates.

The following Appendices accompany this Settlement Agreement:

Appendix A – Summary of Significant Changes (Updated)
Appendix B – Continuity Tables
Appendix C – Cost of Power Calculation (Updated)
Appendix D – 2013 Customer Load Forecast (Updated)
Appendix E – 2013 Other Revenue
Appendix F – 2013 PILS (Updated)
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Appendix M – Throughput Revenue (Updated)

UNSETTLED MATTERS:

There are no unsettled matters in this proceeding.

OVERVIEW OF THE SETTLED MATTERS:

This Agreement will allow Midland to continue to make the necessary investments in maintenance and operation expenditures as well as capital investments to maintain the safety and reliability of the electricity distribution service that it provides.

This Agreement will also allow Midland to: maintain current capital investment levels and, where required, appropriately increase capital investment levels in infrastructure to ensure a reliable distribution system; manage current and future staffing levels, skills and training to ensure regulatory compliance with Codes and Regulations; promote conservation programs including the Ministry of Energy directives as a condition of Midland's distribution licence; and continue to provide the high level of customer service that Midland's customers have come to expect.

The Parties agree no rate classes face bill impacts that require mitigation efforts as a result of this agreement.

In this Agreement, except where otherwise expressly stated, all dollar figures are calculated and expressed using Canadian Generally Accepted Accounting Principles ("CGAAP"). For the purposes of settlement, the Parties acknowledge that Midland is not converting to International Financial Reporting Standards ("IFRS") in the 2013 Test Year and will remain on CGAAP until required by the Accounting Standards Board (the "AcSB") to move to IFRS. However, Midland will comply with the Board's letter titled "Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies 2013" dated July 17, 2012. Midland will implement the regulatory accounting changes for depreciation expense and capitalization policies effective January 1, 2013. As a result of these changes, Midland expects that there will be no material adjustments when Midland ultimately converts to IFRS.

In Midland's initial evidence a Service Revenue Requirement for the 2013 Test Year was $4,065,446 which included a Base Revenue Requirement of $3,801,842 and Revenue Offsets of $263,604 with a resulting Revenue Deficiency of $228,213. Through the interrogatory and settlement process, Midland made changes to the Service Revenue Requirement as shown in Settlement Table #1: Service Revenue Requirement as follows:

Settlement Table #1: Service Revenue Requirement

		COS Application Filing	Settlement Submission	Difference
Service Revenue Requirement	A	$4,065,446	$3,954,361	($111,085)
Revenue OffSets	B	($263,604)	($291,800)	($28,196)
Base Revenue Requirement	C = A+B	$3,801,842	$3,662,561	($139,281)
Revenue at Existing Rates	D	$3,837,233	$3,888,258	$51,025
Revenue Deficiency	E = A - D	$228,213	$66,102	($162,110)

The revised Service Revenue Requirement for the 2013 Test Year is $3,954,361 which reflects the updated cost of capital parameters (ROE and Deemed Short Term Debt rate) issued by the Board on November 15, 2012 applicable to applications for rebasing effective May 1, 2013. The long term debt rate was agreed to be 3.61%, for the purpose of settlement. Compared to the forecast 2013 revenue at current rates of $3,888,258, the revised Service Revenue Requirement represents a deficiency of $66,102 which is $162,110 lower than the revenue deficiency of $228,213 set out in Midland's COS Application filing.

Through the settlement process, Midland has agreed to certain adjustments from its original 2013 Application and subsequent updated Evidence. Any such changes are described in the sections below.

1. GENERAL

1.1 Has Midland responded appropriately to all relevant Board directions from previous proceedings?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 1, Tab 1, Schedule 15

For the purposes of settlement the Parties accept the Evidence of the Applicant that there were no outstanding obligations or orders from previous Board decisions.

1.2 Are Midland's economic and business planning assumptions for 2013 appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 1, Tab 2, Schedule 2

For the purposes of settlement, the Parties accept Midland's economic and business planning assumptions for 2013.

1.3 Is service quality, based on the Board specified performance assumptions for 2013, appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 3, Schedule 5

For the purposes of settlement, the Parties accept Midland's evidence with respect to the acceptability of its service quality, based on the Board-specified indicators.

1.4 What is the appropriate effective date for any new rates flowing from this Application? If that effective date is prior to the date new rates are actually implemented, what adjustments should be implemented to reflect the sufficiency or deficiency during the period from effective date to implementation date?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 1, Tab 1, Schedule 2

For the purpose of settlement, the Parties accept that the appropriate effective date of the new rates flowing from this Application is May 1, 2013.

2. RATE BASE

2.1 Is the proposed rate base for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 2
Board Staff IR #6, #7, #8
SEC IR #9, #10, #11, #12
VECC IR #1, #2, #3, #4, #5, #6
SEC Supplemental IR #4
Settlement Agreement, Section 3.2, Section 3.3, Section 4.1, Appendix C

For the purposes of settlement, the Parties have agreed that Midland's Rate Base is $15,976,736 for the 2013 Test Year under CGAAP. A full calculation of this agreed Rate Base is set out later in this section in Settlement Table #2: Rate Base. The 2013 capital expenditures and amortization expense were accepted as proposed in Midland's interrogatory responses.

The revised Rate Base value reflects the following changes to the working capital allowance:

- With respect to Cost of Power, the Parties have agreed for the purposes of settlement to accept The Load Forecast in Midland's Initial Application <u>except</u> for the following:
  - The CDM variable has been reduced from the gross variable to the net variable of 2,395,867 kWh;
  - The load attributed to GS>50kW class has been adjusted to 120,000,000 kWh;
  - CDM Activity variable was adjusted to reflect the final 2011 CDM results;
  - RPP rates were updated to reflect the change in rates effective November 1, 2012;
  - The Smart Meter Entity charge was removed from the Working Capital calculation;

  The Cost of Power was therefore increased from $19,811,587 to $20,036,663 as a result of these changes.

  Please see Appendix C for the detailed Cost of Power calculation.

- The Parties have agreed that the 2013 OM&A for the Test Year, including property taxes should be $2,350,385 (CGAAP), a decrease of $195,933 from $2,546,318 in the original Application. OM&A expenses are discussed in further detail under item 4.1.

The changes to working capital produces an increase in working capital base of $29,143 and an increase to working capital of $3,789 over the original Application filing, as set out in Settlement Table #3: Allowance for Working Capital, under Section 2.2 below.

Agreed upon adjustments to Midland's proposed Overall Rate Base under CGAAP is set out in Settlement Table #2: Rate Base, below.

Settlement Table #2: Rate Base

	Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
Gross Fixed Assets (average)	$25,591,525	$448,097	$26,039,622	$0	$26,039,622
Accumulated Depreciation (average)	($12,457,078)	($516,124)	($12,973,203)	$0	($12,973,203)
Net Fixed Assets (average)	$13,134,447	($68,028)	$13,066,419	$0	$13,066,419
Allowance for Working Capital	$2,906,528	$12,402	$2,918,929	($8,613)	$2,910,316
Total Rate Base	**$16,040,975**	**($55,626)**	**$15,985,349**	**($8,613)**	**$15,976,736**

2.2 Is the working capital allowance for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 2, Tab 4
VECC IR #14
Settlement Agreement, Section 2.1

For the purposes of settlement, the Parties agree to the following Working Capital Allowance calculated based on 13% of the OM&A expenses of $2,320,000 (CGAAP), plus property tax of $30,385, and Cost of Power of $20,036,663. As discussed in Section 2.1 and this section, the Parties have agreed the adjustments shown below in Settlement Table #3: Allowance for Working Capital, reflecting the settled matters, will be made to Midland's Working Capital Allowance calculation:

Settlement Table #3: Allowance for Working Capital

	Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
OM&A Expenses	$2,515,933	($38,809)	$2,477,124	($157,124)	$2,320,000
Property Taxes	$30,385		$30,385	$0	$30,385
Cost of Power	$19,811,587	$134,207	$19,945,794	$90,869	$20,036,663
Workign Capital Base	$22,357,905	$95,398	$22,453,303	($66,255)	$22,387,048
Working Capital Rate%	13.00%		13.00%		13.00%
Working Capital Allowance	**$2,906,528**	**$12,402**	**$2,918,929**	**($8,613)**	**$2,910,316**

2.3 Is the capital expenditure forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 2, Tabs 2-6
Board Staff IR #9, #10
SEC IR #9, #10, #11, #12
VECC IR #1, #2, #5, #6
SEC Supplemental IR #4

For the purposes of settlement, the Parties have accepted net capital expenditures of $1,750,900 amended from Midland's original Application of $1,795,900, as shown in Midland's response to VECC IR #6.

2.4 Is the capitalization policy and allocation procedure appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 2, Tab 3, Schedule 4

For the purposes of settlement, the Parties have accepted Midland's capitalization policy as it was set out on Exhibit 2, Tab 3, Schedule 4 of the original Application.

3. LOAD FORECAST AND OPERATING REVENUE

3.1 Is the load forecast methodology including weather normalization appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application, Exhibit 3, Tab 2
Board Staff IR #11, #12, #13, #14
VECC IR #7, #8, #9, #10, #11, #12, #13, #14
VECC Supplemental IR #8(c)

For the purposes of settlement, the Parties accept Midland's load forecast methodology, including weather normalization as modified through the settlement process as follows:

- The Parties did not agree on the load forecast methodology, specifically the use of the CDM variable with a coefficient of (7.54), but the Parties did agree with the CDM results, and so have accepted the load forecast methodology since the CDM issue is not material to the results; and

- Changes to the load forecast for the purposes of settlement, included the CDM manual adjustment from gross to net based on the 2011 Final OPA program results (detailed in Section 3.3 below), and an increase in the GS>50 kW class to 120,000,000 kWh (detailed in Section 3.2 below).

This results in a billed consumption forecast of 193,971,864 kWh and 296,300 kW in the 2013 Test Year. The accepted CDM adjustment for 2012 and 2013 CDM programs is 2,395,867 kWh and 419 kW for the 2013 Test Year. This does not include the adjustment for the 2011 programs as the 2011 programs are already reflected in the load forecast.

3.2 Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application, Exhibit 3, Tab 2 Board Staff IR #11, #12, #13, #14 VECC IR #7, #8, #9, #10, #11, #12, #13, #14 VECC Supplemental IR #8(c) Settlement Agreement, Appendix A, Appendix D

For the purposes of settlement, the Parties agree with Midland's customers/connections and load forecasts (both kWh and kW) for the 2013 test year. Through the settlement process Midland modified the GS>50 kW customer class and the movement of the CDM variable from gross to net consumption to exclude the free ridership. The change agreed to by all Parties was to increase the GS>50 kW consumption to 120,000,000 kWh and demand to 292,641 kW. The Parties also agreed to reduce the number of GS>50 kW customers from 113 to 112. The changes made to the consumption for all classes reflect the CDM variable adjustment from gross to net consumption. Settlement Table #4: Load Forecast, details the above change which resulted in a $10,680 reduction in Midland's Revenue Deficiency and an increase in Rate Base of $20,596 based on the progression of changes that are detailed in Appendix A.

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Settlement Table #4: Load Forecast

		Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
Residential	Customers	6,231	0	6,231	0	6,231
	kWh	49,023,071	328,074	49,351,145	889,865	50,241,010
GS<50	Customers	755	0	755	0	755
	kWh	23,098,239	154,579	23,252,818	-1,280,169	21,972,649
GS>50	Customers	113	0	113	-1	112
	kWh	117,836,449	280,369	118,116,818	1,883,182	120,000,000
	kW	287,241	700	287,941	4,700	292,641
Streetlights	Connections	2,072	0	2,072	0	2,072
	kWh	1,314,588	-2,383	1,312,204	26,149	1,338,353
	kW	3,595	-7	3,588	72	3,660
USL	Customers	12	0	12	0	12
	kWh	412,397	-748	411,649	8,203	419,852
Totals	**Customers/ Connections**	**9,182**	**0**	**9,182**	**-1**	**9,181**
	kWh	**191,684,743**	**759,892**	**192,444,635**	**1,527,229**	**193,971,864**
	kW	**290,836**	**693**	**291,529**	**4,771**	**296,300**

3.3 Is the impact of CDM appropriately reflected in the load forecast?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application, Exhibit 3, Tab 2
Board Staff IR #13, #14
VECC IR #9, #10, #11, #13, #14

For the purposes of settlement, the Parties agree the CDM adjustment from gross to net is appropriate. The CDM adjustment for 2012 and 2013 CDM programs to the 2013 test year load forecast has been allocated to each rate class based on the 2011 Final OPA program results. The result is a reduction from 3,813,153 kWh under the gross method to 2,395,867 kWh under the net method. Settlement Table #5: CDM Adjusted Forecast, below provides the CDM impact on billed kW and kWh per customer class.

