MIDLAND POWER UTILITY CORPORATION

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES

EFFECTIVE MAY 1, 2013

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IN THE MATTER OF the Ontario Energy Board Act, 1998, being Schedule B to the Energy Competition Act, 1998, S.O. 1998, c.15, as amended;

AND IN THE MATTER OF an Application by Midland Power Utility Corporation to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2013.

Title of Proceeding: An Application by Midland Power Utility Corporation for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2013.

Applicants Name: Midland Power Utility Corporation

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P.O. Box 820
Midland, ON
L4R 4P4

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Chief Financial Officer

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President & CEO

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APPLICATION

Introduction

The Applicant is Midland Power Utility Corporation. The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Midland, ON. The Applicant carries on the business of distributing electricity within the Town of Midland.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013. A list of requested approvals is set out below.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2010 (the "Filing Requirements") in order to prepare this application.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Appendix A below and in Exhibit 8. The material being filed in support of this Application sets out Midland Power Utility Corporation's approach to its distribution rates and charges.

Proposed Effective Date of Rate Order

The Applicant requests the OEB make its Rate Order effective May 1, 2013 in accordance with the Filing Requirements.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

The proposed rates, as set out in Appendix A, for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

The proposed and adjusted rates are necessary to ensure Midland Power Utility Corporation has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses, provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

There are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures. Revenue to cost ratio adjustments were made to the Residential customer class in order to reduce bill impacts below 10%.

A new specific service charge proposed by the Applicant includes an Interval Meter load management tool charge of $25.00/month, in addition to those specific service charges previously approved by the Board; and

Such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

The Applicant seeks approval of its Basic Green Energy Plan as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. The Applicant's Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported in EB-2009-0397 – Distribution System Plans under the Green Energy Act issued on December 18, 2009.

Form of Hearing Requested

The Applicant requests that this Application be disposed of by way of a written hearing.

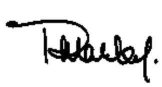
Statement of Publication

Midland PUC submits the local newspaper, the Midland Mirror is the newspaper serving its distribution area and proposes publication in this newspaper of the Notice of Application herein.

DATED at Midland, Ontario, this 31st day of August, 2012

All of which is respectfully submitted,

Midland Power Utility Corporation



Phil Marley, CMA
President & CEO

APPENDIX A

SCHEDULE OF PROPOSED RATES AND CHARGES

Midland Power Utility Corporation

RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges

Effective May 1, 2013

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	14.72
	Distribution Volumetric Rate	per kWh	0.0193
	Low Voltage Rider	per kWh	0.0020
	Stranded Meter Rider	per month	2.63
	Deferral and Variance Account Rider	per kWh	0.0013
GS < 50 kW			
	Monthly Service Charge	per month	22.41
	Distribution Volumetric Rate	per kWh	0.0165
	Low Voltage Rider	per kWh	0.0018
	Stranded Meter Rider	per month	6.67
	Deferral and Variance Account Rider	per kWh	0.0012
GS >50 to 4999 kW			
	Monthly Service Charge	per month	75.06
	Distribution Volumetric Rate	per kW	3.7143
	Low Voltage Rider	per kW	0.7283
	GA Rate Adder/Rider	per month	0.30
	Deferral and Variance Account Rider	per kW	0.4440
Street Lighting			
	Monthly Service Charge	per month	3.87
	Distribution Volumetric Rate	per kW	8.9565
	Low Voltage Rider	per kW	0.5630
	Deferral and Variance Account Rider	per kW	0.4910
Unmetered and Scattered			
	Monthly Service Charge	per month	10.25
	Distribution Volumetric Rate	per kWh	0.0110
	Low Voltage Rider	per kWh	0.0018
	Deferral and Variance Account Rider	per kWh	0.0012
microFIT Generator			
	Monthly Service Charge	per month	5.25

Midland Power Utility Corporation

RATES SCHEDULE (Part 2)

Schedule of Distribution Rates and Charges

Effective May 1, 2013

SPECIFIC SERVICE CHARGES	Calculation Basis	Rate
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
Disconnect/Reconnect at meter - during regular hours	$	65.00
Install/Remove load control device - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Install/Remove load control device - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
Interval Meter Load Managmeent Tool charge	$	25.00
Non-Payment of Account - Late Payment - per month	%	1.50
Non-Payment of Account - Late Payment - per annum	%	19.56

ALLOWANCES	Calculation Basis	Rate ($)
Transformer Allowance for Ownership - kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand and energy	%	(1.00)

RETAIL SERVICE CHARGES	Calculation Basis	Rate ($)
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
Requewst 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 tyhrough the Electronic Business Transaction (EBT) system, apaplied 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	
Supply Facilities Loss Factor (5 year average)	1.0345
Distribution Loss Factor - Secondary Metered Customers < 5,000 kW	1.0326
Distribution Loss Factor - Primary Metered Customers > 5,000 kW	1.0223
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0682
Total Loss Factor - Primary Metered Customer > 5,000 kW	1.0576

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Email jsidlofsky@blgcanada.com

SPECIFIC APPROVALS REQUESTED:

In this proceeding, Midland PUC is requesting the following approvals:

- Approval to charge rates effective May 1, 2013 to recover a revenue requirement of $ 4,065,446 which includes a revenue deficiency of $ 228,213 as set out in Exhibit 6, Tab 1, Schedule 1; the schedule of proposed rates is set out in Exhibit 8, Schedule 6;

- Approval of the proposed loss factor as set out in Exhibit 8, Schedule 6;

- Approval of revised low voltage rates as proposed and described in Exhibit 8, Schedule 1;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Schedule 1;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Midland PUC's 2012 Distribution Rates (EB-2011-0182);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Midland PUC's 2012 Distribution Rates (EB- 2011-0182);

- Approval of a new Specific Service Charge, Interval Meter Load Management Tool charge of $25.00/month as outlined in Exhibit 3;

- Approval to dispose of the following Deferral and Variance Account balances as at December 31 2011 over a one year period using the method of recovery described in Exhibit 9, Tab 1, Schedule 2:

  1508 Other Regulatory Assets - Sub-account Deferred IFRS Transition Costs

1508 Other Regulatory Assets – Sub-account Incremental Capital Charges

1518 Retail Cost Variance Account

1550 Low Voltage Variance

1580 RSVA - Wholesale Market Service Charges

1584 RSVA - Transmission Network

1586 RSVA - Transmission Connection

1588 RSVA - Power

1589 RSVA – Global Adjustment

1592 PILs and Tax Variances for 2006 and Subsequent Years (excludes sub-account and contra account)

1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST

1595 Disposition and Recovery/Refund of Regulatory Balances (2009)

- Approval for a stranded meter rate rider of $2.63 per month per metered residential customer and $6.67 per month per metered General Service <50kW customer, for one year to recover the net book value of $257,116 for stranded meters as at December 31, 2012.

- Approval to realign the Revenue to Cost ratios as detailed in Exhibit 7.

- Approval to continue with #1508 - Other Regulatory Assets - sub-account – Deferred IFRS Transition Costs and sub-account – Incremental Capital Charges to track costs, revenues and interest for amounts to be disposed of in a future rate proceeding.

- Approval to eliminate the Sentinel Light customer class as discussed in Exhibit 8.

- Approval of the Basic Green Energy Plan as set out in Exhibit 2;

- In Midland PUC's 2010 IRM Decision (EB-2009-0236) The Board directed Midland PUC to record in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Midland PUC has complied with this directive and has been recording these amounts as of July 1, 2010. The application Midland PUC is currently submitting is based on budgeted information net of any HST ITCs Midland PUC will receive. As a result, Midland PUC requests approval to discontinue recording these variances as of December 31, 2012.

- In the event the OEB is unable to provide a Decision and Order on the Application before June 1, 2013 for implementation of rates by Midland PUC as of May 1, 2013, Midland PUC requests the OEB issue an Interim Order approving the current distribution rates and other charges, effective May 1, 2013.

PROPOSED ISSUES LIST:

The Applicant would expect, based on previous regulatory experience and other hearings, the following matters pertaining to the 2013 Test Year may constitute issues in this Application:

GENERAL (Exhibit 1)

- Are the Applicant's overall economic and business planning assumptions for the Test Year appropriate?
- Is service quality, based on the Board specified performance indicators, acceptable?
- Is the proposed revenue requirement appropriate?

2. RATE BASE (Exhibit 2)

- Are the Applicant's asset planning assumptions (e.g. asset condition, economic conditions, etc.) appropriate?
- Is the Applicant's capitalization and depreciation policy appropriate?
- Are the capital expenditures appropriate?
- Are the in-service dates accurate for projects closed prior to the Test Year and are they appropriate for proposed projects?
- Is the working capital allowance for the test year appropriate?
- Is the proposed rate base for the test year appropriate?
- Is the accounting for stranded meters appropriate?
- Is the basic Green Energy Plan appropriate?

3. LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

- Is the load forecast methodology including weather normalization appropriate?
- Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?
- Is CDM appropriately reflected in the load forecast?
- Are the proposed revenue offsets appropriate?

4. OPERATING COSTS (Exhibit 4)

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2013 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

5. COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)

- Is the proposed capital structure appropriate?
- Is the cost of debt appropriate?
- Is the proposed return on equity appropriate?

6. CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)

- Is the calculation of Revenue Deficiency accurate?

7. COST ALLOCATION (Exhibit 7)

- Is the Applicant's cost allocation appropriate?
- Are the proposed revenue-to-cost ratios appropriate?

8. RATE DESIGN (Exhibit 8)

- Are the proposed classes of customers appropriate:
- Are the customer charges and the fixed-variable splits for each class appropriate?
- Are the proposed Retail Transmission Service Rates appropriate?
- Are the proposed loss factors appropriate?
- Is the Applicant's proposed Tariff of Rates and Charges appropriate?
- Is the Applicant's rate mitigation plan appropriate?