Settlement Table #5: CDM Adjusted Forecast

	Billed Load Forecast before CDM Adjustment (kWh)	Billed Load Forecast after CDM Adujustment (kWh)	CDM Adjustment (kWh)
Residential	50,600,390	50,241,010	359,380
GS<50 KW	23,841,425	21,972,649	1,868,777
GS>50 KW	120,167,711	120,000,000	167,711
Steet Lighting	1,338,353	1,338,353	0
USL	419,852	419,852	0
	196,367,731	193,971,864	2,395,867
	Billed Load Forecast before CDM Adjustment (kW)	**Billed Load Forecast after CDM Adujustment (kW)**	**CDM Adjustment (kW)**
GS>50 KW	293,059	292,641	419

For the purposes of settlement, the Parties agree the 2013 LRAMVA amount of 3,299,236 kWh and 576 kW has been calculated using the OPA's 2011-2014 CDM targets assigned to Midland, which reflects the actual 2011 CDM results and the persistence of 2011 into 2013. The LRAMVA amount differs from the CDM adjustment of 2,395,867 kWh's and 419 kW's, as the persistent savings from 2011 must be included in the calculation in order to capture the correct amount of targets assigned to Midland for 2013. Therefore, the 2013 LRAMVA includes the 2011 persistent savings of 903,369 kWh as provided by the OPA's 2011 Final Annual Report, 2012 persistent savings of 1,197,934 kWh and 2013 forecasted savings of 1,197,934 kWh. Settlement Table #6: LRAMVA Calculation, below provides details of the 2013 kWh and kW savings which will be used in the calculation of the LRAMVA account.

Settlement Table #6: LRAMVA Calculation

2011-2014 CDM Targets per Year				
2011	**2012**	**2013**	**2014**	**Total**
9.1%	8.3%	8.3%	7.8%	33.6%
	11.1%	11.1%	11.1%	33.2%
		11.1%	11.1%	22.1%
			11.1%	11.1%
9.1%	19.4%	30.5%	41.0%	100.0%

2011-2014 CDM kWh Targets per Year				
2011	**2012**	**2013**	**2014**	**Total**
983,008	903,369	903,369	842,652	3,632,398
	1,197,934	1,197,934	1,197,934	3,593,801
		1,197,934	1,197,934	2,395,867
		-	1,197,934	1,197,934
983,008	2,101,303	3,299,236	4,436,453	10,820,000

The Parties agree, for the purposes of settlement, the LRAMVA amount is to be allocated to the customer classes based on the percentages outlined in the OPA's Final Annual Report. Settlement Table #7: LRAMVA Allocation per Customer Class, below provides details of this allocation.

Settlement Table #7: LRAMVA Allocation per Customer Class

	LRAMVA kWh	Allocation per Class	Total LRAMVA kWh Allocated per Class	Total LRAMVA kW Allocated per Class
Residential		15%	494,885	0
GS<50 KW		78%	2,573,404	0
GS>50 KW		7%	230,947	576
Steet Lighting		0%	0	0
USL		0%	0	0
	3,299,236	100%	3,299,236	576

3.4 Is the proposed forecast of test year throughput revenue appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application, Exhibit 3, Tab 2 Settlement Agreement, Section 3.2, Appendix M

For the purposes of settlement, the Parties agree on the throughput revenue as set out in Appendix M: Throughput Revenue.

3.5 Is the test year forecast of other revenues appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application, Exhibit 3, Tab 3 VECC IR# 15 Settlement Agreement, Appendix E

For the purposes of settlement, the Parties agreed upon a forecast of $291,800 in Other Distribution Revenue, an increase of $28,196 from $263,604 as set out in the original application. Appendix E – 2013 Other Revenue provides additional detail.

The revised other revenue values reflect the following significant changes:

- The Parties agreed that it was appropriate to increase miscellaneous operating revenue by $5,600 to account for interest revenues in the 2013 test year forecast.
- The Parties agreed to remove the losses on disposal of assets of $22,596 which are not included in the 2013 forecast under CGAAP.

4. OPERATING COSTS

4.1 Is the overall OM&A forecast for the test year appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 4, Tab 2
Board Staff IR #15, #16, #17
SEC IR #13-17, #19
VECC #16-22
SEC Supplemental IR #6, #7, #8

For the purposes of settlement, the Parties agree the 2013 OM&A for the Test Year should be $2,320,000 (CGAAP), a decrease of $195,933 from the $2,515,933 original Application Filing and a decrease of $157,124 from the revised $2,477,124 submitted through the interrogatory process on December 3, 2012. The Parties relied on Midland's view that it can safely and reliably operate the distribution system based on the total OM&A budget proposed. Midland has provided, in Settlement Table #8: OM&A Expense Budget, below a revised OM&A budget based on this proposed total amount. The breakdown of the budget into categories is not intended by the Parties to be in any way a deviation from the normal rule that, once the budget is established, it is up to management to determine through the year how best to spend that budget given the actual circumstances and priorities of the company throughout the test year.

Settlement Table #8: OM&A Expense Budget

	Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
Operations	$378,987	($4,335)	$374,652	($3,677)	$370,975
Maintenance	$548,841	($29,273)	$519,568	($24,835)	$494,733
Billing & Collecting	$498,599	($1,897)	$496,703	($29,109)	$467,594
Community Relations	$4,450	($321)	$4,129	($272)	$3,856
Administrative and General	$1,085,056	($2,983)	$1,082,073	($99,231)	$982,842
Total	**$2,515,933**	**($38,809)**	**$2,477,124**	**($157,124)**	**$2,320,000**

4.2 Is the proposed level of depreciation/amortization expense for the test year appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 2 VECC IR #1 -5 SEC IR #9-12, #14, #18, #19 SEC Supplemental IR #4, #5, #6, #9

For the purposes of settlement, the Parties accept the useful lives proposed by Midland in Settlement Table #8: Depreciation Useful Lives, below and the depreciation expense reported in the continuity schedules in Appendix B. The Parties have agreed the proposed level of depreciation/amortization expense of $695,087 for the 2013 Test Year is appropriate.

As cited in Midland's Application, the LDC adopted the revised depreciation periods as indicated by the Kinectrics Study dated July 8, 2010 commissioned by the OEB. Midland is implementing this depreciation approach effective from January, 2013 and has applied it to the Test Year in its evidence. The Settlement Table #9: Depreciation Useful Lives, below summarizes the depreciation useful lives Midland has adopted.

It was agreed by all Parties that as Midland is operating under CGAAP accounting principles in the Test Year (not Modified IFRS), the LDC is not required to calculate and apply a PP&E adjustment.

Settlement Table #9: Depreciation Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life	Kinetric's Study
Overhead Systems				
Wood Poles	Poles, Towers, Fixtures	45	25	45
Concrete Poles	Poles, Towers, Fixtures	60	25	60
Steel Poles	Poles, Towers, Fixtures	60	25	60
Conductors	Poles, Towers, Fixtures	60	25	60
Transformers (Pole) & Voltage Regulators	Poles, Towers, Fixtures	40	25	40
Underground Systems				
PadMount Transformers	Transformers	40	25	40
Ducts	Underground Conduit	50	25	50
Primary Non-TR XLPE Cables Direct Buried	Underground Conductor	25	25	25
Transformer & Municipal Stations				
Power Transformers	Distribution Station Equipment	45	25	45
Station Metal Clad Switchgear	Distribution Station Equipment	40	25	40
Steel Structure	Distribution Station Equipment	25-75	25	50
DS Equipment - Other Components	Distribution Station Equipment	30	25	n/a
Civil Work, Site	Distribution Stations - parking, fencing & roof	25	25	25-30
Monitoring and Control				
Remote SCADA		20	15	20
Other Assets				
Office Equipment	Office Equipment	10	10	5-15
Vehicles - Trucks & Buckets	Vehicles	8	8	5-15
Vehicles - Trailers	Vehicles	8	5	5-20
Vehicles - Vans / Cars	Vehicles	8	5	5-10
Administrative Buildings	Buildings	50	20	50-75
Computer Hardware	Computer Hardware	5	5	3-5
Computer Software	Computer Software	5	5	2-5
Equipment - Power, Stores, Tools, Shop, Measure, Test	Tools, Shop and Garage Equipment	10	10	5-10
Residential Energy Meters	Meters	25	25	25-35
Industrial / Commercial Energy Meters	Meters	25	25	25-35
Wholesale Energy Meters	Meters	25	25	15-30
Smart Meters	Meters	15	15	5-15

4.3 Are the 2013 compensation costs and employee levels appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 2 Board Staff IR #17 SEC IR #16, #17 VECC IR #20, #21, #22 SEC Supplemental IR#8 Settlement Agreement, Section 4.1

For the purpose of settlement and subject to the overall reduction in 2013 Test Year OM&A discussed above in Section 4.1, the Parties accept Midland's forecast 2013 Test Year compensation costs and employee levels.

4.4 Is the test year forecast of property taxes appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 2

Midland has forecasted an amount of $30,385 in property taxes that will be payable in the 2013 Test Year.

For the purposes of settlement, the Parties accept Midland's 2013 Test Year forecast of property taxes from the original Application.

4.5 Is the test year forecast of PILs appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 4, Tab 3 Settlement Agreement, Appendix F

For the purpose of settlement, the parties accept Midland's 2013 Test Year PILs forecast as set out in Appendix F to this Settlement Agreement.

Please see Appendix F – 2013 PILs (Updated), for additional details.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

5.1 Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 5, Tab 1
Midland Supplemental #1
Settlement Agreement, Appendix G

For the purposes of settlement, the Parties have agreed that Midland's proposed capital structure of 56% long term debt, 4% short term debt, and 40% equity is appropriate.

This Settlement Agreement has been prepared using the Board's updated Cost of Capital Parameters for ROE (8.93%) and short term debt (2.08%) for cost of service applications for rates effective January 1, 2013, issued on November 15, 2012. For the purposes of settlement, Parties have agreed these rates will be applied for the May 1, 2013 implementation date. These updated parameters will also be incorporated into the Draft Rate Order to be prepared following the issuance of the Board's Decision on the Settlement Agreement. (Long-term debt is addressed separately in Section 5.2.)

Settlement Table #10: Deemed Capital Structure for 2013, below provides details of the above-noted parameters. Please also refer to Appendix G – 2013 Cost of Capital.

Settlement Table #10: Deemed Capital Structure for 2013

Description	Rate Base	% of Rate Base	Rate of Return	Return
Long Term Debt	$ 8,946,972	56%	3.61%	$ 322,801
Unfunded Short Term Debt	$ 639,069	4%	2.08%	$ 13,293
Total Debt	$ 9,586,041	60%		$ 336,093
Common Share Equity	$ 6,390,694	40%	8.93%	$ 570,689
Total Equity	$ 6,390,694	40%		$ 570,689
Total	$ 15,976,736	100%	5.68%	$ 906,782

5.2 Is the proposed long term debt rate appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 5, Tab 1 VECC IR #23 Midland Supplemental IR #2 Settlement Agreement, Appendix G

For the purposes of settlement, the Parties agreed to Midland's long term debt rate of 3.61%. The calculation of the long term debt rate is set out in Appendix G to this Agreement.

6. STRANDED METERS

6.1 Is the proposal related to Stranded Meters appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 9, Tab 3
Board Staff IR #19
VECC IR #30
Settlement Agreement, Section 1.4

For the purposes of settlement, the Parties accept the stranded meter net book value of $257,116 as presented in Settlement Table #11: Stranded Meter Customer Class Rate Rider, below. The Parties accept the proposal for recovery of the amount through a rate rider of $0.88 per metered Residential customer per month, and a rate rider of $2.22 metered General Service < 50 kW customer per month. Midland will recover costs over a three year period, commencing May 1, 2013.

Settlement Table #11: Stranded Meter Customer Class Rate Rider

Customer Class Rate Rider

Stranded Meter Costs	**Total Capital GL#1860**	**Less: Industrial**	**Stranded Meters**
Capital Cost	$ 1,117,459.65	$ (316,358.02)	$ 801,101.63
Accumulated Amortization	$ 739,082.26	$ (195,096.57)	$ 543,985.69
Net Book Value	$ 378,377.39	$ (121,261.46)	$ 257,115.93
	Residential	**Commercial**	**Total**
Number of Customers - 2013 Forecast	6231	755	6986
Allocation of Meter Costs - 2007 CA Model	77%	23%	100.0%
Stranded Assets - $	$ 196,699.34	$ 60,416.60	$ 257,115.93
Stranded Meter Rate Rider per Customer Class (SMRR)	**$ 0.88**	**$ 2.22**	
Annual Cost	**$ 10.52**	**$ 26.67**	

7. COST ALLOCATION

7.1 Is Midland's cost allocation appropriate

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 7
SEC IR# 21
VECC IR #24, #25
VECC Supplemental IR #2, #3
Settlement Agreement, Appendix K

The Parties have agreed for the purposes of settlement, the revenue-to-cost ratios for the 2013 Test Year, reflecting the agreed-upon 2013 Test Year Revenue Requirement, will be as set out in Settlement Table #12: 2013 Test Year Revenue to Cost Ratios, below.

Settlement Table #12: 2013 Test Year Revenue to Cost Ratios

Class	Revenue Requirement - 2013 Cost Allocation Model	2013 Base Revenue Allocated based on Proportion of Revenue allocated at Existing Rates	Miscellaneous Revenue Allocated from 2013 Cost Allocation Model	Total Revenue	Revenue Cost Ratio	Revenue Cost Ratios from 2013 Cost Allocation Model - Line 75 from O1 in CA	Proposed Revenue to Cost Ratio
Residential	$ 2,033,773	$ 2,141,913	$ 161,415	$ 2,303,328	113.25%	113.25%	113.25%
GS < 50 kW	$ 683,187	$ 540,767	$ 53,106	$ 593,873	86.93%	86.93%	86.93%
GS >50 to 4999 kW	$ 1,120,607	$ 838,302	$ 64,873	$ 903,176	80.60%	80.60%	81.83%
Street Lighting	$ 111,571	$ 126,576	$ 12,033	$ 138,609	124.23%	124.23%	120.00%
Unmetered and Scatte	$ 5,222	$ 15,001	$ 373	$ 15,375	294.40%	294.40%	120.00%
TOTAL	$ 3,954,361	$ 3,662,561	$ 291,800	$ 3,954,361			

Class	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	$ 2,303,328	$ 161,415	$ 2,141,913	85%	115%
GS < 50 kW	$ 593,873	$ 53,106	$ 540,767	80%	120%
GS >50 to 4999 kW	$ 917,008	$ 64,873	$ 852,135	80%	120%
Street Lighting	$ 133,885	$ 12,033	$ 121,852	70%	120%
Unmetered and Scatte	$ 6,267	$ 373	$ 5,893	80%	120%
TOTAL	$ 3,954,361	$ 291,800	$ 3,662,561		

Please see Appendix K – Cost Allocation Sheet O1for additional information.

7.2 Are the proposed revenue-to-cost ratios for each class appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, EP, VECC
Evidence:	Application: Exhibit 7 Settlement Agreement SEC IR# 21 VECC IR #24, #25 VECC Supplemental IR #2, #3 Settlement Agreement, Section 7.1

The Parties have agreed for the purposes of settlement the revenue-to-cost ratios for the 2013 Test Year, as set out under issue 7.1, above, are appropriate.

8. RATE DESIGN

8.1 Are the fixed-variable splits for each class appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 8, Schedule 1
SEC IR #22
VECC IR #28

For the purposes of settlement, the Parties accept the customer charges and the fixed-variable splits for each class presented in Settlement Table #13: Fixed Charge Analysis, below. In accordance with the initial Application, the Sentinel Light class will be eliminated.

Settlement Table #13: Fixed Charge Analysis

Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2012 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	46.82%	53.18%	100.00%	15.23	11.78	16.79
GS < 50 kW	64.14%	35.86%	100.00%	21.42	14.86	36.45
GS >50 to 4999 kW	90.45%	9.55%	100.00%	60.54	58.48	139.22
Street Lighting	25.40%	74.60%	100.00%	3.66	3.73	5.89
Unmetered and Scattered	75.82%	24.18%	100.00%	9.90	24.74	7.14
TOTAL						

The parties agree to the fixed and variable rates as set out in Settlement Table #14: 2013 Base Revenue Distribution Rates, below.

Settlement Table #14: 2013 Base Revenue Distribution Rates

Customer Class	Montthly Service Charge Per Connection	Monthly Service Charge Per Customer	kW	kWh
Residential		15.23		0.0200
GS < 50 kW		21.42		0.0158
GS >50 to 4999 kW		60.54	3.0849	
Street Lighting	3.66		8.4572	
Unmetered and Scattered	9.90			0.0106

8.2 Are the proposed retail transmission service rates (“RTSR”) appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 8, Schedule 1

For the purposes of settlement the Parties have agreed the following Retail Transmission Service Rates (“RTSRs”), based on the updated Uniform Transmission Rates issued by the Board on December 20, 2011 in EB-2011-0268, are appropriate, and are as set out in Settlement Table #15: RTSR Network and RTSR Connection Rates, below.

Settlement Table #15: RTSR Network and RTSR Connection Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0055	$ 0.0045
General Service Less Than 50 kW	kWh	$ 0.0050	$ 0.0041
General Service 50 to 4,999 kW	kW	$ 2.0550	$ 1.6356
Unmetered Scattered Load	kWh	$ 0.0050	$ 0.0041
Street Lighting	kW	$ 1.5499	$ 1.2644

8.3 Are the proposed LV rates appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 8, Schedule 1
VECC IR # 26

For the purposes of settlement, the Parties agree the total LV charges should be forecasted to total $357,677, as set out in the original Application adjusted for the load forecast increases as set out under Section 3 of this Settlement Agreement. For the purposes of settlement, the Parties have agreed that the adjusted LV Rates set out in Settlement Table #16: LV Rates 2013, below are appropriate.

Settlement Table #16: LV Rates – 2013

Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	101,244	50,241,010		kWh	0.0020	
GS < 50 kW	40,510	21,972,649		kWh	0.0018	
GS >50 to 4999 kW	213,089	120,000,000	292,641	kW		0.7282
Street Lighting	2,060	1,338,353	3,660	kW		0.5629
Unmetered and Scattered	774	419,852		kWh	0.0018	
TOTALS	357,677	193,971,864	296,300			

8.4 Are the proposed loss factors appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 8, Schedule 1, Schedule 6
Board Staff IR #18
VECC IR # 27

For the purposes of settlement, the Parties accept the Distribution Loss Factor of 1.0326 calculated using a 5 year average for the period 2007 to 2011 inclusive as shown in Settlement Table #17: Loss Factors, below.

When the Supply Facility Loss Factor of 1.0345 is applied to the Distribution Loss Factor the resulting Total Loss Factor for secondary metered customers is 1.0682 as shown in Settlement Table #17: Loss Factors, below:

Settlement Table #17: Loss Factors

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	240,226,974.50	230,112,011.00	217,320,554.30	220,973,975.10	214,540,510.60	224,634,805.10
A(2)	"Wholesale" kWh delivered to distributor (lower value)	232,327,828.40	222,551,885.20	210,025,260.20	213,537,360.70	207,396,158.55	217,167,698.61
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	232,327,828.40	222,551,885.20	210,025,260.20	213,537,360.70	207,396,158.55	217,167,698.61
D	"Retail" kWh delivered by distributor	224,566,924.22	215,492,783.00	203,110,374.00	207,341,771.00	201,044,063.00	210,311,183.04
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	224,566,924.22	215,492,783.00	203,110,374.00	207,341,771.00	201,044,063.00	210,311,183.04
G	Loss Factor in Distributor's system = **C / F**	1.0346	1.0328	1.0340	1.0299	1.0316	1.0326
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0340	1.0340	1.0349	1.0348	1.0349	1.0345
	Total Losses						
I	Total Loss Factor = **G x H**	1.0697	1.0679	1.0701	1.0658	1.0676	1.0682

9. DEFERRAL AND VARIANCE ACCOUNTS

9.1 Are the account balances, cost allocation methodology and disposition period appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 9 Board Staff IR #20-23 VECC IR #29, #30 Settlement Agreement, Section 6.1

For the purposes of settlement, the Parties have agreed the account balances, cost allocation methodology and disposition period for the deferral and variance accounts as presented in the evidence cited above, adjusted for the matters discussed below, are appropriate.

- The Parties have agreed for the purposes of settlement, that Midland has appropriately calculated the Stranded Meter Net Book Value as $257,116. The parties have further agreed to recovery of the Stranded Meter Net Book Value through Rate Riders in the amount of $0.88 per metered Residential customer, per month and $2.22 per General Service < 50 kW customer, per month over a three year period, as discussed in item 6.1, above.

- The Parties have agreed for the purposes of settlement, the valuation of the deferral and variance accounts for disposal include interest accrued until April 30, 2013.

- The Parties have agreed for the purposes of settlement, the balance in Account 1592, sub account HST/OVAT ITC, in Group 2 Accounts will be refunded to customers. This represents a disposal of $(17,560) as per the OEB's Account Procedures Handbook December 31, 2010 FAQ's. It was also agreed by all parties Midland would stop using Account 1592, sub account HST/OVAT ITC commencing December 31, 2012.

- The Parties have agreed, for the purposes of settlement, to dispose of the balance as at December 31, 2011 plus accrued interest to April 30, 2013, in Account #1508– Other Regulatory Assets – sub-account Deferred IFRS Transition Costs. In addition, the Parties have agreed Midland will continue to record in Account #1508 – Other Regulatory Asses – sub-account Deferred IFRS Transition Costs, all costs, revenues and interest pertaining to the transition to IFRS, which amounts will be disposed of in a future rate proceeding.

- The Parties have agreed to the disposition of all other Group 1 and Group 2 accounts as proposed in Midland's original Application except for those changes discussed above.

Settlement Table #18: Group 1 & Group 2 Deferral and Variance Accounts, below summarizes the Parties' agreement with respect to the disposal of the balances of the accounts:

Settlement Table #18: Group 1 & Group 2 Deferral and Variance Accounts

Account Description	Account Number	Principal Balance as at Dec 31, 2011	Interest Amounts as at Dec 31, 2011	Dec 31, 2011 Total	Projected Interest from Jan 1, 2012 to April 30, 2013 on Dec 31, 2011 Balances	Total Claim
Group 1 Accounts						
LV Variance Account	1550	$14,999	$101	$15,100	$294	$15,394
RSVA - Wholesale Market Service Charge	1580	($221,500)	($541)	($222,042)	($4,341)	($226,383)
RSVA - Retail Transmission Network Charge	1584	$26,043	$103	$26,146	$510	$26,656
RSVA - Retail Transmission Connection Charge	1586	($4,231)	($864)	($5,095)	($83)	($5,178)
RSVA - Power (excluding Global Adjustment)	1588	$407,316	$3,176	$410,492	$7,983	$418,475
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	($9,726)	$5,317	($4,409)	($191)	($4,600)
Total		**$212,900**	**$7,292**	**$220,192**	**$4,173**	**$224,365**

Account Description	Account Number	Principal Balance as at Dec 31, 2011	Interest Amounts as at Dec 31, 2011	Dec 31, 2011 Total	Projected Interest from Jan 1, 2012 to April 30, 2013 on Dec 31, 2011 Balances	Total Claim
Group 2 Accounts						
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$45,166	$301	$45,467	$885	$46,352
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$7,668	$171	$7,839	$150	$7,989
Retail Cost Variance Account - Retail	1518	($22,334)	($718)	($23,053)	($438)	($23,491)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	($34,109)	($343)	($34,452)	($669)	($17,560)
Total		**($3,610)**	**($590)**	**($4,199)**	**($71)**	**$13,290**

Account Description	Account Number	Principal Balance as at Dec 31, 2011	Interest Amounts as at Dec 31, 2011	Dec 31, 2011 Total	Projected Interest from Jan 1, 2012 to April 30, 2013 on Dec 31, 2011 Balances	Total Claim
Group 1 Accounts						
RSVA - Power - Global Adjustment Sub-Account	1588	$97,134	$2,609	$99,743	$1,904	$101,647

9.2 Are the proposed rate riders to dispose of the account balances appropriate?

Status: **Complete Settlement**

Supporting Parties: Midland, SEC, VECC

Evidence: Application: Exhibit 9

For the purposes of settlement, the Parties accept the proposed rate riders to dispose of those account balances that are the subject of disposition at this time on a final basis. The Parties have agreed to a disposition period of 12 months. The Parties' acceptance of a 12 month recovery on DVA balances, except for Stranded Meter recoveries, will allow Midland to maintain an appropriate cash flow position through recovery of outstanding amounts from its customers. As noted in section 6.1 above, the Parties have agreed, for the purposes of settlement that the Stranded Meter recovery period will be over three years, commencing May 1, 2013.

All Parties agree that a disposition period of 12 months is applied to the period of May 1, 2013 to April 30, 2014. Settlement Table #19: Deferral and Variance Account Disposition Balances, below reflects the balances of the accounts being disposed.

Settlement Table #19: Deferral and Variance Account Disposition Balances

Deferral and Variance Accouts	Account Description	Amount	Allocator	Residential	GS<50	GS>50	Street Lighting	Unmetered Scattered Load	Total
Group 1 Balances									
1550	LV Variance Account	$15,394	kWh	$3,636.61	$1,836.53	$9,779.05	$107.37	$34.58	$15,394
1580	RSVA - Wholesale Market Service Charge	($226,383)	kWh	($53,479.24)	($27,007.58)	($143,808.73)	($1,579.03)	($508.59)	($226,383)
1584	RSVA - Retail Transmission Network Charge	$26,656	kWh	$6,297.14	$3,180.12	$16,933.36	$185.93	$59.89	$26,656
1586	RSVA - Retail Transmission Connection Charge	($5,178)	kWh	($1,223.23)	($617.75)	($3,289.35)	($36.12)	($11.63)	($5,178)
1588	RSVA - Power (excluding Global Adjustment)	$418,475	kWh	$98,857.83	$49,924.24	$265,834.35	$2,918.87	$940.15	$418,475
1595	Recovery of Regulatory Asset Balances	($4,601)	Share Recovery Portion	($641.90)	($519.53)	($3,431.35)	($2.26)	($6.35)	($4,601)
Subtotal - Group 1 Balances		$224,363		$53,447.21	$26,796.03	$142,017.34	$1,594.77	$508.04	$224,363
Group 2 Balances									
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$46,352	# Customers	$40,531	$4,930	$785	$27	$80	$46,352
1508	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	$7,989	Distribution Rev.	$4,260	$1,137	$2,279	$275	$40	$7,989
1518	Retail Cost Variance Account - Retail	($23,491)	# of Customers	($20,540)	($2,498)	($398)	($13)	($40)	($23,491)
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	($17,560)	# Customers	($15,355)	($1,868)	($297)	($10)	($30)	($17,560)
Subtotal - Group 2 Balances		$13,290		$8,895	$1,700	$2,368	$278	$49	$13,290
Global Adjustment	RSVA - Power - Sub-account - Global Adjustment								
1588		$101,647	Non-RPP kWh	$5,584	$2,463	$92,508	$1,084	$7	$101,647
Total to be Recovered		$339,300		$67,927	$30,960	$236,894	$2,956	$564	$339,300

Settlement Table #20: Deferral and Variance Account Disposition Rate Riders, below reflects the rate riders for disposition over a period of 12 months.