In preparing this Application, Midland PUC has considered the impact on its customers, with the goal of minimizing those impacts. Customer impacts including percentage average Total Bill Impact are set out in Exhibit 8, Schedule 8, and Appendix A Bill Impacts. Embedded in this monthly bill impact is the effect of revised distribution rates (monthly service charge and volumetric rate), revised Loss Factors, Stranded Meter Rate Rider and Deferral and Variance Account Rate Rider to dispose of the balances in the Deferral and Variance accounts requested in this Application.

9. DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

- Are the account balances, cost allocation methodology and disposition plan appropriate?

Midland PUC is in a debit position in variance Deferral and Variance Accounts. Midland PUC is requesting the disposition of the amounts specified in Exhibit 9 over a one year period, via a rate rider, allocated to all classes. Midland PUC is also requesting a Stranded Meter Rate Rider over one year to recover the stranded meter assets as a result of the implementation of the smart metering infrastructure. Midland PUC has include the Smart Meter Entity charge of $.86 per customer per month to recover the costs of the IESO relating to the smart meter infrastructure.

PROCEDURAL ORDERS/MOTIONS/NOTICES:

On January 26, 2012 the Board issued its list of distributors that it anticipates will be filing a Cost of Service Application for 2013. Midland PUC was included on that list.

ACCOUNTING ORDERS REQUESTED:

Midland PUC is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS:

Midland PUC has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

Midland PUC has filed trial balances, financial statements and forecasted results for the 2012 bridge year, 2013 Test Year and all proceeding years in accordance with Canadian Generally Accepted Accounting Principles (GAAP).

Proforma financial statements and forecasted results of Midland PUC's 2012 Bridge Year and 2013 Test Year are reported in accordance with the proposed modified International Financial Reporting Standards (IFRS) in compliance with the Board's direction.

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM:

Description of Distributor:

COMMUNITY SERVED:	Town of Midland
TOTAL SERVICE AREA:	20 sq km
RURAL SERVICE AREA:	none
DISTRIBUTION TYPE:	Electricity distribution
MUNICIPAL POPULATION:	17,000
POPULATION OF URBAN AREAS SERVED:	16,000

A map of Midland PUC’s Distribution Service Territory accompanies this Schedule as Appendix B.

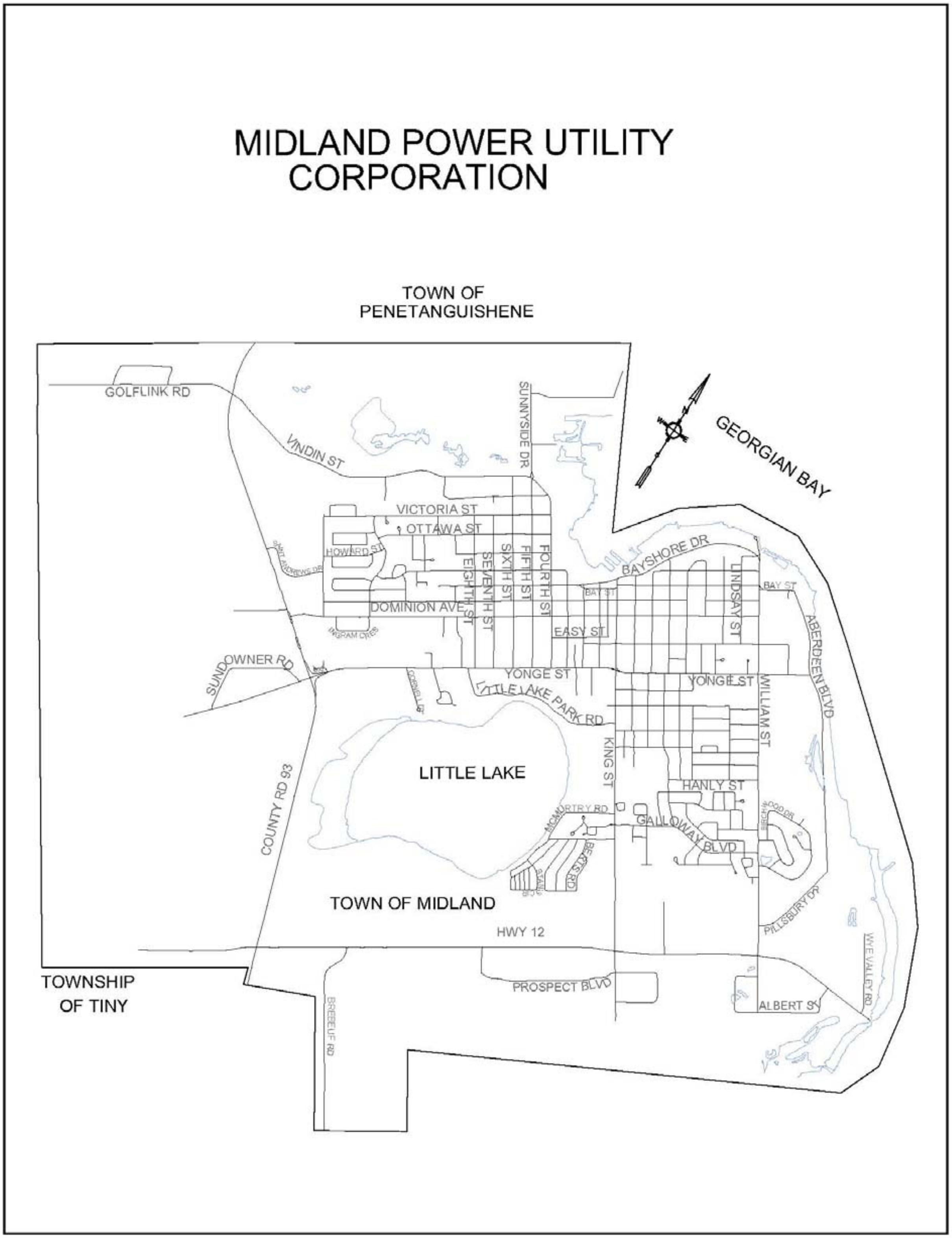
A schematic diagram of Midland PUC’s distribution system is attached in Appendix C.

MAP OF DISTRIBUTION SERVICE TERRITORY:

The outlined area represents Midland PUC's Distribution Service Territory.

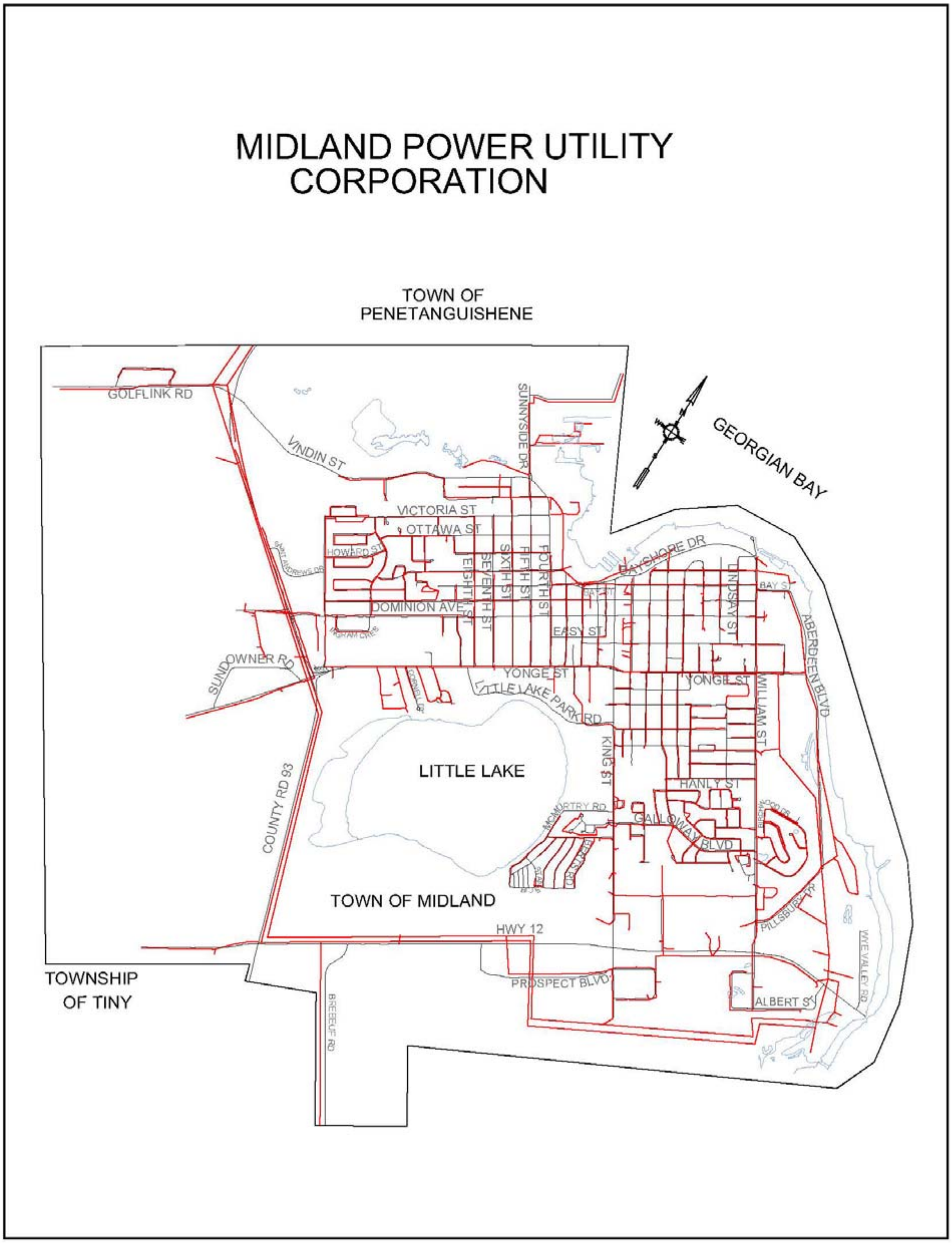
APPENDIX B

MAP OF DISTRIBUTION SERVICE TERRITORY


MIDLAND POWER UTILITY CORPORATION
TOWN OF PENETANGUISHENE
GOLFLINK RD
VINDIN ST
SUNNYSIDE DR
GEORGIAN BAY
VICTORIA ST
OTTAWA ST
HOWARD ST
BAYSHORE DR
EIGHTH ST
SEVENTH ST
SIXTH ST
FIFTH ST
FOURTH ST
LINDSAY ST
BAY ST
DOMINION AVE
ABERDEEN BLVD
EASY ST
SUNDOWNER RD
YONGE ST
LITTLE LAKE PARK RD
WILLIAM ST
KING ST
LITTLE LAKE
COUNTY RD 93
HANLY ST
GALLOWAY BLVD
TOWN OF MIDLAND
PILLSBURY DR
HWY 12
WYE VALLEY RD
TOWNSHIP OF TINY
PROSPECT BLVD
ALBERT ST
BREBEUF RD

APPENDIX C

MAP OF DISTRIBUTION SYSTEM


MIDLAND POWER UTILITY CORPORATION
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OTTAWA ST
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EIGHTH ST
SEVENTH ST
SIXTH ST
FIFTH ST
FOURTH ST
LINDSAY ST
BAY ST
DOMINION AVE
EASY ST
ABERDEEN BLVD
SUNDOWNER RD
YONGE ST
LITTLE LAKE PARK RD
WILLIAM ST
KING ST
LITTLE LAKE
COUNTY RD 93
HANLY ST
GALLOWAY BLVD
TOWN OF MIDLAND
HWY 12
PILLSBURY DR
WYE VALLEY RD
TOWNSHIP OF TINY
PROSPECT BLVD
ALBERT ST
BREBEUF RD

LIST OF NEIGHBOURING UTILITIES:

Hydro One Networks Inc.
483 Bay Street
South Tower, 10th Floor
Toronto, ON
M5G 2P5

PowerStream Inc.
161 Cityview Boulevard
Vaughan, ON
L4H 0A9

Newmarket-Tay Power Distribution Ltd.
590 Steven Court.
Newmarket, Ontario
L3Y 6Z2

EXPLANATION OF HOST AND EMBEDDED UTILITIES:

Midland PUC is embedded to Hydro One. Midland PUC is a registered Market Participant dealing directly with the IESO and has one metering point metered by Hydro One. Consequently, Midland PUC deals with both the IESO and with Hydro One for the purchase of electricity which is passed through to our customers. As an embedded utility, Midland PUC is billed monthly by Hydro One for Transmission and Low Voltage Charges.

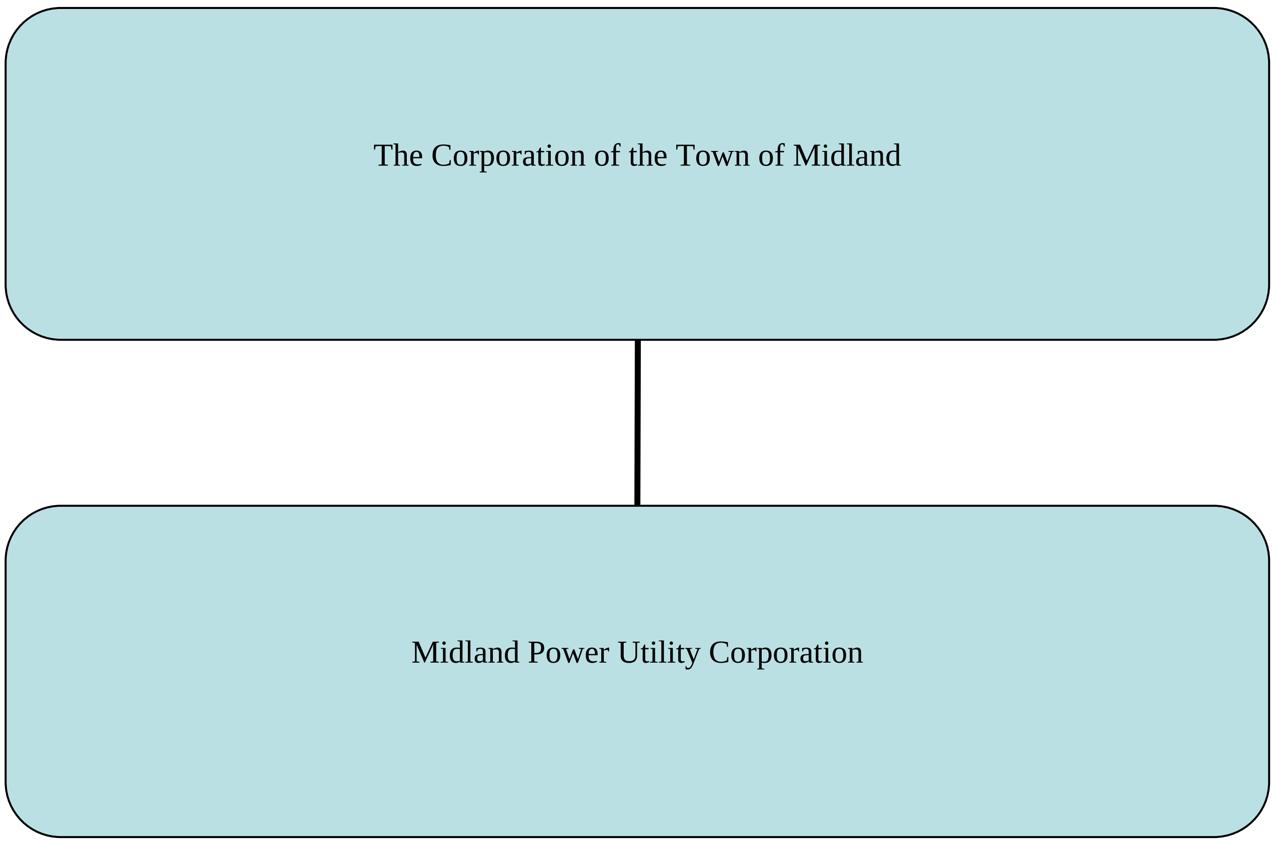
Midland PUC does not host any utilities within its service area.

UTILITY ORGANIZATIONAL STRUCTURE:

Midland PUC is 100% owned by its parent company the Corporation of the Town of Midland. A chart illustrating Midland PUC's corporate family is provided at Exhibit 1, Tab 1, Schedule 13.

CORPORATE ENTITIES RELATIONSHIP CHART:

A chart illustrating the Corporate Entities Relationships is as follows:



PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE:

No changes to Midland PUC's corporate and operational structures are planned at the present time.

CONDITIONS OF SERVICE

There are no changes to Midland PUC's Conditions of Service which have been filed with the Ontario Energy Board and are publically available on Midland PUC's website. There are no changes to the Conditions of Service which would result once this COS Application is approved.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS:

Directive from 2009 Cost of Service Application (EB-2008-0236):

The Board prescribed a phase-in period to adjust its revenue-to-cost rates, moving the Sentinel Lighting and Street Lighting from their 2009 positions to the bottom of the Board's target ranges during 2009 and 2010. Midland PUC has complied with this directive and as of its 2010 IRM application (EB-2009-0236), Sentinel Lighting and Street Lighting Revenue-to-Cost Ratios have been moved to within the Board's target ranges.

PRELIMINARY LIST OF WITNESSES:

While Midland PUC requests this Application be disposed of by way of a written hearing. Should a technical conference or an oral hearing be necessary, Midland PUC will provide a list of potential witnesses as required.

SUMMARY OF THE APPLICATION:

Preamble

Midland PUC is an electricity distribution company licensed by the OEB to provide electricity distribution services to its customers in the Town of Midland. Current rates will result in actual Return on Equity in 2012 and 2013 below levels currently approved by the OEB. The increased rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.
2) Continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance.
3) Maintain staffing requirements, including training and preparing for succession planning.
4) To provide a reasonable rate of return to the Shareholder.

Midland PUC's priorities are defined in its Corporate Goals:

> *Midland PUC is committed to delivering value to its customers by providing a reliable service at competitive rates, which playing an important role in promoting energy conservation in our community.*

> *Midland PUC is also committed to providing our customers with reliable energy while providing a safe reliable and trusted electricity distribution system. We will not allow our employees' safety to be compromised at any cost.*

Purpose and Need

Midland PUC's requested revenue requirement for 2013 in the amount of $ 4,065,446 includes the recovery of its costs to provide distribution services, its permitted Return on Equity ["ROE"] and the funds necessary to service its debt.

When forecasted energy and demand levels for 2013 are considered, Midland PUC estimates its present rates will produce a deficiency in gross distribution revenue of $ 228,213 for the 2013 Test Year. If this deficiency continues, Midland PUC will not be able to sustain current capital investments, staffing requirements and the maintenance required to ensure a safe and reliable distribution system.

Therefore, Midland PUC seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover the projected revenue requirement and other relief sought are set out in Exhibit 1, Tab 1, Schedule 2, Appendix A and Exhibit 8, Schedule 6 to this Application.

The information presented in this Application represents Midland PUC's forecasted results for its 2013 Test Year. Midland PUC is also presenting the forecasted results for 2012 Bridge Year and audited financial information for fiscal 2009, 2010 and 2011.

Midland PUC is an urban LDC servicing the Town of Midland with a total service area of 20 sq km, servicing 16,000 residents in a municipal population of approximately 17,000, with a summer peaking load and a customer base of approximately 7,100 electric customers. The distribution plant presently consists of a sub-transmission network at 44kV, municipal sub-stations at 8.3kV and 4.16kV. In 2013, Midland PUC is upgrading a 4.16 KV substation. This station is the last to be upgraded to new arc-proof design in accordance with a Substation Study completed in 2006 and updated in 2011.

Midland PUC continues to expand and reinforce its distribution system in order to meet the demand of all customers in its service territory. Expenditures are also made to meet the regulations set out by the Ministry of Energy, the OEB, the IESO and other regulatory bodies.