Settlement Table #20: Deferral and Variance Account Disposition Rate Riders

Rate Class	Group 1 Accounts	Group 2 Accounts	Total	Billing Factor	Rate
Residential	$ 53,447	$ 8,895	$ 62,342	kWh	$0.00131
General Service <50 kW	$ 26,796	$ 1,700	$ 28,496	kWh	$0.00119
General Service >50 kW	$ 142,017	$ 2,368	$ 144,386	kW	$0.44403
Streetlights	$ 1,595	$ 278	$ 1,872	kW	$0.49104
Unmetered Scattered Load	$ 508	$ 49	$ 557	kWh	$0.00123
Total	$ 224,363	$ 13,290	$ 237,654		

Rate Class	RSVA - Power - Sub-account - Global Adjustment	Billing Factor	Rate
Residential	$ 5,584	kWh	$ 0.0008
General Service <50 kW	$ 2,463	kWh	$ 0.0008
General Service >50 kW	$ 92,508	kW	$ 0.3016
Streetlights	$ 1,084	kW	$ 0.2824
Unmetered Scattered Load	$ 7	kWh	$ 0.0008
Total	$ 101,647		

10. GREEN ENERGY ACT PLAN

10.1 Is Midland's Green Energy Act Plan, including the Smart Grid component of the plan appropriate?

Status:	**Complete Settlement**
Supporting Parties:	Midland, SEC, VECC
Evidence:	Application: Exhibit 2, Tab 6 Board Staff IR #9, #10

For the purposes of settlement, the Parties accept Midland's basic Green Energy Act Plan as set out in Midland's original Application.

Appendix A – Summary of Significant Changes

	Original Application (A)	Settlement Agreement (B)	Difference (B) - (A)
Rate Base			
Gross Fixed Assets (average)	$25,591,525	$26,039,622	$448,097
Accumulated Depreciation (average)	($12,457,078)	($12,973,203)	($516,124)
Allowance for Working Capital:			
Controllable Expenses	$2,546,318	$2,350,385	($195,933)
Cost of Power	$19,811,587	$20,036,663	$225,076
Working Capital Rate (%)	13.00%	13.00%	0.00%
Utility Income			
Operating Revenues:			
Distribution Revenue at Current Rates	$3,573,629	$3,596,458	$22,829
Distribution Revenue at Proposed Rates	$3,801,842	$3,662,561	($139,281)
Other Revenue			
Specific Service Charges	$108,600	$108,600	$ -
Late Payment Charges	$23,400	$23,400	$ -
Other Distribution Revenue	$131,604	$154,200	$22,596
Other Income and Deductions	$ -	$5,600	$5,600
Operating Expenses:			
OM+A Expenses	$2,515,933	$2,320,000	($195,933)
Depreciation/Amortization	$623,869	$695,087	$71,218
Property taxes	$30,385	$30,385	$ -
Taxes/PILs			
Taxable Income:			
Adjustments required to arrive at taxable income	($579,843)	($559,206)	$20,637
Utility Income Taxes and Rates:			
Income taxes (not grossed up)	$826	$1,780	$953
Income taxes (grossed up)	$978	$2,106	$1,128
Federal tax (%)	11.00%	11.00%	0.00%
Provincial tax (%)	4.50%	4.50%	0.00%
Capitalization/Cost of Capital			
Capital Structure:			
Long-term debt Capitalization Ratio (%)	56.0%	56.00%	0.00%
Short-term debt Capitalization Ratio (%)	4.0%	4.00%	0.00%
Common Equity Capitalization Ratio (%)	40.0%	40.00%	0.00%
Prefered Shares Capitalization Ratio (%)			
	100.0%	100.00%	0.00%
Cost of Capital			
Long-term debt Cost Rate (%)	3.44%	3.61%	0.17%
Short-term debt Cost Rate (%)	2.08%	2.08%	0.00%
Common Equity Cost Rate (%)	9.12%	8.93%	-0.19%
Prefered Shares Cost Rate (%)			
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	($13,323)	$ -	$13,323

Appendix A (Continued): Summary of Significant Changes

	Exhibit	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Property Taxes	Service Revenue Requirement	Revenue Offsets	Base Revenue Requirement	Gross Revenue Deficiency	Reference	Driver
Original Submission		$907,603	5.66%	$16,040,975	$22,357,905	$2,906,528	$623,869	$978	$2,515,933	$30,385	$4,065,446	$263,604	$3,801,842	$228,213	**Initial Application**	**Interrgatory Number**
61 VECC 24	7	$ 907,603	5.66%	$ 16,040,975	$ 22,357,905	$ 2,906,528	$ 623,869	$ 978	$ 2,515,933	$ 30,385	$ 4,065,446	$ 263,604	$ 3,801,842	$ 228,213	1st Round Interrogatories	VECC #24
Meter Costs - Cost Allocation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
59. VECC 23	5	$ 908,106	5.66%	$ 16,040,975	$ 22,357,905	$ 2,906,528	$ 623,869	$ 978	$ 2,515,933	$ 30,385	$4,065,941	$263,604	$ 3,802,337	$228,708	1st Round Interrogatories	VECC #23
change in Infrastructure Ontario rates		$503	$0	$0	$0	$0	$0	$0	$0	$0	$495	$0	$495	$495		
42. VECC 15	4	$ 911,626	5.66%	$ 16,103,158	$ 22,357,905	$ 2,906,528	$ 624,610	$ 62	$ 2,515,933	$ 30,385	$ 4,065,982	$ 291,800	$ 3,774,182	$ 200,553	1st Round Interrogatories	VECC #15
Int Rev /Loss-Disposal of Assets		$3,520	$0	$62,183	$0	$0	$741	-$916	$0	$0	$41	$28,196	-$28,155	-$28,155		
58. SEC 19	4	$ 911,626	5.66%	$ 16,103,158	$ 22,357,905	$ 2,906,528	$ 698,071	$ 62	$ 2,515,933	$ 30,385	$ 4,156,078	$ 291,800	$ 3,864,278	$ 290,649	1st Round Interrogatories	SEC #19
PP&E adjustment		$0	$0	$0	$0	$0	$73,461	$0	$0	$0	$90,096	$0	$90,096	$90,096		
69. VECC 29	9	$ 912,614	5.66%	$ 16,120,605	$ 22,492,112	$ 2,923,975	$ 698,071	$ 179	$ 2,515,933	$ 30,385	$ 4,157,183	$ 291,800	$ 3,865,383	$ 280,908	1st Round Interrogatories	VECC #29
SME/RPP changes/CDM		$988	$0	$17,447	$134,207	$17,447	$0	$117	$0	$0	$1,105	$0	$1,105	-$9,741		
43. VECC 16	4	$ 912,328	5.66%	$ 16,115,560	$ 22,453,303	$ 2,918,929	$ 698,071	$ 145	$ 2,477,124	$ 30,385	$ 4,118,054	$ 291,800	$ 3,826,254	$ 241,779	1st Round Interrogatories	VECC #16
2012 OM&A changes		-$286	$0	-$5,045	-$38,809	-$5,046	$0	-$34	-$38,809	$0	-$39,129	$0	-$39,129	-$39,129		
23. VECC 6	2	$ 904,956	5.66%	$ 15,985,349	$ 22,453,303	$ 2,918,929	$ 695,087	$ 4,391	$ 2,477,124	$ 30,385	$ 4,111,944	$ 291,800	$ 3,820,144	$ 235,669	1st Round Interrogatories	VECC #6
2012 Capital changes		-$7,372	$0	-$130,211	$0	$0	-$2,984	$4,246	$0	$0	-$6,110	$0	-$6,110	-$6,110		
Proposed at November 16, 2012		$904,956	$0	$15,985,349	$22,453,303	$2,918,929	$695,087	$4,391	$2,477,124	$30,385	$4,111,944	$291,800	$ 3,820,144	$235,669		
Midland TCQ 1		$ 907,271	5.68%	$ 15,985,349	$ 22,453,303	$ 2,918,929	$ 695,087	$ 2,163	$ 2,477,124	$ 30,385	$ 4,112,030	$ 291,800	$ 3,820,230	$ 235,755	2nd Round Interrogatories	Midland TCQ #1
Cost of Capital and LTD Changes		$2,315	0.02%	$0	$0	$0	$0	-$2,228	$0	$0	$86	$0	$86	$86		
Proposed at December 3, 2012		$ 907,271	5.68%	$ 15,985,349	$ 22,453,303	$ 2,918,929	$ 695,087	$ 2,163	$ 2,477,124		$ 4,112,030	$ 291,800	$ 3,820,230	$ 235,755		
Removal of Smart Meter Entity Charge in WC	2	$ 906,773	5.68%	$ 15,976,566	$ 22,385,742	$ 2,910,146	$ 695,087	$ 2,105	$ 2,477,124	$ 30,385	$ 4,111,474	$ 291,800	$ 3,819,674	$ 235,199	Settlement Conference	
		-$498		-$8,783	-$67,561	-$8,783	$0	-$58	$0	$30,385	-$556	$0	-$556	-$556		
Adjustments to Load - Change CDM from Gross to Net and change allocation of CDM Variable	2	$ 907,941	5.68%	$ 15,997,162	$ 22,544,172	$ 2,930,742	$ 695,087	$ 2,240	$ 2,477,124	$ 30,385	$ 4,112,778	$ 291,800	$ 3,820,978	$ 224,519	Settlement Conference	
		$1,168		$20,596	$158,430	$20,596	$0	$135	$0	$0	$1,304	$0	$1,304	-$10,680		
Reduction of OM&A Expenses - Envelope Change	4	$ 906,782	5.68%	$ 15,976,736	$ 22,387,048	$ 2,910,316	$ 695,087	$ 2,106	$ 2,320,000	$ 30,385	$ 3,954,361	$ 291,800	$ 3,662,561	$ 66,102	Settlement Conference	
		-$1,159		-$20,426	-$157,124	-$20,426	$0	-$134	-$157,124	$0	-$158,417	$0	-$158,417	-$158,417		
Revenue to Cost Ratio Adjustment	7	$ 906,782	5.68%	$ 15,976,736	$ 22,387,048	$ 2,910,316	$ 695,087	$ 2,106	$ 2,320,000	$ 30,385	$ 3,954,361	$ 291,800	$ 3,662,561	$ 66,102	Settlement Conference	
		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
Stranded Meter Rider change to 3 year collection from 1 year	9	$ 906,782	5.68%	$ 15,976,736	$ 22,387,048	$ 2,910,316	$ 695,087	$ 2,106	$ 2,320,000	$ 30,385	$ 3,954,361	$ 291,800	$ 3,662,561	$ 66,102	Settlement Conference	
		$0		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
Total Change from August 31, 2012 Submission		$ 821	0.02%	$ 64,239	$ (29,143)	$ (3,788)	$ (71,218)	$ (1,128)	$ 195,933	$ -	$ 111,085	$ (28,196)	$ 139,281	$ 162,111		
Proposed at December 21, 2013		$ 906,782	5.68%	$ 15,976,736	$ 22,387,048	$ 2,910,316	$ 695,087	$ 2,106	$ 2,320,000	$ 30,385	$ 3,954,361	$ 291,800	$ 3,662,561	$ 66,102		