Timing

The financial information supporting the Test Year for this Application will be Midland PUC's fiscal year ending December 31, 2013 (the "2013 Test Year"). However, Midland PUC is requesting rates effective May 1, 2013, continuing through April 30, 2014.

Customer Impact

In preparing this application, Midland PUC has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Midland PUC notes only the Unmetered Scattered Load and Street Lighting classes fall outside the applicable threshold defined by the Board in the March 31, 2012 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2011-0219). In this application the Unmetered Scattered Load and Street Lighting classes have been brought within the Board's threshold with minimal impact to other classes. Rate mitigation has been adopted with respect to the Residential class in order to bring total bill impacts to below 10% as required by the Ontario Energy Board. In order to accomplish this, the Residential class revenue to cost ratio has been reduced from 109.17% to 101.5%. The reduction in revenue from the Residential class has been allocated to the General Service <50kW and General Service >50kW classes in order to maintain revenue neutrality and to bring their cost allocation ratios closer to 1.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised low voltage rates, revised retail transmission rates, revised loss factors, Stranded Meter rate rider, and regulatory asset rate rider to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out in Table 1.2.1 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Appendix A.

Transition to Modified International Financial Reporting Standards (MIFRS)

Consistent with the Board's letter issued April 30, 2012 entitled *Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board*, this application has been prepared using modified IFRS (MIFRS). The forecasted 2013 Test Year has been prepared under MIFRS with comparables to the 2012 Bridge Year which has been presented under Canadian Generally Accepted Accounting Principles (CGAAP) and MIFRS.

The transition to MIFRS has impacted the calculation of depreciation rates only since Midland PUC's capitalization policy under CGAAP complies with IFRS standards. This change has impacted the 2013 rate base and the 2013 distribution revenue requirement. Midland PUC has provided detailed explanations of this change in the applicable section of the application.

Table 1.2.1: Bill Impacts – Residential and General Service <50kW

Customer Class: **Residential**

Consumption 800 **kWh** ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 3

	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	$ 14.7200	1	$ 14.72	$ 2.94	24.96%
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	$ 0.0193	800	$ 15.44	-$ 0.24	-1.53%
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			$ 30.16	**$ 0.44**	**1.48%**
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	$ -	$ 2.6307	1	$ 2.63	$ 2.63	
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**			**$ 35.44**	**$ 10.12**	**39.97%**
RTSR - Network	per kWh	$ 0.0057	852	$ 4.86	$ 0.0055	855	$ 4.69	-$ 0.17	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0047	852	$ 4.00	$ 0.0045	855	$ 3.87	-$ 0.14	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.18**			**$ 44.00**	**$ 9.81**	**28.71%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	852	$ 4.43	$ 0.0052	855	$ 4.44	$ 0.01	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	852	$ 0.94	$ 0.0011	855	$ 0.94	$ 0.00	0.32%
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		$ 0.8600	1	$ 0.86	$ 0.86	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	252	$ 22.18	$ 0.0880	255	$ 22.42	$ 0.24	1.08%
TOU - Off Peak		$ 0.0650	545	$ 35.45	$ 0.0650	547	$ 35.56	$ 0.11	0.32%
TOU - Mid Peak		$ 0.1000	153	$ 15.34	$ 0.1000	154	$ 15.39	$ 0.05	0.32%
TOU - On Peak		$ 0.1170	153	$ 17.94	$ 0.1170	154	$ 18.00	$ 0.06	0.32%
Total Bill on RPP (before Taxes)				**$ 112.58**			**$ 123.51**	**$ 10.93**	**9.71%**
HST		13%		$ 14.64	13%		$ 16.06	$ 1.42	9.71%
Total Bill (including HST)				$ 127.22			$ 139.57	$ 12.35	9.71%
Ontario Clean Energy Benefit [1]				-$ 12.72			-$ 13.96	-$ 1.24	9.75%
Total Bill on RPP (including OCEB)				**$ 114.50**			**$ 125.61**	**$ 11.11**	**9.70%**
Total Bill on TOU (before Taxes)				**$ 114.13**			**$ 125.04**	**$ 10.91**	**9.56%**
HST		13%		$ 14.84	13%		$ 16.26	$ 1.42	9.56%
Total Bill (including HST)				$ 128.97			$ 141.29	$ 12.33	9.56%
Ontario Clean Energy Benefit [1]				-$ 12.90			-$ 14.13	-$ 1.23	9.53%
Total Bill on TOU (including OCEB)				**$ 116.07**			**$ 127.16**	**$ 11.10**	**9.56%**

Loss Factor (%)	6.5100%	6.8500%

Table 1.2.1: Bill Impacts – Residential and General Service <50kW (con'd)

Customer Class: **General Service Less Than 50KW**

Consumption **2000** **kWh** ○ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 14.8600	1	$ 14.86	$ 22.4100	1	$ 22.41	$ 7.55	50.81%
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	$ 0.0165	2000	$ 33.00	$ 2.00	6.45%
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			$ 55.41	**-$ 2.36**	**-4.09%**
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	$ -	$ 6.6685	1	$ 6.67	$ 6.67	
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**			**$ 68.05**	**$ 17.28**	**34.05%**
RTSR - Network	per kWh	$ 0.0052	2130	$ 11.08	$ 0.0050	2137	$ 10.69	-$ 0.39	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2130	$ 9.16	$ 0.0041	2137	$ 8.85	-$ 0.31	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 71.01**			**$ 87.59**	**$ 16.58**	**23.36%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	2130	$ 11.08	$ 0.0052	2137	$ 11.11	$ 0.04	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	2130	$ 2.34	$ 0.0011	2137	$ 2.35	$ 0.01	0.32%
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				$ 0.8600	1	$ 0.86	$ 0.86	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1530	$ 134.66	$ 0.0880	1537	$ 135.26	$ 0.60	0.44%
TOU - Off Peak		$ 0.0650	1363	$ 88.62	$ 0.0650	1368	$ 88.90	$ 0.28	0.32%
TOU - Mid Peak		$ 0.1000	383	$ 38.34	$ 0.1000	385	$ 38.47	$ 0.12	0.32%
TOU - On Peak		$ 0.1170	383	$ 44.86	$ 0.1170	385	$ 45.01	$ 0.14	0.32%
Total Bill on RPP (before Taxes)				**$ 278.33**			**$ 296.42**	**$ 18.09**	**6.50%**
HST		13%		$ 36.18	13%		$ 38.53	$ 2.35	6.50%
Total Bill (including HST)				$ 314.52			$ 334.95	$ 20.44	6.50%
Ontario Clean Energy Benefit [1]				-$ 31.45			-$ 33.50	-$ 2.05	6.52%
Total Bill on RPP (including OCEB)				**$ 283.07**			**$ 301.45**	**$ 18.39**	**6.50%**
Total Bill on TOU (before Taxes)				**$ 270.50**			**$ 288.53**	**$ 18.04**	**6.67%**
HST		13%		$ 35.16	13%		$ 37.51	$ 2.34	6.67%
Total Bill (including HST)				$ 305.66			$ 326.04	$ 20.38	6.67%
Ontario Clean Energy Benefit [1]				-$ 30.57			-$ 32.60	-$ 2.03	6.64%
Total Bill on TOU (including OCEB)				**$ 275.09**			**$ 293.44**	**$ 18.35**	**6.67%**

Stranded Meters:

Midland PUC is also requesting the recovery of stranded meter amounts as outlined in Exhibit 9 of this Application.

Capital Structure

Midland PUC is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt, 56% Long Term Debt.

Midland PUC completed its transition to a capital structure of 60% debt and 40% equity through its 2010 IRM Rate Application. Midland PUC plans to maintain its current capital structure and has prepared this rate application with a deemed capital structure of 56% Long Term Debt, 4% Short Term Debt and 40% Equity to comply with the Report of the Board on Cost of Capital for Ontario Regulated Utilities, March 3, 2011.

Midland PUC has assumed a return on equity of 9.12% consistent with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. Midland PUC understands the OEB will be finalizing the return on equity for 2013 rates based on January, 2013 market interest rate information.

Midland PUC's long term debt is held by Infrastructure Ontario at an average rate of 3.44%.

Midland PUC is requesting a return on Short Term Debt for the 2013 test year of 2.08% consistent with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. Midland PUC understands the OEB will be finalizing the return on equity for 2013 rates based on January, 2013 market interest rate information.

Midland PUC's use of the Return on Equity of 9.12% and Short Term Debt of 2.08% is without prejudice to any revised ROE and Debt Rate adopted by the OEB in early 2013.

With respect to the long term debt, Midland PUC will be applying to Infrastructure Ontario for additional debt financing in 2012 and 2013. Midland PUC has estimated the rates to be charged on the new long term debt at 2.14% and 2.78% based on current rates from Infrastructure Ontario.

Return on Equity

Midland PUC has assumed a return on equity of 9.12% consistent with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012. Midland PUC understands the Board will be finalizing the cost of capital parameters for 2013 rates based on January 2013 market interest rate information, and that adjustments to the Application may be required as a result.

Capital Expenditures

Midland PUC continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. Expenditures are also being made to meet regulations set out by both the OEB, ESA, IESO and other governmental/regulatory organizations

BUDGET OVERVIEW:

Midland PUC compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2012 Bridge Year and the 2013 Test Year.

Revenue Forecast

Midland PUC's energy sales and revenue forecast model was updated to reflect more recent information. This model was then used to prepare the revenue sales and throughput volume and revenue forecast at existing rates for fiscal 2012 and 2013. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as average weather conditions and economic conditions in the area serviced by Midland PUC.

Midland PUC’s service area growth has been very low due to the current economic downturn and conservation measures. For example, in June 2012 a local manufacturer will be shutting down its operations in the Town of Midland. The load forecast model and Operating Revenue calculations are included in Exhibit 3.

Operating Maintenance and Administration (“OM&A”) Expense Forecast

The OM&A expenses for the 2012 Bridge Year and the 2013 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation. In 2012, Midland PUC has included the full costs of implementation of the smart metering infrastructure and in 2013 has included the full costs of the transition to International Financial Reporting Standards (IFRS).

The proposed OM&A expenditures are forecasted to be **$ 2,515,933**. The increase is predominately due to labour and benefit costs attributed to a number of factors including, increased "overhead" required to implement and maintain regulatory compliance and administer a broad range of initiatives such as smart meters, time of use billing, International Financial Reporting Standards (IFRS), succession planning, along with changes to the Distribution System Code and Retail Settlement Code. These regulatory initiatives and employee demographics are placing additional challenges on utilities in relation to the maintenance of effective and cost efficient operations.

Operating costs represent the annual expenditures required to sustain Midland PUC's distribution operations. Midland PUC follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. A summary of Midland PUC's operating costs for the 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in accordance with the Filing Requirements, is provided in Table 4.2.2 Below:

Table 4.2.2: Summary of OM&A Expenses

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge Year (MIFRS)	2013 Test (MIFRS)
Operations	$ 455,700	$ 325,787	$ 191,621	$ 228,798	$ 349,599	$ 349,599	$ 378,987
Maintenance	$ 353,900	$ 337,863	$ 436,383	$ 440,148	$ 457,389	$ 457,389	$ 548,841
Billing & Collecting	$ 435,800	$ 434,238	$ 414,278	$ 239,980	$ 479,686	$ 479,686	$ 498,599
Community Relations	$ 5,600	$ 1,316	$ 3,900	$ 3,728	$ 3,527	$ 3,527	$ 4,450
Administrative & General	$ 814,150	$ 689,371	$ 801,674	$ 879,150	$ 930,199	$ 930,199	$ 1,085,056
TOTAL OM&A EXPENSE	**$ 2,065,150**	**$ 1,788,575**	**$ 1,847,857**	**$ 1,791,803**	**$ 2,220,400**	**$ 2,220,400**	**$ 2,515,933**
Year over Year % Increase		-13.39%	3.31%	-3.03%	23.92%	23.92%	13.31%
Inflation Rate			1.40%	3.29%	1.93%		

OM&A costs in the table above do not include property taxes, however, do represent Midland PUC's integrated set of asset maintenance and customer service activity to meet public and employee safety objectives; to comply with the Distribution System Code, the Standard Supply Service Code and Retail Settlement Code; environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. Midland PUC's expenses in 2013 will rise $ 450,783 over the 2009 Board Approved forecast. This represents an average 5.5% increase per year. As will be discussed in Exhibit 4, the bulk of this increase is due to costs related to the smart meter and IFRS initiatives, succession planning and regulatory compliance requirements.

One of the major issues facing Midland PUC is the hiring of employees. Under current trends, Midland PUC is facing an insufficient supply of skilled, industry savvy and knowledgeable workers. This gap will exist at both the administrative and operations departments. Midland PUC has endeavoured to retain employees, however, past experience has shown that one of the main reasons employees have left Midland PUC's employ is due to the lack of payment of comparable wages. Over the past few years, Midland PUC has started to address this wage inequity and as part of our ongoing process, we will need to pay market rate wages.

Midland PUC has taken the proactive approach to succession planning which has resulted in the identification of employees who will be seeking retirement over the next few years. Employees who have potential to replace managerial employees were also identified. Any promotion of these employees will create additional staff movement and a domino effect throughout the organization. In response to the changing environment and to ensure Midland PUC has a sustainable, skilled and knowledgeable staff, Midland PUC has focused its planning to sustain current positions, transfer expertise to new employees and to ensure business needs are accomplished in this highly regulated environment.

In 2010 two long-term union employees (35 years) in the administrative department retired. Midland PUC's unionized employee complement in this department is three. Consequently, it was necessary to employ an overlapping period where the new employee could gain the expertise of the retiree prior to the retirement to ensure the effective and efficient operations of the administrative department continue. Midland PUC proposes to continue with this overlap process as it looks to the replacement of retiree positions.

As indicated above, Midland PUC will continue to experience a significant increase in the number of employees eligible and expected to retire over the next few years. Additional attrition factors including resignations, disabilities and other health related issues will also contribute to labour and knowledge shortage. Midland PUC has identified four of the nine operations staff may retire over the next few years. These retirements include the Operations Office Manager (sole occupant), one of four linecrew, one metering technician (sole occupant) and one engineering technician (sole occupant). Midland PUC has also identified one senior management position who is also approaching retirement. This represents over 30% of Midland PUC's employee base.

The increased actual and impending retirements at Midland PUC, the work requirements associated with Midland PUC's Asset Management Plan, IFRS implementation, Smart Meter implementation, infrastructure projects which are substantially completed by Midland PUC staff, regulatory and external environment requirements, along with the time period required to become conversant with industry and Midland PUC business practices, has resulted in Midland PUC's proactive approach to ensuring staff will be in place to sustain operating a safe and reliable distribution system.

With the impending retirements coupled with the increases in regulatory and external environmental requirements, the loss of corporate knowledge current employees have through the number of years working and implementing written documents, policies and procedures and the on-the-job experiences will have a huge impact on Midland PUC's ability to provide safe and reliable power to customers and will also prove to have a detrimental impact on productivity, regulatory compliance and safety levels. Midland PUC has identified the following issues that will play a role in the effective management of sustaining our staffing levels:

1. Midland PUC's distribution system has undergone significant upgrading and renewal since 2007, both through planning with the assistance of the Substation Study completed in 2006, the Load Study in 2010 and through governmental mandate planning including, the Smart Meter Infrastructure implementation in 2009/2010 and IFRS transition in 2011-2013. Midland PUC's staff maintain a large depository of knowledge in Midland PUC's distribution system. In particular, three of the five potential retirees have been with the company for 25 years. The fourth and fifth retiree have been with the company

for over 10 years. Their knowledge has been gained through years of practical experience which has developed through various learning environments, including apprenticeships, mentoring, job shadowing and general practices. This type of knowledge is based more on personal experiences and is difficult to transfer to the next incumbent if the proper overlap periods are not in place.

2. With the aging staff complement, new employees are being brought onboard to replace those that are leaving due to retirements and other forms of attrition. Without a proactive approach to ensure the necessary transfer of this expertise, such as overlap periods between new and old employees to assist in the transfer of job specifics and background information, the accumulated years of experience that the older staff have, will not be sustained within the new employee.

3. New technologies designed to improve business delivery also impact Midland PUC's business operations. Today's business requires employees who are adept to change and have the technological ability to implement these requirements. For example, the need for staff to be computer literate is becoming an industry norm. Field workers will need to communicate electronically with the operations centre and as such will need to have the experience and ability to implement changes to their daily work environments to accommodate this technical skill.

4. Midland PUC's proactive approach to ensuring new staff are provided with a mentor for key positions prior to retirements occurring allows for overlap between the existing incumbent and new employee. There will be a continued need for staff that are both experienced and knowledgeable and that are also capable of operating legacy systems.

By adopting this strategy, Midland PUC can ensure the knowledge, skills and corporate practices are passed on to the new employees with a goal of providing a seamless transition. Without this implementation, Midland PUC is at risk of losing significant corporate business practices, productivity will decline as the new employees will endeavour to recreate or reinvent the wheel and Midland PUC's business will suffer increased risk to business continuity, along with a loss of inhouse expertise. Customers will ultimately pay the price for this lack of knowledge and planning as service levels will ultimately decrease.

The benefits of investing these additional resources include, increased organizational innovations and efficiencies, more formalized approach ensuring Midland PUC's business practices and policies are maintained and provided to the new employees and increased overall operational performance.

5. As indicated above, five positions have been identified for replacement over the next few years. This represents over 30% of Midland PUC's workforce. In order to ensure a safe, reliable distribution system is maintained for customers, Midland PUC will require one additional person be hired in 2013. This person would be slated to assist in the operations centre, becoming familiar with operations planning, design and maintenance of our systems. This person would be seconded to replace one of the two operations centre pending retirements. This overlap and expertise shift will take at least one year at which time the person will become a viable, contributing employee. In determining the period of overlap, Midland PUC is cognizant of the importance of the positions to its business operations and the type of knowledge that must be transferred. Once this person has become fully integrated and a retirement is taken, the next person will be hired to backfill the next pending retirement.

Midland PUC also sees the need in 2013 to incorporate a new position - Regulatory Analyst into its staffing complement. Midland PUC recognizes the need to keep current with industry and regulatory requirements along with investing in the distribution infrastructure to provide customers with a safe and reliable system. This new position will be instrumental to Midland PUC's ability to provide rate application, IRM, load and LRAM reporting, RRR filing and other regulatory needs in future years as technical and operational expertise is transferred. Currently, the bulk of the rate applications and IRM filings are completed by industry consultants and inhouse recourses including, the current President and CEO who looks to retire over the next five years. The knowledge required to complete these regulatory requirements will need to be downloaded to the new incumbent, once they have had a significant amount of time to become conversant with industry standards, regulations and processes, including IRM and RRR filings. It is expected the Regulatory Analyst will play an important role in the next Cost of Service Application and along with that, it is planned the use of consultants will be reduced as inhouse expertise will be available. Without this addition, Midland PUC runs the risk of not being in a position to provide regulatory compliance. This position is unique to Midland PUC's business which will provide customers with the ability to continue to rely on Midland PUC to provide just and reasonable rate structure, taking into consideration both financial and operational needs.

The fast pace of the changing environment and its associated shifting business requirements has a major impact on Midland PUC's employees, its complement, required abilities, skills and knowledge and has created the need for additional dedicated resources in the regulatory area of the business environment.