Appendix B – 2013 Continuity Tables

			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)	0			0	-			0	0
CEC	1612	Land Rights (Formally known as Account 1906)	32,555			32,555	15,060.22			15,060	17,495
N/A	1805	Land	381,738	0	0	381,738	-	0	0	0	381,738
47	1806	Land Rights	0	0	0	0	-	0	0	0	0
13	1810	Leasehold Improvements	0			0	-			0	0
47	1815	Transformer Station Equipment - Normally Prima	0			0	-			0	0
47	1820	Distribution Station Equipment - Normally Prima	5,554,027	896,700	0	6,450,727	1,487,847	165,069	(0)	1,652,916	4,797,811
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	4,855,533	353,100	0	5,208,633	2,347,473	78,258	0	2,425,730	2,782,903
47	1835	Overhead Conductors and Devices	2,288,831	99,700	0	2,388,531	1,146,266	26,659	0	1,172,925	1,215,606
47	1840	Underground Conduit	1,948,941	0	0	1,948,941	1,346,413	16,021	0	1,362,434	586,507
47	1845	Underground Conductors and Devices	1,772,824	387,500	0	2,160,324	868,206	40,122	0	908,329	1,251,995
47	1850	Line Transformers	3,726,953	318,900	0	4,045,853	2,027,224	64,077	0	2,091,301	1,954,552
47	1855	Services	335,323	30,900	0	366,223	30,019	5,626	0	35,644	330,578
47	1860	Meters	1,115,459	10,000	801,102	324,357	739,042	33,834	543,986	228,891	95,466
47	1860	Meters (Smart Meters)	1,204,471			1,204,471	247,938	75,774		323,712	880,759
47	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
	1906	Land Rights	0			0	0			0	0
1	1908	Buildings and Fixtures	1,067,972	25,000	0	1,092,972	461,180	16,494	0	477,674	615,299
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment (10 years)	260,024	0	0	260,024	231,408	4,357	0	235,765	24,259
8	1915	Office Furniture and Equipment (5 years)	0			0	0			0	0
50	1920	Computer Equipment - Hardware	494,483	22,200	0	516,683	438,924	22,367	0	461,291	55,392
50	1920	Computer Equipment - Hardware (Smart Meters)	18,764			18,764	11,132	3,753		14,885	3,879
12	1925	Computer Software	373,256	65,000	0	438,256	324,735	24,911	0	349,647	88,610
12	1925	Computer Software (Smart Meters	68,016			68,016	35,435	13,603		49,038	18,978
10	1930	Transportation Equipment - Large Vehicles	1,011,195	0	0	1,011,195	278,968	126,399	0	405,368	605,828
10	1930	Transportation Equipment - Small Vehicles	171,823			171,823	131,797	9,487		141,283	30,540
8	1935	Stores Equipment	8,610			8,610	8,610			8,610	(0)
8	1940	Tools, Shop and Garage Equipment	289,725	10,000	0	299,725	219,506	12,961	0	232,467	67,257
8	1945	Measurement and Testing Equipment	2,634			2,634	2,634			2,634	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	134,110	0	0	134,110	132,331	300	0	132,631	1,479
8	1955	Communication Equipment (Smart Meters)								0	0
8	1960	Miscellaneous Equipment	19,220	0	0	19,220	18,955	177	0	19,132	88
47	1970	Load Management Controls - Customer Premise	0			0	0			0	0
47	1975	Load Management Controls - Utility Premises	0			0	0			0	0
12	1980	System Supervisory Equipment	562,328	120,000	0	682,328	314,444	19,047	0	333,492	348,836
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(2,166,197)	(588,100)	(64,211)	(2,690,085)	0	(64,211)	(64,211)	0	(2,690,085)
	2005	0	0			0	0			0	0
		Total before Work in Process	**25,532,617**	**1,750,900**	**736,891**	**26,546,627**	**12,865,547**	**695,087**	**479,775**	**13,080,859**	**13,465,768**
WIP		Work in Process	0			0	0			0	0
		Total after Work in Process	**25,532,617**	**1,750,900**	**736,891**	**26,546,627**	**12,865,547**	**695,087**	**479,775**	**13,080,859**	**13,465,768**

Appendix C – Cost of Power Calculation (Updated)

2013 Load Foreacst	kWh	kW	2011 %RPP		
Residential	50,241,010		85%		
General Service < 50 kW	21,972,649		87%		
General Service 50 to 4,999 kW	120,000,000	292,641	6%		
Street Lighting	1,338,353	3,660	0%		
Sentinel Lighting	0	-	0%		
Unmetered Scattered Load	419,852		98%		
TOTAL	**193,971,864**	**296,300**			

Electricity - Commodity RPP	2013	2013 Loss			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	42,591,931	1.0682	45,498,754	$0.07932	$3,608,961
General Service < 50 kW	19,100,953	1.0682	20,404,559	$0.07932	$1,618,490
General Service 50 to 4,999 kW	7,673,443	1.0682	8,197,142	$0.07932	$650,197
Street Lighting	0	1.0682	0	$0.07932	$0
Sentinel Lighting	0	1.0682	0	$0.07932	$0
Unmetered Scattered Load	412,051	1.0682	440,173	$0.07932	$34,915
TOTAL	**69,778,378**		**74,540,628**		**$5,912,563**

Electricity - Commodity Non-RPP	2013	2013 Loss			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	7,649,079	1.0682	8,171,115	$0.08001	$653,771
General Service < 50 kW	2,871,696	1.0682	3,067,684	$0.08001	$245,445
General Service 50 to 4,999 kW	112,326,557	1.0682	119,992,643	$0.08001	$9,600,611
Street Lighting	1,338,353	1.0682	1,429,693	$0.08001	$114,390
Sentinel Lighting	0	1.0682	0	$0.08001	$0
Unmetered Scattered Load	7,801	1.0682	8,333	$0.08001	$667
TOTAL	**124,193,486**		**132,669,468**		**$10,614,884**

Transmission - Network		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	53,669,869	$0.0055	$294,200
General Service < 50 kW		kW	23,472,243	$0.0050	$117,380
General Service 50 to 4,999 kW		kW	292,641	$2.0550	$601,362
Street Lighting		kWh	3,660	$1.5499	$5,672
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	448,506	$0.0050	$2,243
TOTAL					**$1,020,858**

Transmission - Connection		Volume			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	53,669,869	$0.0045	$242,933
General Service < 50 kW		kW	23,472,243	$0.0041	$97,203
General Service 50 to 4,999 kW		kW	292,641	$1.6356	$478,637
Street Lighting		kWh	3,660	$1.2644	$4,627
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	448,506	$0.0041	$1,857
TOTAL					**$825,257**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			53,669,869	$0.0052	$279,083
General Service < 50 kW			23,472,243	$0.0052	$122,056
General Service 50 to 4,999 kW			128,189,785	$0.0052	$666,587
Street Lighting			1,429,693	$0.0052	$7,434
Sentinel Lighting			0	$0.0052	$0
Unmetered Scattered Load			448,506	$0.0052	$2,332
TOTAL			**207,210,096**		**$1,077,492**

Appendix C – Cost of Power Calculation (Updated) – Cont'd

Rural Rate Assistance					
Class per Load Forecast			**2013**		
Residential			53,669,869	$0.0011	$59,037
General Service < 50 kW			23,472,243	$0.0011	$25,819
General Service 50 to 4,999 kW			128,189,785	$0.0011	$141,009
Street Lighting			1,429,693	$0.0011	$1,573
Sentinel Lighting			0	$0.0011	$0
Unmetered Scattered Load			448,506	$0.0011	$493
TOTAL			**207,210,096**		**$227,931**

	2013
4705-Pow er Purchased	$16,527,447
4708-Charges-WMS	$1,077,492
4714-Charges-NW	$1,020,858
4716-Charges-CN	$825,257
4730-Rural Rate Assistance	$227,931
4750-Low Voltage	$357,677
4708 - Smart Meter Entity	$0
TOTAL	**20,036,663**

Low Voltage					
Class per Load Forecast			**2013**		
Residential			53,669,869	$0.0021	$110,881
General Service < 50 kW			23,472,243	$0.0018	$42,027
General Service 50 to 4,999 kW			292,641	$0.6903	$202,013
Street Lighting			3,660	$0.5334	$1,952
Sentinel Lighting			0	$0.5322	$0
Unmetered Scattered Load			448,506	$0.0018	$803
TOTAL			**77,886,918**		**357,677**

Smart Meter Entity					
Class per Load Forecast		**# Customers**	**2013**		
Residential		6,231		$0.0000	$0
General Service < 50 kW		755		$0.0000	$0
General Service 50 to 4,999 kW				$0.0000	$0
Street Lighting				$0.0000	$0
Sentinel Lighting				$0.0000	$0
Unmetered Scattered Load				$0.0000	$0
TOTAL					**0**

Appendix D – 2013 Customer Load Forecast (Updated)

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normal	2013 Weather Normal
Actual kWh Purchases	239,348,510	241,297,274	246,226,714	237,573,474	240,154,177	230,112,011	217,320,554	220,975,056	214,550,355		
Predicted kWh Purchases	242,268,924	239,882,897	245,216,126	236,631,809	237,239,251	231,422,727	219,431,965	219,940,739	215,523,687	215,595,577	215,437,344
% Difference	1.2%	-0.6%	-0.4%	-0.4%	-1.2%	0.6%	1.0%	-0.5%	0.5%		
Billed kWh	224,245,320	227,207,627	233,239,880	225,666,133	221,449,219	211,182,817	205,136,897	205,745,412	200,633,462	200,614,137	193,971,864
By Class											
Residential											
Customers	5,531	5,533	5,661	5,727	5,828	5,896	6,031	6,053	6,084	6,157	6,231
kWh	46,627,475	46,604,134	48,370,215	46,733,608	47,949,044	48,324,089	48,075,570	48,092,980	47,612,325	49,007,567	50,241,010
GS<50											
Customers	689	718	715	709	730	719	720	740	741	748	755
kWh	27,036,581	26,788,353	26,768,114	26,084,744	26,869,560	25,808,718	25,357,510	25,080,220	23,384,283	22,727,212	21,972,649
GS>50											
Customers	114	114	114	106	107	110	111	112	113	113	112
kWh	148,856,264	152,507,008	156,958,341	151,705,109	145,013,829	135,337,092	129,998,410	130,739,365	127,781,460	127,073,248	120,000,000
kW		385,769	370,122	362,602	360,798	346,096	330,383	332,210	326,936	317,113	292,641
Streetlights											
Connections	1,384	1,469	1,487	1,523	1,525	1,525	1,525	1,915	1,911	1,990	2,072
kWh	1,690,021	1,254,703	1,100,219	1,117,167	1,072,530	1,178,359	1,169,602	1,370,178	1,402,281	1,369,944	1,338,353
kW		2,841	3,111	3,130	3,191	3,191	3,149	3,939	3,833	3,746	3,660
USL											
Connections	0	0	0	0	12	12	12	12	12	12	12
kWh	0	0	0	0	527,750	519,043	528,996	462,670	453,113	436,166	419,852
Total of Above											
Customer/Connections	7,734	7,872	8,013	8,090	8,224	8,284	8,419	8,832	8,861	9,019	9,181
kWh	224,245,320	227,207,627	233,239,880	225,666,133	221,449,219	211,182,817	205,136,897	205,745,412	200,633,462	200,614,137	193,971,864
kW from applicable classes	0	388,720	373,337	365,799	363,989	349,287	333,531	336,149	330,768	320,859	296,300

Appendix E – 2013 Other Revenue (Updated)

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
					2012	2012	2013
	Reporting Basis				CGAAP	MIFRS	MIFRS
4080	Standard Supply Admin Chg ($.25)	-$ 16,935	-$ 17,355	-$ 17,883	-$ 19,500	-$ 19,500	-$ 19,500
4210	Rent from Electric Property	-$ 90,166	-$ 82,895	-$ 80,638	-$ 77,300	-$ 77,300	-$ 78,200
4220	Other Electric Revenues	-$ 1,363	-$ 835	-$ 5,664	-$ 5,600	-$ 5,600	-$ 5,600
4225	Late Payment Charges	-$ 20,871	-$ 19,795	-$ 22,518	-$ 23,400	-$ 23,400	-$ 23,400
4310	Regulatory Credits						$ -
4235	Specific Service Charges	-$ 105,670	-$ 108,002	-$ 121,897	-$ 122,100	-$ 122,100	-$ 108,600
4325	Rev From Merchandising, Jobbing	-$ 34,900	-$ 85,867	-$ 78,046	-$ 92,500	-$ 92,500	-$ 94,300
4330	Costs and Exp Merchandising, Jobbing	$ 18,636	$ 63,870	$ 54,180	$ 63,000	$ 63,000	$ 64,500
4357	Gain from Retirement of Utility and Other Pr	-$ 13,025	$ -	$ -	-$ 26,855	-$ 26,855	$ -
4362	Loss from Retirement of Utility and Other Pro	$ -	$ 2,543	$ 2,433	$ -	$ -	$ -
4375	Rev from Non-Utility Operations	-$ 303,650	-$ 225,318	-$ 60,591	-$ 57,600	-$ 57,600	-$ 58,800
4380	Expenses from Non-Utility Op'n	$ 229,702	$ 177,889	$ 42,125	$ 36,800	$ 36,800	$ 37,700
4405	Interest & Dividend Income	-$ 37,483	-$ 33,635	-$ 51,417	-$ 5,600	-$ 5,600	-$ 5,600
Specific Service Charges		-$ 105,670	-$ 108,002	-$ 121,897	-$ 122,100	-$ 122,100	-$ 108,600
Late Payment Charges		-$ 20,871	-$ 19,795	-$ 22,518	-$ 23,400	-$ 23,400	-$ 23,400
Other Operating Revenues		-$ 108,464	-$ 101,085	-$ 104,185	-$ 102,400	-$ 102,400	-$ 103,300
Other Income or Deductions		-$ 140,720	-$ 100,517	-$ 91,317	-$ 82,755	-$ 82,755	-$ 56,500
Total		-$ 375,725	-$ 329,399	-$ 339,917	-$ 330,655	-$ 330,655	-$ 291,800

Appendix F – 2013 PILS (Updated)

2013 PILs Schedule

Description	Source or Input	Tax Payable
Accounting Income	Rev Def	572,795
Tax Adj to Accounting Income	Rev Def	(559,206)
Taxable Income		**13,590**
Combined Income Tax Rate	PILs Rates	15.500%
Total Income Taxes		**2,106**
Investment Tax Credits		
Apprentice Tax Credits		
Other Tax Credits (SBD)		-
Total PILs		**2,106**

2013 Total Taxes

Description	Tax Payable
Total PILs	2,106
PILs including Capital Taxes	2,106

Appendix G – 2013 Cost of Capital (Updated)