Since 2009, Midland PUC has undergone other attrition factors including retirements, disabled employees, an employee death, and employees who have left the company. Over the past few years, Midland PUC undertook to strengthen its capacity in key support areas in order to better meet its business objectives and priorities, better support the operations of the business, and ensure compliance with requirements and sustainability of the business. The Administrative and Operations functions were improved to ensure Midland PUC's ability to deliver on key initiatives with respect to the sustainability of its staff, smart meter infrastructure, IFRS implementation, emergency preparedness, business continuity, financial, and internal and external communications. As well, increased legislative and program requirements in these areas, including those related to the International Financial Reporting Standards, smart meter infrastructure, changes to health and safety and environmental legislation, labour relations, and customer relations necessitated that these functions be supplemented.

Over the past number of years, Midland PUC has had substantial turnover in the operations department. In 2008, two positions became vacant – Operations Engineering Manager and lineman. One position was filled with a contract lineman, the other was filled with a senior manager. In 2009, the Operations Manager left the company. This position was filled in early 2010, however, was then replaced in late summer as the first incumbent left the company. In late 2010, the senior manager who was hired in 2008 passed away quite suddenly. This position was not filled until mid- December, 2011. The contract lineman position became vacant in 2011 and remains vacant at the time of filing this Cost of Service Application.

6. The increasingly complex regulatory environment and mandated deliverables, the requirement of the organization to deliver on the asset management plan, infrastructure projects, the implementation of International Financial Reporting Standards and smart meter infrastructure implementation have all created a need for additional staff resources to support the delivery of these concurrent multiple objectives. Now that Midland PUC has these plans in place, they must be monitored and maintained. Technical and expert staff will be needed to accomplish this goal which will be to the benefit of all customers.

Midland PUC will continue to experience the effect of the changing landscape in which it operates, including experiencing the full impact of employee demographics and the associated loss of highly skilled, experienced and knowledgeable employees due to retirements and industry requirements. The responses to this rapidly changing environment if not proactive and meaningful will inevitably hamper the continued successes of Midland PUC and challenge the organization’s ability to fulfill its responsibilities to its customers. Midland PUC must maintain and ensure that the current level of its business is sustained throughout these changing times by ensuring that it has a sufficient, sustainable and a prepared staff.

With the above plan in place, Midland PUC will be in a position to manage the effect of these changes and ensure the appropriate resources are in place to meet the long term needs of the business and its customers.

Midland PUC works toward maintaining high levels of efficiencies in a setting of increasing costs. Despite these economic realities, Midland PUC seeks ways to improve efficiencies in our business operations. Midland PUC has attained efficiencies by the pooling of resources and building a strong knowledge based environment with three organizations – Cornerstone Hydro Electric Concepts Inc. (CHEC Group); and Utility Collaborative Services Inc. (UCS) and Utility Standards Forum (USF).

The CHEC Group is an association of 12 LDCs, modeled after a cooperative to combine resources and competencies to best meet the requirements of the changing electrical industry. The CHEC Group is committed to exceeding expectations through the sharing of services, opportunities, knowledge and resources.

Utility Collaborative Services Inc. (UCS) is a billing and service corporation created to provide members with reliable cost-competitive long term software and service solutions. Midland PUC is one of 9 LDCs who work collaboratively on standardization of systems leading to major cost savings for each other. UCS members believe by working together economies and efficiencies can be attained through negotiating preferential agreements with vendors. The UCS business model provides the LDCs with a unique opportunity to become part of an environment that provides a stable operational foundation, and allows utilities to work together and benefit from collective buying pools and agreed-upon standards related to their daily activities.

What makes the UCS business model distinctive from other vendors is that the UCS customers are actually the shareholders of the company. By offering a technology solution in this manner, the “middle man” is eliminated from the equation which results in cost savings that are passed directly back to each owning utility. In addition to the financial benefits, the shareholders of the company are able to benefit from best practice business processes that are shared among the group. Aggregated pricing in the initial purchase of the software solution is a key feature of working with UCS; however, the hosting of the ASP Service that is part of the initiative provides an even greater value as the technical management of the system is part of the package that is offered by UCS.

Utility Standards Forum (USF) provides operational standards for the building of infrastructure in Midland PUC's distribution system in accordance with ESA Standards. Midland PUC is one of over 45 member LDCs throughout Ontario who have worked collaboratively in the design of ESA approved standards, technical networking and standards training for our operations staff. Collaboration and troubleshooting with other LDCs on regulatory requirements and other common objectives is mutually beneficial, reducing the duplication of effort, while creating shared best practices.

Midland PUC's proposed revenue requirement is in the amount of $ 4,065,446 which includes a revenue deficiency of $ 228,213 based on current rates. By comparison, the OEB approved revenue requirement from Midland PUC's 2009 Cost of Service Application was approximately, $3.4M with a revenue deficiency of $758k.

The estimated average distribution revenue per customer in 2010 was $516 which is well below the industry average of $637. Midland PUC is forecasting the 2013 average distribution revenue per customer to be $ 536 which remains below the industry average of 2010 as reported in the OEB 's Yearbook of Electricity Distributors. Midland PUC OM&A per customer for 2010 was $272 well below the industry average of $290 and well below the average cohort of $298 as reported in the OEB's Yearbook of Electricity Distributors. Midland PUC's 2013 OM&A of **$ 354.45** per customer, although provides for increases in year over year expenses, includes all costs relating to the smart metering infrastructure and implementation of IFRS accounting functions. Consequently, the 2013 OM&A per customer is not directly comparable to the stats in 2010.

Capital Budget

The capital budget forecast 2012 and 2013 is influenced by, among other factors, the highest priority capital requirements and Midland PUC's capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of their capital budget priority and are outlined in Exhibit 2, Tab 3.

Midland PUC has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. Midland PUC completes ground inspections throughout the year while completing maintenance on the distribution system. In addition, Midland PUC relies on the substation study completed in 2006 that has provided a comprehensive analysis of the substation infrastructure within Midland PUC's distribution area. Midland PUC's distribution system includes six substations, four of which were over 50 years old and were in need of replacement due to their age. The replacement of these substations took place over the years 2007 through to 2010. The substation study report was updated in 2011 which provided recommendations for the remaining two substations. These upgrades will take into consideration the potential for future growth, however, the replacement is undertaken due to the aging infrastructure and redundancy.

Midland PUC has an obligation to serve new growth within our service area in a timely and cost effective way. In order to fulfill this obligation, Midland PUC identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. This is the prudent approach to planning since it ensures we are ready to accommodate the most extreme demands we may face. Nevertheless, we recognize it is unlikely all of the plans developers have in our service area will proceed as quickly as expected. Our capital budget reflects the level of growth we anticipate based on the overall rate of development in our service area in recent years, anticipated economic conditions and management judgment. Given the uncertainty of development in our area, our plans are updated regularly to ensure that they reflect the most current plans of developers.

All projects, except for the Development Contribution Project, are considered enhancements. The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, which is expected in 2012 and 2013, it is estimated Midland PUC will pay a transfer price of for the assets installed by the developer.

Midland PUC has a vehicle replacement plan for the replacement of its rolling stock. In addition, assessments are done on the vehicles each year to ensure that the plan is kept up to date. The strategic vehicle replacement program will replace aging vehicles in an even fashion avoiding sudden increases in capital acquisitions. Midland PUC's vehicle replacement process considers the following criteria:

Vehicle operational condition;
Vehicle safety;
Mileage; age; engine hours;
Department needs; and
Replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

The vehicle replacement program is based on annual condition surveys and life cycle planning. New vehicles and equipment support productivity through innovation, improve crew response time, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Each year Midland PUC looks at other plant, equipment and vehicles, along with the distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of Midland PUC's distribution system are made.

In 2010 and 2011, Midland PUC commissioned an Asset Management Study and Asset Condition Study to provide inspections and assessments of the distribution system to determine the age, condition and reliability of the distribution assets. Once this was accomplished, Midland PUC was able to develop a GIS database using Autodesk AutoCAD Maps 3D. This database is used in planning maintenance and capital projects as well as documentation and information management for IFRS applications.

CHANGES IN METHODOLOGY:

Midland PUC is not requesting any changes in methodology in the current proceeding.

REVENUE DEFICIENCY:

Midland PUC has provided detailed calculations supporting its 2013 revenue deficiency. Midland PUC's net revenue deficiency is $ 192,840 and when grossed up for PILs Midland PUC's revenue deficiency is $ 228,213 . Table 6.1.1 on the following page provides the revenue deficiency calculations for the 2013 Test Year at Existing 2012 Board-approved rates and the 2013 Test Year Revenue Requirement.

1

Table 6.1.1: Calculation of Revenue Deficiency (MIFRS)

Description	2012 Bridge Actual (MIFRS)	2013 Test (MIFRS) Existing Rates	2013 Test (MIFRS) - Required Revenue
Revenue			
Revenue Deficiency			**228,213**
Distribution Revenue	3,643,891	3,573,629	3,573,629
Other Operating Revenue (Net)	229,986	263,604	263,604
Total Revenue	**3,873,877**	**3,837,233**	**4,065,446**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,413,412	1,588,105	1,588,105
Operation & Maintenance	806,988	927,828	927,828
Depreciation & Amortization	626,027	682,735	682,735
Amortization on PP&E Adjustment		(58,866)	(58,866)
Return on PP&E Adjustment		(13,323)	(13,323)
Property Taxes	29,500	30,385	30,385
Deemed Interest	397,204	322,428	322,428
Total Costs and Expenses	**3,273,131**	**3,479,293**	**3,479,293**
Utility Income Before Income Taxes	**600,746**	**357,940**	**586,153**
Income Taxes:			
Corporate Income Taxes	5,212	(34,395)	978
Total Income Taxes	**5,212**	**(34,395)**	**978**
Utility Net Income	**595,535**	**392,335**	**585,175**
Income Tax Expense Calculation:			
Accounting Income	600,746	357,940	586,153
Tax Adjustments to Accounting Income	(567,122)	(579,843)	(579,843)
Taxable Income	**33,625**	**(221,903)**	**6,310**
Income Tax Expense	5,212	(34,395)	978
Tax Rate Refecting Tax Credits	15.5000%	15.5000%	15.50%
Actual Return on Rate Base:			
Rate Base	14,979,774	16,040,975	16,040,975
Interest Expense	397,204	322,428	322,428
Net Income	595,535	392,335	585,175
Total Actual Return on Rate Base	**992,738**	**714,763**	**907,603**
Actual Return on Rate Base	6.63%	4.46%	5.66%
Required Return on Rate Base:			
Rate Base	14,979,774	16,040,975	16,040,975
Return Rates:			
Return on Debt (Weighted)	4.42%	3.35%	3.35%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	397,204	322,428	322,428
Return On Equity	479,952	585,175	585,175
Total Return	**877,156**	**907,603**	**907,603**
Expected Return on Rate Base	5.86%	5.66%	5.66%
Revenue Deficiency After Tax	**(115,583)**	**192,840**	**0**
Revenue Deficiency Before Tax	**(136,784)**	**228,213**	**0**

CAUSES OF REVENUE DEFICIENCY:

Midland PUC's net revenue deficiency is calculated as $ 228,213. Midland PUC's calculation of its 2013 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4 and Exhibit 6, Tab 1, Schedule 1.