Year 2009

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Short Term Loan Advance	Infrastructure Ontario	Third-Party	Variable Rate	15-Dec-09	1	$ 1,422,519	1.74%	$ 1,031.33
Total							$ 1,422,519	0.000725	$ 1,031.33

Year 2010

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Debenture # 3	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 270,000	2.91%	$ 6,335.83
2	Debenture # 1	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 1,066,393	3.91%	$ 32,400.81
3	Debenture # 2	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 1,173,250	3.91%	$ 35,647.50
4	Short Term Loan Advance	Infrastructure Ontario	Third-Party	Fixed Rate	16-Feb-10	1	$ 900,000	1.74%	$ 13,726.13
Total							$ 3,409,643	2.58%	$ 88,110.26

Year 2011

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Debenture # 3	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 210,000	2.91%	$ 7,022.28
2	Debenture # 1	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 954,141	3.91%	$ 39,717.90
3	Debenture # 2	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 1,049,750	3.91%	$ 43,697.79
4	Debenture # 5	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-11	10	$ 1,140,000	4.00%	$ 39,355.61
5	Debenture # 4	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jun-11	15	$ 966,667	4.12%	$ 22,320.43
Total							$ 4,320,558	3.52%	$ 152,114.00

Year 2012

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Debenture # 3	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 150,000	2.91%	$ 5,223.65
2	Debenture # 1	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 841,889	3.91%	$ 35,016.20
3	Debenture # 2	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 926,250	3.91%	$ 38,524.97
4	Debenture # 5	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-11	10	$ 1,020,000	4.00%	$ 42,976.44
5	Debenture # 4	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jun-11	15	$ 900,000	4.12%	$ 39,334.72
6	Debenture # 6	Infrastructure Ontario	Third-Party	Fixed Rate	1-Sep-12	10	$ 542,000	3.50%	$ 1,580.83
7	Debenture # 7	Infrastructure Ontario	Third-Party	Fixed Rate	1-Sep-12	5	$ 430,000	2.79%	$ 999.75
Total							$ 4,810,139	3.40%	$ 163,656.55

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)
1	Debenture # 3	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	5	$ 90,000	2.91%	$ 3,492.00
2	Debenture # 1	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 729,637	3.91%	$ 30,723.35
3	Debenture # 2	Infrastructure Ontario	Third-Party	Fixed Rate	1-Apr-10	10	$ 802,750	3.91%	$ 33,801.96
4	Debenture # 5	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-11	10	$ 900,000	4.00%	$ 38,101.92
5	Debenture # 4	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jun-11	15	$ 833,333	4.12%	$ 36,179.50
6	Debenture # 6	Infrastructure Ontario	Third-Party	Fixed Rate	1-Sep-12	20	$ 487,800	3.50%	$ 18,337.67
7	Debenture # 7	Infrastructure Ontario	Third-Party	Fixed Rate	1-Sep-12	10	$ 344,000	2.79%	$ 11,197.20
8	Debenture #8	Infrastructure Ontario	Third-Party	Fixed Rate	1-Sep-13	20	$ 850,000	3.50%	$ 9,916.67
Total							$ 5,037,521	3.61%	$ 181,750.24

Appendix G – 2013 Cost of Capital (Updated) – Cont'd

Particulars	Capitalization Ratio		2013	Cost Rate	Return
			Application		
	(%)		($)	(%)	($)
Debt					
Long-term Debt	56.00%		$8,946,972	3.61%	$322,801
Short-term Debt	4.00%	(1)	$639,069	2.08%	$13,293
Total Debt	60.0%		$9,586,041	3.51%	$336,093
Equity					
Common Equity	40.00%		$6,390,694	8.93%	$570,689
Preferred Shares	0.00%		$ -		$ -
Total Equity	40.0%		$6,390,694	8.93%	$570,689
Total	100.0%		$15,976,736	5.68%	$906,782

Appendix H – 2013 Revenue Deficiency (Updated)

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**66,102**
Distribution Revenue	3,659,942	3,596,458	3,596,458
Other Operating Revenue (Net)	311,155	291,800	291,800
Total Revenue	**3,971,098**	**3,888,258**	**3,954,361**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,413,412	1,454,292	1,454,292
Operation & Maintenance	806,988	865,708	865,708
Depreciation & Amortization	641,912	695,087	695,087
Amortization on PP&E Adjustment		0	0
Return on PP&E Adjustment		0	0
Property Taxes	29,500	30,385	30,385
Deemed Interest	397,478	336,093	336,093
Total Costs and Expenses	**3,289,290**	**3,381,565**	**3,381,565**
Utility Income Before Income Taxes	**681,808**	**506,693**	**572,795**
Income Taxes:			
Corporate Income Taxes	9,202	-8,139	2,106
Total Income Taxes	**9,202**	**-8,139**	**2,106**
Utility Net Income	**672,606**	**514,833**	**570,689**
Income Tax Expense Calculation:			
Accounting Income	681,808	506,693	572,795
Tax Adjustments to Accounting Income	-622,442	-559,206	-559,206
Taxable Income	**59,366**	**-52,513**	**13,590**
Income Tax Expense	9,202	-8,139	2,106
Tax Rate Refecting Tax Credits	15.5000%	15.5000%	15.50%
Actual Return on Rate Base:			
Rate Base	14,990,123	15,976,736	15,976,736
Interest Expense	397,478	336,093	336,093
Net Income	672,606	514,833	570,689
Total Actual Return on Rate Base	**1,070,084**	**850,926**	**906,782**
Actual Return on Rate Base	7.14%	5.33%	5.68%
Required Return on Rate Base:			
Rate Base	14,990,123	15,976,736	15,976,736
Return Rates:			
Return on Debt (Weighted)	4.42%	3.51%	3.51%
Return on Equity	8.01%	8.93%	8.93%
Deemed Interest Expense	397,478	336,093	336,093
Return On Equity	480,284	570,689	570,689
Total Return	**877,762**	**906,782**	**906,782**
Expected Return on Rate Base	5.86%	5.68%	5.68%
Revenue Deficiency After Tax	**-192,323**	**55,856**	**0**
Revenue Deficiency Before Tax	**-227,601**	**66,102**	**0**

Tax Exhibit			2013
Deemed Utility Income			570,689
Tax Adjustments to Accounting Income			(559,206)
xable Income prior to adjusting revenue to PILs			**11,483**
Tax Rate			15.50%
Total PILs before gross up			**1,780**
Grossed up PILs			**2,106**

Appendix I – Proposed 2013 Schedule of Rates and Charges (Updated)

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously Approved schedules of Rates, Charges and Loss Factors

EB-2012-0147

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account where energy is supplied to customers residing in residential dwelling units. Energy is generally supplied as a single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts and having only one Delivery Point per dwelling. For the purposes of calculating customer connection fees, the Basic Connection for Residential customers is defined as 100 amp 120/240 volt overhead service. A residential building is supplied at one service voltage per land parcel. Street Townhouses and Condominiums requiring centralization bulk metering are covered under General Service Classification. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.23
Distribution Volumetric Rate	$/kWh	0.0200
Low Voltage Service Rate	$/kWh	0.0020
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	0.0013
Rate Rider for Stranded Meter Disposition (2013) – effective until April 30, 2016	$	0.88
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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EB-2012-0147

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Townhouses and Condominiums that require centralized bulk metering. General Service buildings are defined as buildings that are used for purposes other than single-family dwellings. A General Service building is supplied at one voltage per land parcel. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	21.42
Distribution Volumetric Rate	$/kWh	0.0158
Low Voltage Service Rate	$/kWh	0.0018
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	0.0012
Rate Rider for Stranded Meter Disposition (2013) – effective until April 30, 2016	$	2.22
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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Approved schedules of Rates, Charges and Loss Factors

EB-2012-0147

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to General Service customers requiring a connection with a connected load equal to or greater than 50 kW and less than 5,000 kW. A General Service building is supplied at one service voltage per land parcel. Depending on the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

- 2,400/4,160 volts 3 Phase 4Wire
- 4,800/8,320 volts 3 Phase 4 Wire
- 7,200/12,400 volts 3 Phase 4 Wire
- 8,000/13,800 volts 3 Phase 4 Wire
- 16,000/27,600 volts 3 Phase 4 Wire
- 44,000 Volts 3 Phase 3 Wire

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	60.54
Distribution Volumetric Rate	$/kW	3.0849
Low Voltage Service Rate	$/kW	0.7282
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.3016
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	0.4440
Retail Transmission Rate – Network Service Rate	$/kW	2.0550
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6356

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously Approved schedules of Rates, Charges and Loss Factors

EB-2012-0147

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	9.90
Distribution Volumetric Rate	$/kWh	0.0106
Low Voltage Service Rate	$/kWh	0.0018
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0008
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	0.0012
Retail Transmission Rate – Network Service Rate	$/kWh	0.0050
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

**This schedule supersedes and replaces all previously
Approved schedules of Rates, Charges and Loss Factors**

EB-2012-0147

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	3.66
Distribution Volumetric Rate	$/kW	8.4572
Low Voltage Service Rate	$/kW	0.5629
Rate Rider for Global Adjustment Sub-Account Disposition (2013) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.2824
Rate Rider for Deferral/Variance Account Disposition (2013) – effective until April 30, 2014	$/kWh	0.4910
Retail Transmission Rate – Network Service Rate	$/kW	1.5499
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2644

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously Approved schedules of Rates, Charges and Loss Factors

EB-2012-0147

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.40

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

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Approved schedules of Rates, Charges and Loss Factors

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Notification Charge	$	15.00
Account history	$	15.00
Returned Cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Non-Payment of Account		
Late Payment – per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Specific Charge for Access to Power Poles $/pole/year	$	22.35
Interval Meter Load Management Tool charge	$	25.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00

Midland Power Utility Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously Approved schedules of Rates, Charges and Loss Factors

EB-2012-0147

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0682
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0576
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Appendix J - Updated Customer Impact - Residential (Updated)

Consumption 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 11.7800	1	$ 11.78	$ 15.2300	1	$ 15.23	$ 3.45	29.29%
Smart Meter Rate Adder	Monthly	$ 3.1800	1	$ 3.18		1	$ -	-$ 3.18	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0196	800	$ 15.68	$ 0.0200	800	$ 16.00	$ 0.32	2.04%
Smart Meter Disposition Rider	Monthly	-$ 0.9600	1	-$ 0.96		1	$ -	$ 0.96	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	800	$ 0.04		800	$ -	-$ 0.04	-100.00%
Sub-Total A				$ 29.72			$ 31.23	**$ 1.51**	**5.08%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0070	800	-$ 5.60	$ 0.0013	800	$ 1.05	$ 6.65	-118.75%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.8769	1	$ 0.88	$ 0.88	
Low Voltage Service Charge	per kWh	$ 0.0015	800	$ 1.20	$ 0.0020	800	$ 1.60	$ 0.40	33.33%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.32**			**$ 34.76**	**$ 9.44**	**37.27%**
RTSR - Network	per kWh	$ 0.0057	852	$ 4.86	$ 0.0055	855	$ 4.68	-$ 0.17	-3.55%
RTSR - Line and Transformation Connection	per kWh	$ 0.0047	852	$ 4.00	$ 0.0045	855	$ 3.87	-$ 0.14	-3.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.18**			**$ 43.31**	**$ 9.13**	**26.70%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	852	$ 4.43	$ 0.0052	855	$ 4.44	$ 0.01	0.29%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	852	$ 0.94	$ 0.0011	855	$ 0.94	$ 0.00	0.29%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Smart Meter Entity Charge	Monthly		1		$ -	1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0740	600	$ 44.40	-$ 0.60	-1.33%
Energy - RPP - Tier 2		$ 0.0880	252	$ 22.18	$ 0.0870	255	$ 22.15	-$ 0.04	-0.16%
TOU - Off Peak		$ 0.0650	545	$ 35.45	$ 0.0630	547	$ 34.46	-$ 0.99	-2.79%
TOU - Mid Peak		$ 0.1000	153	$ 15.34	$ 0.0990	154	$ 15.23	-$ 0.11	-0.71%
TOU - On Peak		$ 0.1170	153	$ 17.94	$ 0.1180	154	$ 18.15	$ 0.21	1.15%
Total Bill on RPP (before Taxes)				**$ 112.58**			**$ 121.09**	**$ 8.51**	**7.56%**
HST		13%		$ 14.64	13%		$ 15.74	$ 1.11	7.56%
Total Bill (including HST)				$ 127.22			$ 136.83	$ 9.61	7.56%
Ontario Clean Energy Benefit [1]				-$ 12.72			-$ 13.68	-$ 0.96	7.55%
Total Bill on RPP (including OCEB)				**$ 114.50**			**$ 123.15**	**$ 8.65**	**7.56%**
Total Bill on TOU (before Taxes)				**$ 114.13**			**$ 122.38**	**$ 8.25**	**7.23%**
HST		13%		$ 14.84	13%		$ 15.91	$ 1.07	7.23%
Total Bill (including HST)				$ 128.97			$ 138.29	$ 9.32	7.23%
Ontario Clean Energy Benefit [1]				-$ 12.90			-$ 13.83	-$ 0.93	7.21%
Total Bill on TOU (including OCEB)				**$ 116.07**			**$ 124.46**	**$ 8.39**	**7.23%**