The revenue deficiency is primarily the result of:

- Capital Expenditures have exceeded depreciation levels resulting in an increased rate base on which the rate of return is calculated. Midland PUC is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure in 2012 and 2013 at a level exceeding depreciation. Changes in the Rate Base are discussed further in Exhibit 2.

- Increases in OM&A costs since Midland PUC's last cost of service in 2009. For the 2013 Test Year Midland PUC is forecasting OM&A expenses increasing at a compound annual growth rate of 5.5% per year since 2009 Board Approved. Midland PUC has provided a detailed explanation of changes in operating expenses in Exhibit 4.

- Increases in OM&A costs as a result of the Smart Meter Initiative are detailed under Exhibit 4.

- Labour and payroll OM&A have increased over 2009 Board Approved levels as detailed in Exhibit 4.

A summary of the increases in OM&A in 2013 over the 2009 COS Application are outlined in Table 1.2.2 below:

Table 1.2.2: Summary of OM&A Variance – 2009 COS vs. 2013 Test Year

Summary of Increases in 2009 COS vs. 2013 Test Year OM&A Expenses	
Smart Meter Expenses	$ 170,863.08
IFRS - Wages & Benefits	$ 39,029.50
2013 - 2 FTEE's	$ 171,300.00
Wage/Benefit Increases	$ 62,313.02
All Other Expenses	$ 7,277.50
Total Increase in 2013 over 2009 COS	**$ 450,783.09**

FINANCIAL STATEMENTS – 2009, 2010 and 2011:

Midland PUC's Audited Financial Statements accompany this Schedule as Appendix D.

APPENDIX D

COPIES OF MIDLAND POWER UTILITY CORPORATION AUDITED FINANCIAL STATEMENTS FOR 2009, 2010 and 2011

Midland Power Utility Corporation

Financial Statements
For the year ended December 31, 2009

Midland Power Utility Corporation
Financial Statements
For the year ended December 31, 2009

Contents

Auditors' Report

To the Shareholder of Midland Power Utility Corporation

We have audited the balance sheet of Midland Power Utility Corporation as at December 31, 2009 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

Except as explained in the following paragraph, we conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

Canadian generally accepted accounting principles require that a goodwill impairment loss be recognized when the carrying amount of the goodwill of a reporting unit exceeds the fair value of the goodwill. A valuation of the corporation is required in order to determine whether or not goodwill has been impaired. Management has decided that the valuation is not necessary at this time. As a result, we are unable to determine the adjustment, if any, to goodwill, expenses, net income and retained earnings as well as related disclosure that would be necessary to reflect the impairment, if any, of goodwill.

In our opinion, except for the effect of adjustments and related disclosure for goodwill impairment, if any, which we may have determined to be necessary had we been able to obtain sufficient information as described in the previous paragraph, these financial statements present fairly, in all material respects, the financial position of the corporation as at December 31, 2009 and the results of its operations and the changes in its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

Collingwood, Ontario

March 5, 2010

Midland Power Utility Corporation
Balance Sheet

December 31	2009	2008
Assets		(Note 23)
Current		
Cash and bank (Note 2)	$ 135,561	$ 281,959
Energy revenue accounts receivable	847,458	1,154,503
Other accounts receivable	76,266	112,706
Unbilled energy revenue	2,181,887	1,922,655
Due from shareholder (Note 3)	26,025	38,596
Inventory	62,007	85,251
Prepaid expenses	208,632	191,166
Payments in lieu of corporate taxes receivable	184,016	337,654
	3,721,852	4,124,490
Future income tax asset (Note 4)	621,649	-
Property, plant and equipment (Note 5)	9,548,050	7,951,693
Goodwill	1,260,000	1,260,000
Regulatory assets net of regulatory liabilities (Note 6)	223,857	-
Long-term investments (Note 7)	100	100
	$15,375,508	$ 13,336,283

	2009	2008
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 8)	$ 960,000	$ -
Accounts payable and accrued liabilities (Note 9)	3,615,565	2,969,666
Due to shareholder (Note 3)	2,531	30,196
Construction loan advances (Note 10)	1,422,519	-
Current portion of customer deposits	109,243	139,299
Construction deposits	17,186	55,116
	6,127,044	3,194,277
Customer and retailer deposits	219,302	208,718
Due to shareholder (Note 3)	-	1,122,519
Employee future benefits (Note 11)	78,065	125,390
Other long-term liabilities (Note 12)	-	29,181
Regulatory liabilities net of regulatory assets (Note 6)	-	416,834
Future income tax liability (Note 4)	179,908	-
	6,604,319	5,096,919
Contingencies (Note 13)		
Shareholder's equity		
Share capital (Note 14)	6,880,984	6,880,984
Retained earnings	1,890,205	1,358,380
	8,771,189	8,239,364
	$15,375,508	$ 13,336,283

On behalf of the Board:

____________________ Director ____________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Operations and Retained Earnings

For the year ended December 31	2009	2008
Energy revenue	$19,695,846	$ 18,998,229
Cost of power (Note 20)	16,591,122	16,290,687
Net distribution revenue	3,104,724	2,707,542
Net service revenue (Note 15)	43,618	39,978
Other net revenue (Note 16)	306,304	273,856
	3,454,646	3,021,376
Expenses		
Administration	796,513	746,037
Amortization	684,753	610,282
Billing and collecting	338,491	309,365
Interest	12,921	12,824
Interest on long-term debt	36,278	30,196
Operations	684,992	728,078
	2,553,948	2,436,782
	900,698	584,594
Provision for payments in lieu of corporate income taxes and capital tax (Note 4)	68,873	270,500
Net income for the year	831,825	314,094
Retained earnings, beginning of year	1,358,380	1,344,286
Dividends (Note 3)	300,000	300,000
Retained earnings, end of year	$ 1,890,205	$ 1,358,380

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Cash Flows

For the year ended December 31	2009	2008
Cash flows from operating activities		
Net income for the year	$ 831,825	$ 314,094
Amortization	684,753	610,282
	1,516,578	924,376
Changes in non-cash working capital:		
Energy revenue accounts receivable	307,045	(116,380)
Other accounts receivable	36,440	44,908
Unbilled energy revenue	(259,232)	147,460
Due from shareholder	(15,094)	(7,643)
Inventory	23,244	6,466
Prepaid expenses	(17,466)	(104,408)
Accounts payable and accrued liabilities	645,899	(200,566)
Payments in lieu of corporate taxes receivable/payable	153,638	(403,765)
Future income taxes net change	(441,741)	-
Construction deposits	(37,930)	(156,779)
Employee future benefits	(47,325)	(2,151)
	347,478	(792,858)
	1,864,056	131,518
Cash flows from investing activities		
Expenditures on property, plant and equipment	(2,281,110)	(1,740,069)
Net decrease in regulatory assets	(640,691)	435,132
	(2,921,801)	(1,304,937)
Cash flows from financing activities		
Repayment of amount due to shareholder	(1,122,519)	-
Customer and retailer deposits	(19,472)	(76)
Construction loan advances	1,422,519	-
Net decrease in other long-term liabilities	(29,181)	(23,703)
Dividends paid	(300,000)	(300,000)
	(48,653)	(323,779)
Decrease in cash during the year	(1,106,398)	(1,497,198)
Cash and bank, beginning of year	281,959	1,779,157
Cash (bank indebtedness), end of year	$ (824,439)	$ 281,959
Represented by		
Cash and bank	$ 135,561	$ 281,959
Bank indebtedness	(960,000)	-
	$ (824,439)	$ 281,959

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Nature of Business

The corporation was incorporated under the laws of the Province of Ontario on December 22, 1999 in accordance with the provincial government's Electricity Act, 1998. Subsequently, Midland Power Utility Corporation, Mid-Ontario Energy Services Inc. and Community One-Lan Solutions Inc. were amalgamated on May 1, 2002. The newly formed corporation operating as Midland Power Utility Corporation is licensed by the Ontario Energy Board ("OEB") as an electricity distributor. The principal activity of the corporation is to distribute electricity to the Town of Midland. The corporation is regulated by the OEB and adjustments to the distribution and power rates require OEB approval.

Basis of Accounting

The financial statements of Midland Power Utility Corporation are prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook"), issued under the authority of the Ontario Energy Board Act, 1998.

Due to the regulatory framework, the timing of recognition of revenues and expenses and the measurement of certain assets and liabilities may differ from that otherwise expected under Canadian generally accepted accounting principles (GAAP) for non-rate regulated enterprises. Please refer to accounting policies for Spare Transformers and Meters, Post 1999 Contributed Capital, Regulatory Assets and Liabilities, Payments in lieu of corporate income taxes and capital taxes and Ontario Price Credit Rebates.

The financial statements reflect the significant accounting policies summarized below.

Regulation and Rate Setting

The corporation is required to follow regulations as set by the OEB. The OEB approves and sets rates for the transmission and distribution of electricity, ensures distribution companies fulfill their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers.