	Current Board-Approved	Proposed
Loss Factor (%)	6.5100%	6.8200%

Appendix J - Updated Customer Impact - General Service < 50 kW (Updated)

Consumption 2000 kWh

○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

	Charge	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	% Change
Monthly Service Charge	Monthly	$ 14.8600	1	$ 14.86	$ 21.4200	1	$ 21.42	$ 6.56	44.15%
Smart Meter Rate Adder	Monthly	$ 6.1700	1	$ 6.17		1	$ -	-$ 6.17	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0155	2000	$ 31.00	$ 0.0158	2000	$ 31.60	$ 0.60	1.94%
Smart Meter Disposition Rider	Monthly	$ 5.3400	1	$ 5.34		1	$ -	-$ 5.34	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40		2000	$ -	-$ 0.40	-100.00%
Sub-Total A				$ 57.77			$ 53.02	**-$ 4.75**	**-8.22%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0048	2000	-$ 9.60	$ 0.0012	2000	$ 2.38	$ 11.98	-124.75%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 2.2228	1	$ 2.22	$ 2.22	
Low Voltage Service Charge	per kWh	$ 0.0013	2000	$ 2.60	$ 0.0018	2000	$ 3.60	$ 1.00	38.46%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 50.77**			**$ 61.22**	**$ 10.45**	**20.58%**
RTSR - Network	per kWh	$ 0.0052	2130	$ 11.08	$ 0.0050	2136	$ 10.68	-$ 0.39	-3.55%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2130	$ 9.16	$ 0.0041	2136	$ 8.85	-$ 0.31	-3.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 71.01**			**$ 80.75**	**$ 9.74**	**13.72%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	2130	$ 11.08	$ 0.0052	2136	$ 11.11	$ 0.03	0.29%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	2130	$ 2.34	$ 0.0011	2136	$ 2.35	$ 0.01	0.29%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Smart Meter Entity Charge	Monthly				$ -	1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0740	600	$ 44.40	-$ 0.60	-1.33%
Energy - RPP - Tier 2		$ 0.0880	1530	$ 134.66	$ 0.0870	1536	$ 133.67	-$ 0.99	-0.74%
TOU - Off Peak		$ 0.0650	1363	$ 88.62	$ 0.0630	1367	$ 86.14	-$ 2.48	-2.79%
TOU - Mid Peak		$ 0.1000	383	$ 38.34	$ 0.0990	385	$ 38.07	-$ 0.27	-0.71%
TOU - On Peak		$ 0.1170	383	$ 44.86	$ 0.1180	385	$ 45.38	$ 0.52	1.15%
Total Bill on RPP (before Taxes)				**$ 278.33**			**$ 286.53**	**$ 8.19**	**2.94%**
HST		13%		$ 36.18	13%		$ 37.25	$ 1.06	2.94%
Total Bill (including HST)				$ 314.52			$ 323.77	$ 9.26	2.94%
Ontario Clean Energy				-$ 31.45			-$ 32.38	-$ 0.93	2.96%
Total Bill on RPP (including				**$ 283.07**			**$ 291.39**	**$ 8.33**	**2.94%**
Total Bill on TOU (before Taxes)				**$ 270.50**			**$ 278.05**	**$ 7.55**	**2.79%**
HST		13%		$ 35.16	13%		$ 36.15	$ 0.98	2.79%
Total Bill (including HST)				$ 305.66			$ 314.19	$ 8.53	2.79%
Ontario Clean Energy				-$ 30.57			-$ 31.42	-$ 0.85	2.78%
Total Bill on TOU (including				**$ 275.09**			**$ 282.77**	**$ 7.68**	**2.79%**

Loss Factor (%) 6.5100% 6.8200%

Appendix J - Updated Customer Impact - General Service > 50 kW (Updated)

○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

Consumption 1095000 kWh Consumption 2500 KW

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 58.4800	1	$ 58.48	$ 60.5400	1	$ 60.54	$ 2.06	3.52%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.9954	2500	$ 7,488.50	$ 3.0849	2500	$ 7,712.25	$ 223.75	2.99%
			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0093	2500	$ 23.25		2500	$ -	-$ 23.25	-100.00%
Sub-Total A				$ 7,570.23			$ 7,772.79	**$ 202.56**	**2.68%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3786	2500	-$ 3,446.50	$ 0.4440	2500	$ 1,110.08	$ 4,556.58	-132.21%
Low Voltage Service Charge	per kW	$ 0.5012	2500	$ 1,253.00	$ 0.7282	2500	$ 1,820.50	$ 567.50	45.29%
	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,376.73**			**$ 10,703.37**	**$ 5,326.64**	**99.07%**
RTSR - Network	per kW	$ 2.1368	2500	$ 5,342.00	$ 2.0550	2500	$ 5,137.38	-$ 204.62	-3.83%
RTSR - Line and Transformation Connection	per kW	$ 1.6983	2500	$ 4,245.75	$ 1.6356	2500	$ 4,088.95	-$ 156.80	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,964.48**			**$ 19,929.70**	**$ 4,965.22**	**33.18%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1166285	$ 6,064.68	$ 0.0052	1169679	$ 6,082.33	$ 17.65	0.29%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1166285	$ 1,282.91	$ 0.0011	1169679	$ 1,286.65	$ 3.73	0.29%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1095000	$ 7,665.00	$ 0.0070	1095000	$ 7,665.00	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0870		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	1166285	$ 94,107.50	$ 0.0793	1169679	$ 92,778.94	-$ 1,328.56	-1.41%
		$ 0.1000		$ -			$ -	$ -	
		$ 0.1170		$ -			$ -	$ -	
Total Bill on Commodity COP				**$ 124,084.82**			**$ 127,742.87**	**$ 3,658.05**	**2.95%**
HST		13%		$ 16,131.03	13%		$ 16,606.57	$ 475.55	2.95%
Total Bill (including HST)				$ 140,215.85			$ 144,349.44	$ 4,133.60	2.95%
Ontario Clean Energy Benefit [1]				-$ 14,021.58			-$ 14,434.94	-$ 413.36	2.95%
Total Bill on TOU (including OCEB)				**$ 126,194.27**			**$ 129,914.50**	**$ 3,720.24**	**2.95%**

Loss Factor (%) 6.5100% 6.8200%

Appendix J - Updated Customer Impact – Unmetered Scattered Load (Updated)

○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

Consumption 275 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 24.7400	1	$ 24.74	$ 9.8979	1	$ 9.90	-$ 14.84	-59.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0266	275	$ 7.32	$ 0.0106	275	$ 2.92	-$ 4.40	-60.15%
Sub-Total A				$ 32.06			$ 12.81	**-$ 19.24**	**-60.03%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0066	275	-$ 1.82	$ 0.0012	275	$ 0.34	$ 2.15	-118.68%
Low Voltage Service Charge	per kWh	$ 0.0013	275	$ 0.36	$ 0.0018	275	$ 0.50	$ 0.14	38.46%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.60**			**$ 13.65**	**-$ 16.95**	**-55.40%**
RTSR - Network	per kWh	$ 0.0052	293	$ 1.52	$ 0.0050	294	$ 1.47	-$ 0.05	-3.55%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	293	$ 1.26	$ 0.0041	294	$ 1.22	-$ 0.04	-3.41%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.38**			**$ 16.33**	**-$ 17.05**	**-51.07%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	293	$ 1.52	$ 0.0052	294	$ 1.53	$ 0.00	0.29%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	293	$ 0.32	$ 0.0011	294	$ 0.32	$ 0.00	0.29%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	275	$ 1.93	$ 0.0070	275	$ 1.93	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	293	$ 21.97	$ 0.0740	294	$ 21.74	-$ 0.23	-1.05%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	187	$ 12.18	$ 0.0630	188	$ 11.84	-$ 0.34	-2.79%
TOU - Mid Peak		$ 0.1000	53	$ 5.27	$ 0.0990	53	$ 5.23	-$ 0.04	-0.71%
TOU - On Peak		$ 0.1170	53	$ 6.17	$ 0.1180	53	$ 6.24	$ 0.07	1.15%
Total Bill on RPP (before Taxes)				**$ 59.37**			**$ 42.10**	**-$ 17.27**	**-29.09%**
HST		13%		$ 7.72	13%		$ 5.47	-$ 2.25	-29.09%
Total Bill (including HST)				$ 67.09			$ 47.57	-$ 19.52	-29.09%
Ontario Clean Energy Benefit [1]				-$ 6.71			-$ 4.76	$ 1.95	-29.06%
Total Bill on RPP (including OCEB)				**$ 60.38**			**$ 42.81**	**-$ 17.57**	**-29.10%**
Total Bill on TOU (before Taxes)				**$ 61.03**			**$ 43.68**	**-$ 17.35**	**-28.43%**
HST		13%		$ 7.93	13%		$ 5.68	-$ 2.26	-28.43%
Total Bill (including HST)				$ 68.96			$ 49.35	-$ 19.60	-28.43%
Ontario Clean Energy Benefit [1]				-$ 6.90			-$ 4.94	$ 1.96	-28.41%
Total Bill on TOU (including OCEB)				**$ 62.06**			**$ 44.41**	**-$ 17.64**	**-28.43%**

	Current	Proposed
Loss Factor (%)	6.5100%	6.8200%

Appendix J - Updated Customer Impact – Streetlighting (Updated)

○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

Consumption 108,831 kWh Consumption 295 KW

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 3.7300	1500	$ 5,595.00	$ 3.6568	1500	$ 5,485.20	-$ 109.80	-1.96%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 8.6265	295	$ 2,544.82	$ 8.4572	295	$ 2,494.87	-$ 49.94	-1.96%
Sub-Total A				$ 8,139.82			$ 7,980.07	**-$ 159.74**	**-1.96%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0013	295	$ 0.38	$ 0.4910	295	$ 144.86	$ 144.47	37672.68%
Low Voltage Service Charge	per kW	$ 0.3873	295	$ 114.25	$ 0.5629	295	$ 166.06	$ 51.80	45.34%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8,254.45**			**$ 8,290.99**	**$ 36.53**	**0.44%**
RTSR - Network	per kW	$ 1.6116	295	$ 475.42	$ 1.5499	295	$ 457.21	-$ 18.21	-3.83%
RTSR - Line and Transformation Connection	per kW	$ 1.3129	295	$ 387.31	$ 1.2644	295	$ 373.00	-$ 14.30	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 9,117.18**			**$ 9,121.20**	**$ 4.02**	**0.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	115916	$ 602.76	$ 0.0052	116253	$ 604.52	$ 1.75	0.29%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	115916	$ 127.51	$ 0.0011	116253	$ 127.88	$ 0.37	0.29%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	108831	$ 761.82	$ 0.0070	108831	$ 761.82	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	108831	$ 8,781.57	$ 0.0793	108831	$ 8,632.47	-$ 149.10	-1.70%
		$ 0.1000		$ -	$ 0.1000		$ -	$ -	
		$ 0.1170		$ -	$ 0.1170		$ -	$ -	
Total Bill on Commodity COP				**$ 19,391.09**			**$ 19,248.14**	**-$ 142.95**	**-0.74%**
HST		13%		$ 2,520.84	13%		$ 2,502.26	-$ 18.58	-0.74%
Total Bill (including HST)				$ 21,911.93			$ 21,750.40	-$ 161.54	-0.74%
Ontario Clean Energy Benefit [1]				-$ 2,191.19			-$ 2,175.04	$ 16.15	-0.74%
Total Bill on TOU (including OCEB)				**$ 19,720.74**			**$ 19,575.36**	**-$ 145.39**	**-0.74%**

Loss Factor (%) 6.5100% 6.8200%

Appendix K – Cost Allocation Sheet O1 (Updated)

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$3,596,458	$2,103,256	$531,007	$823,173	$124,292	$14,731
mi	Miscellaneous Revenue (mi)	$291,800	$161,415	$53,106	$64,873	$12,033	$373
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	**$3,888,258**	**$2,264,670**	**$584,113**	**$888,046**	**$136,325**	**$15,104**
	Factor required to recover deficiency (1 + D)	1.0184					
	Distribution Revenue at Status Quo Rates	$3,662,561	$2,141,913	$540,767	$838,302	$126,576	$15,001
	Miscellaneous Revenue (mi)	$291,800	$161,415	$53,106	$64,873	$12,033	$373
	Total Revenue at Status Quo Rates	**$3,954,361**	**$2,303,328**	**$593,873**	**$903,176**	**$138,609**	**$15,375**
	Expenses						
di	Distribution Costs (di)	$732,508	$320,444	$114,908	$264,230	$31,542	$1,384
cu	Customer Related Costs (cu)	$658,415	$469,794	$138,355	$40,299	$9,834	$133
ad	General and Administration (ad)	$959,462	$537,346	$173,428	$219,161	$28,446	$1,080
dep	Depreciation and Amortization (dep)	$695,087	$320,387	$112,535	$242,679	$18,341	$1,145
INPUT	PILs (INPUT)	$2,106	$894	$334	$821	$54	$3
INT	Interest	$336,093	$142,664	$53,234	$130,992	$8,656	$547
	Total Expenses	**$3,383,672**	**$1,791,529**	**$592,795**	**$898,182**	**$96,873**	**$4,293**
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$570,689	$242,244	$90,393	$222,425	$14,698	$929
	Revenue Requirement (includes NI)	$3,954,361	$2,033,773	$683,187	$1,120,607	$111,571	$5,222
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$23,864,504	$11,034,804	$3,966,128	$7,955,155	$865,775	$42,642
gp	General Plant - Gross	$4,603,259	$2,041,136	$744,649	$1,668,218	$141,395	$7,862
accum dep	Accumulated Depreciation	($12,973,203)	($6,205,481)	($2,204,290)	($4,008,156)	($531,234)	($24,041)
co	Capital Contribution	($2,428,141)	($1,289,254)	($430,669)	($572,884)	($130,295)	($5,039)
	Total Net Plant	**$13,066,419**	**$5,581,204**	**$2,075,819**	**$5,042,333**	**$345,640**	**$21,424**
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$20,036,663	$5,189,733	$2,269,703	$12,395,610	$138,248	$43,369
	OM&A Expenses	$2,350,385	$1,327,585	$426,692	$523,689	$69,822	$2,597
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	***$22,387,048***	***$6,517,318***	***$2,696,395***	***$12,919,299***	***$208,070***	***$45,967***
	Working Capital	$2,910,316	$847,251	$350,531	$1,679,509	$27,049	$5,976
	Total Rate Base	**$15,976,736**	**$6,428,455**	**$2,426,350**	**$6,721,842**	**$372,689**	**$27,400**
		Rate Base Input equals Output					
	Equity Component of Rate Base	$6,390,694	$2,571,382	$970,540	$2,688,737	$149,076	$10,960
	Net Income on Allocated Assets	$570,689	$511,799	$1,078	$4,994	$41,736	$11,082
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	**$570,689**	**$511,799**	**$1,078**	**$4,994**	**$41,736**	**$11,082**
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	100.00%	113.25%	86.93%	80.60%	124.23%	294.40%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($66,102)	$230,897	($99,074)	($232,561)	$24,754	$9,882
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$269,555	($89,315)	($217,431)	$27,038	$10,152
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.93%	19.90%	0.11%	0.19%	28.00%	101.11%

Appendix L – Revenue Requirement Work Form (Updated)

	Initial Application	Adjustments	Settlement Agreement
Rate Base			
Gross Fixed Assets (average)	$25,591,525	$448,097	$26,039,622
Accumulated Depreciation (average)	($12,457,078)	($516,124)	($12,973,203)
Allowance for Working Capital:			
Controllable Expenses	2,546,318	($195,933)	$2,350,385
Cost of Power	$19,811,587	$225,076	$20,036,663
Working Capital Rate (%)	13.00%		13.00%
Utility Income			
Operating Revenues:			
Distribution Revenue at Current Rates	$3,573,629	$22,829	$3,596,458
Distribution Revenue at Proposed Rates	$3,801,842	($139,281)	$3,662,561
Other Revenue:			
Specific Service Charges	$108,600	$0	$108,600
Late Payment Charges	$23,400	$0	$23,400
Other Distribution Revenue	$131,604	$22,596	$154,200
Other Income and Deductions	$0	$5,600	$5,600
Total Revenue Offsets	$263,604	$28,196	$291,800
Operating Expenses:			
OM+A Expenses	$2,515,933	($195,933)	$2,320,000
Depreciation/Amortization	$623,869	$71,218	$695,087
Property taxes	$30,385	$0	$30,385
Capital taxes			
Other expenses	$0	$0	$ -
Taxes/PILs			
Taxable Income:			
Adjustments required to arrive at taxable income	($579,843)		($559,206)
Utility Income Taxes and Rates:			
Income taxes (not grossed up)	$826		$1,780
Income taxes (grossed up)	$978		$2,106
Capital Taxes			
Federal tax (%)	11.00%		11.00%
Provincial tax (%)	4.50%		4.50%
Income Tax Credits	$ -		
Capitalization/Cost of Capital			
Capital Structure:			
Long-term debt Capitalization Ratio (%)	56.00%		56.00%
Short-term debt Capitalization Ratio (%)	4.00%		4.00%
Common Equity Capitalization Ratio (%)	40.00%		40.00%
Prefered Shares Capitalization Ratio (%)	0.00%		0.00%
Cost of Capital			
Long-term debt Cost Rate (%)	3.44%		3.61%
Short-term debt Cost Rate (%)	2.08%		2.08%
Common Equity Cost Rate (%)	9.12%		8.93%
Prefered Shares Cost Rate (%)	0.00%		0.00%
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	$ (13,323)	$13,323	$ -

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Rate Base

	Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
Gross Fixed Assets (average)	$25,591,525	$448,097	$26,039,622	$0	$26,039,622
Accumulated Depreciation (average)	($12,457,078)	($516,124)	($12,973,203)	$0	($12,973,203)
Net Fixed Assets (average)	$13,134,447	($68,028)	$13,066,419	$0	$13,066,419
Allowance for Working Capital	$2,906,528	$12,402	$2,918,929	($8,613)	$2,910,316
Total Rate Base	**$16,040,975**	**($55,626)**	**$15,985,349**	**($8,613)**	**$15,976,736**

Working Capital

	Initial Application Filing	Interrogatory Adjustments up to December 3, 2012	Interrogatory Response Filing December 3, 2012	Settlement Adjustments	Settlement Agreement
OM&A Expenses	$2,515,933	($38,809)	$2,477,124	($157,124)	$2,320,000
Property Taxes	$30,385		$30,385	$0	$30,385
Cost of Power	$19,811,587	$134,207	$19,945,794	$90,869	$20,036,663
Workign Capital Base	$22,357,905	$95,398	$22,453,303	($66,255)	$22,387,048
Working Capital Rate%	13.00%		13.00%		13.00%
Working Capital Allowance	**$2,906,528**	**$12,402**	**$2,918,929**	**($8,613)**	**$2,910,316**

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Utility Income

	Initial Application	Adjustments	Settlement Agreement
Operating Revenues:			
Distribution Revenue (at Proposed Rates)	$3,801,842	$139,281	$3,662,561
Other Revenue	$263,604	$28,196	$291,800
Total Operating Revenues	$4,065,446	$111,085	$3,954,361
Operating Expenses:			
OM+A Expenses	$2,515,933	$195,933	$2,320,000
Depreciation/Amortization	$623,869	$71,218	$695,087
Property taxes	$30,385	$0	$30,385
Capital taxes	$ -	$0	$0
Other expense	$ -	$0	$0
Subtotal (lines 4 to 8)	$3,170,187	$124,715	$3,045,472
Deemed Interest Expense	$322,428	$13,665	$336,093
Total Expenses (lines 9 to 10)	$3,492,616	$111,050	$3,381,565
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($13,323)	$13,323	$0
Utility income before income taxes	$586,153	$13,357	$572,795
Income taxes (grossed-up)	$978	$1,128	$2,106
Utility net income	$585,175	($14,486)	$570,689.00

Other Revenues / Offsets

	Initial Application	Adjustments	Settlement Agreement
Specific Service Charges	$108,600	$0	$108,600
Late Payment Charges	$23,400	$0	$23,400
Other Distribution Revenue	$131,604	$22,596	$154,200
Other Income and Deductions	$0	$5,600	$5,600
Total Revenue Offsets	$263,604	$28,196	$291,800

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Taxes/PILs

	Initial Application	Settlement Agreement
Determination of Taxable Income		
Utility net income before taxes	$585,175	$570,689
Adjustments required to arrive at taxable	($579,843)	($559,206)
Taxable income	$5,332	$11,483
Calculation of Utility income Taxes		
Income taxes	$826	$1,780
Gross-up of Income Taxes	$152	$326
Grossed-up Income Taxes	$978	$2,106
PILs / tax Allowance (Grossed-up Income	$978	$2,106
Other tax Credits	$0	$0
Tax Rates		
Federal tax (%)	11.00%	11.00%
Provincial tax (%)	4.50%	4.50%
Total tax rate (%)	15.50%	15.50%

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Capitalization/ Cost of Capital

	Initial Application			
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$8,982,946	3.44%	$309,082
Short-term Debt	4.00%	$641,639	2.08%	$13,346
Total Debt	60.00%	$9,624,585	3.35%	$322,428
Equity				
Common Equity	40.00%	$6,416,390	9.12%	$585,175
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$6,416,390	9.12%	$585,175
Total	100.00%	$16,040,975	5.66%	$907,603

	Per Settlement Agreement			
	(%)	($)	(%)	($)
Debt				
Long-term Debt	56.00%	$8,946,972	3.61%	$322,801
Short-term Debt	4.00%	$639,069	2.08%	$13,293
Total Debt	60.00%	$9,586,041	3.51%	$336,093
Equity				
Common Equity	40.00%	$6,390,694	8.93%	$570,689
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$6,390,694	8.93%	$570,689
Total	100.00%	$15,976,736	5.68%	$906,782

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Revenue Deficiency/Sufficiency:

Particulars	Initial Application		Settlement Agreement	
	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
Revenue Deficiency from Below		$228,213		$66,102
Distribution Revenue	$3,573,629	$3,573,629	$3,596,458	$3,596,458
Other Operating Revenue Offsets - net	$263,604	$263,604	$291,800	$291,800
Total Revenue	$3,837,233	$4,065,446	$3,888,258	$3,954,361
Operating Expenses	$3,170,187	$3,170,187	$3,045,472	$3,045,472
Deemed Interest Expense	$322,428	$322,428	$336,093	$336,093
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($13,323)	($13,323)	$ -	$ -
Total Cost and Expenses	$3,479,293	$3,479,293	$3,381,565	$3,381,565
Utility Income Before Income Taxes	$357,940	$586,153	$506,693	$572,795
Tax Adjustments to Accounting Income per 2013 PILs model	($579,843)	($579,843)	($559,206)	($559,206)
Taxable Income	($221,903)	$6,310	($52,513)	$13,590
Income Tax Rate	15.50%	15.50%	15.50%	15.50%
Income Tax on Taxable Income	($34,395)	$978	($8,139)	$2,106
Income Tax Credits	$ -	$ -	$ -	$ -
Utility Net Income	$392,335	$585,175	$514,833	$570,689
Utility Rate Base	$16,040,975	$16,040,975	$15,976,736	$15,976,736
Deemed Equity Portion of Rate Base	$6,416,390	$6,416,390	$6,390,694	$6,390,694
Income/(Equity Portion of Rate Base)	6.11%	9.12%	8.06%	8.93%
Target Return - Equity on Rate Base	9.12%	9.12%	8.93%	8.93%
Deficiency/Sufficiency in Return on Equity	-3.01%	0.00%	-0.87%	0.00%
Indicated Rate of Return	4.46%	5.66%	5.33%	5.68%
Requested Rate of Return on Rate Base	5.66%	5.66%	5.68%	5.68%
Deficiency/Sufficiency in Rate of Return	-1.20%	0.00%	-0.35%	0.00%
Target Return on Equity	$585,175	$585,175	$570,689	$570,689
Revenue Deficiency/(Sufficiency)	$192,840	($0)	$55,856	$0
Gross Revenue Deficiency/(Sufficiency)	$228,213		$66,102	

Appendix L – Revenue Requirement Work Form (Updated) – Cont'd

Revenue Requirement:

Particulars	Application	Settlement Agreement
OM&A Expenses	$2,515,933	$2,320,000
Amortization/Depreciation	$623,869	$695,087
Property Taxes	$30,385	$30,385
Income Taxes (Grossed up)	$978	$2,106
Other Expenses	$ -	
Return		
Deemed Interest Expense	$322,428	$336,093
Return on Deemed Equity	$585,175	$570,689
Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	($13,323)	$ -
Service Revenue Requirement (before Revenues)	$4,065,446	$3,954,361
Revenue Offsets	$263,604	$291,800
Base Revenue Requirement	$3,801,842	$3,662,561
(excluding Tranformer Owership Allowance credit adjustment)		
Distribution revenue	$3,801,842	$3,662,561
Other revenue	$263,604	$291,800
Total revenue	$4,065,446	$3,954,361
Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)	$ -	$ -

Appendix M – Throughput Revenue (Updated)

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	6,231	6,231	6,230.68	50,241,010		$ 15.23	$ 0.0200		$ 2,143,539.66	$ 2,141,913		$ 2,141,913	-$ 1,626
GS < 50 kW	Customers	755	755	754.60	21,972,649		$ 21.42	$ 0.0158		$ 541,130.75	$ 540,767		$ 540,767	-$ 364
GS > 50 to 4,999 kW	Customers	113	112	112.44	120,000,000	292,641	$ 60.54		$ 3.0849	$ 984,450.75	$ 852,135	$ 132,000	$ 984,135	-$ 316
Large Use				-						$ -			$ -	$ -
Streetlighting	Connections	2,071.5	2,071.5	2,071.53	1,338,353	3,660	$ 3.66		$ 8.4572	$ 121,852.49	$ 121,852		$ 121,852	-$ 1
Sentinel Lighting				-						$ -			$ -	$ -
Unmetered Scattered Load	Connections	12.00	12.00	12.00	419,852		$ 9.90	$ 0.0106		$ 5,875.73	$ 5,893		$ 5,893	$ 18
Standby Power				-						$ -			$ -	$ -
Embedded Distributor Class				-						$ -			$ -	$ -
etc.				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 3,796,849.38	$ 3,662,561	$ 132,000	$ 3,794,561	-$ 2,289