The OEB sets rates on an annual basis with rates becoming effective on May 1st through April 30th of the following year. The regulation and monitoring of Ontario's Energy Sector is completed by the OEB through application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

Regulatory Assets and Liabilities	The corporation has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory assets or regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition. Regulatory assets represent future revenues associated with certain costs, incurred in current or prior period(s), that are expected to be recovered through the rate setting process. Regulatory liabilities represent future reductions or limitations of revenue increases associated with amounts that are expected to be refunded to customers. Regulatory assets and liabilities can arise from differences in amounts billed to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the corporation in the wholesale market administered by the Independent Electricity System Operator "IESO" after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act and deferred in anticipation of their future recovery in electricity distribution service charges. In the absence of regulation the regulatory assets and liabilities would be recognized in income in the period to which they relate.
Inventory	Inventory consists of parts and supplies valued at the lower of cost and net realizable value. Cost is generally determined on the first-in, first-out basis.
Seasonality of Operations	The corporation's operations are seasonal. Electricity consumption is typically highest in the summer and winter months, July through September and January through March.
Spare Transformers and Meters	Spare transformers and meters are held to back up plant in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired. According to the criteria prescribed by the OEB in the AP Handbook the spare transformers and meters are treated as capital assets and included in the distribution systems category. Under Canadian GAAP for unregulated businesses the spare transformers and meters would be treated as inventory.

Post 1999 Contributed Capital	Post 1999 contributed capital consists of third party contributions toward the cost of constructing distribution assets collected after January 1, 2000, and are recorded with property, plant and equipment as a contra account. Contributions are amortized at rates corresponding with the useful lives of the related property, plant and equipment. Canadian GAAP provides no specific guideline on the accounting treatment for this type of contribution. Post 1999 contributed capital is included in distribution system in the schedule of capital assets.
Long-term Investments	The corporation records its long-term investments using the cost method.
Goodwill	Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased. Goodwill is not amortized but is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that the asset might be impaired. Goodwill impairment is assessed based on a comparison for the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill. When the carrying amount of goodwill exceeds the implied fair value of goodwill an impairment loss is recognized in an amount equal to the excess as a charge against the results of operations. Management has decided that a valuation was not necessary and therefore impairment of goodwill could not be assessed.
Construction Deposits	Construction deposits represent maintenance deposits and deposits for recoverable work.
Customer Deposits	Customer deposits represent amounts collected from customers to guarantee the payment of energy bills. The customer deposits liability includes interest credited to customers' deposit accounts, with interest expense recorded to offset this amount. Deposits expected to be refunded to customers within one year are classified as a current liability. Customer deposits also include prudential deposits from retailers.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, engineering costs, and interest on funds used during construction when applicable. Also included in property, plant and equipment are the costs of capital assets constructed by developers or customers and contributed to the corporation.

Upon disposal the cost and accumulated amortization related to the asset are removed and any gains or losses on disposal are credited or charged to other income on the statement of operations.

Amortization is provided using the following method and annual rates:

Buildings	- 20 years	straight-line basis
Distribution system	- 25 years	straight-line basis
Supervisory equipment	- 15 years	straight-line basis
Rolling stock	- 5 - 8 years	straight-line basis
Shop, general office, and stores equipment	- 10 years	straight-line basis
Computer hardware and computer software	- 5 years	straight-line basis
Wireless equipment	- 10 years	straight-line basis

Spare and replacement parts included in property, plant and equipment are not amortized until they are put into service.

Construction in progress is included in property, plant and equipment and not amortized until the project is complete.

Pension Plan

The corporation offers a pension plan for its full-time employees through the Ontario Municipal Employee Retirement System ("OMERS"). OMERS is a multi-employer, contributory, public sector pension fund established for employees of municipalities, local boards and school boards in Ontario. Participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation accounts for its participation in OMERS as a defined contribution plan and recognizes the expense related to this plan as contributions are made.

Post-employment Benefits

Employee future benefits other than pension provided by the corporation include life insurance premiums paid by the corporation. This plan provides benefits to employees who retired prior to May 2002.

Standards issued by The Canadian Institute of Chartered Accountants with respect to accounting for employee future benefits require the corporation to accrue for its obligations under other employee benefit plans and related costs, net of plan assets.

The cost of post-employment benefits offered to retirees are actuarially determined using the projected benefit method and based on assumptions that reflect management's best estimate.

Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on the accrual basis. The revenue includes cycles billed during the year plus an estimate for unbilled revenue. The unbilled revenue is calculated by prorating the actual consumption of electricity by customers since their last meter reading date, based on meter readings subsequent to year end, for consumption to December 31, 2009. Actual results could differ from estimates made of electricity usage.

Other revenues, which include revenues from pole attachment, customer demand work, and other miscellaneous revenues are recognized at the time the service is provided.

Ontario Price Credit Rebates

Consumers other than designated consumers who annually utilize more than 250,000 kWh continue to be eligible to receive Ontario Price Credit Rebates ("OPC Rebates") from the IESO to the extent that electricity prices exceed certain prescribed thresholds.

The corporation and other electricity distributors are required to pass these rebates to eligible customers and other market participants (including retailers). The corporation includes amounts due to eligible customers and market participants in accounts payable and accrued liabilities.

These rebates are recognized as a reduction in the cost of power purchased. (See Note 20)

The Ontario price credit rebates ended effective January 31, 2009.

December 31, 2009

Use of Estimates and Measurement Uncertainty	The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date. Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered which reflect an appropriate allowance for unrecoverable amounts. Due to inherent uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance. The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the accounting policies.
Payment in Lieu (PIL) of Corporate Income Taxes and Capital Taxes	The corporation is a municipal electricity utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario). Each taxation year, the corporation is required to make payments in lieu of corporate income taxes and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated based on the rules for computing taxable income and taxable capital outlined in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) taking into account any modifications made by the Electricity Act, 1998, and related regulations. The corporation provides for payments in lieu of corporate income taxes and capital taxes related to its regulated business using the liability method of accounting. Until December 31, 2008 the taxes payable method was applied as permitted by the CICA and OEB. Effective January 1, 2009 the corporation began using the liability method of accounting following the new recommendations from the CICA and OEB.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to regulatory assets and liabilities. The net balance represents future income taxes that flow through the rate-making process.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

Financial Instruments

All financial instruments are included on the balance sheet and are measured either at fair market value or, in limited circumstances, at cost or amortized cost.

The fair values of cash and bank, accounts receivable, unbilled revenue, current customer deposits, accounts payable and accrued liabilities, bank indebtedness and construction loan advances approximate their carrying amounts because of the short-term maturity of these instruments.

The corporation classifies its financial instruments into one of the following categories:

Continued...

Financial Instruments **continued**

Held-for-trading

Held-for-trading is comprised of cash and bank. This instrument is carried in the balance sheet at fair value with changes in fair value recognized in the income statement. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Loans and receivables

Loans and receivables are comprised of accounts receivable and unbilled revenue. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest rate method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other financial liabilities

Other financial liabilities are comprised of bank indebtedness, accounts payable and accrued liabilities, customer and construction deposits, amounts due to shareholder, and construction loan advances. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are netted against the amount initially recognized.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International Financial Reporting Standards

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP prior to 2011, with the remaining standards to be adopted at the change over date. The corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. Although the impact of the adoption of IFRS on the corporation's financial position and results of operations is not yet reasonably determinable or estimable, the corporation does expect a significant increase in financial statement disclosure requirements resulting from the adoption of IFRS, and is designing the systems and related changes to processes, which will be required in order to provide the additional information required to make these disclosures.

1. Changes in Accounting Policies

Rate Regulated Entities

Effective January 1, 2009, the corporation adopted amended Canadian Institute of Chartered Accountants ["CICA"] Handbook Sections 1100 – "Generally Accepted Accounting Principles", 3465 – "Income Taxes", and Accounting Guideline 19 – "Disclosures by Entities Subject to Rate Regulation" ["AcG-19"]. These amended standards remove a temporary exemption in CICA Handbook Section 1100 pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate regulation.

The new standards require the recognition of future income tax liabilities and assets in accordance with CICA Handbook Section 3465 as well as a separate regulatory asset or liability balance for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers, and retain existing requirements to disclose the effects of rate regulation. The revised standards are effective for interim and annual financial statements for the fiscal years beginning on or after January 1, 2009.

Following the removal of the temporary exemption for rate-regulated operations included in Section 1100, the corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgment and other sources issued by bodies authorized to issue accounting standards in other jurisdictions. Upon final assessment and in accordance with Section 1100, the corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP and this recognition is consistent with U.S. Statement of Financial Accounting Standards No. 71 – "Accounting for the Effects of Certain Types of Regulation". Accordingly, the removal of the temporary exemption had no effect on the corporation's results of operations as of December 31, 2009.

The impact of the amendment to Section 3465 requires the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates, applied on a retrospective basis without prior period restatement. The implementation of these standards did not impact the corporation's earnings or cash flows. As at December 31, 2009, the corporation has recorded a future income tax asset of $621,649, a future income tax liability of $179,908 and a corresponding net regulatory liability $441,741 (See Notes 4 & 6).

1. Changes in Accounting Policies continued

Goodwill

Effective January 1, 2009, the corporation retrospectively adopted CICA Handbook Section 3064 - “Goodwill and Intangible Assets”. Handbook Section 3064 replaces Handbook Section 3062 and provides extensive guidance on recognition, measurement and disclosure of intangible assets.

The corporation evaluated existing intangible assets as at January 1, 2009 to determine whether the intangible assets recognized under previous Handbook Section 3062 met the definition, recognition, and measurement criteria of an intangible asset in accordance with Handbook Section 3064. The corporation did not identify any expenditures that no longer met the definition of intangible assets under Handbook Section 3064. As a result, there was no impact on the financial statements from this change.

Credit Risk and Fair Value of Financial Assets and Financial Liabilities

In January 2009, the CICA issued Emerging Issues Committee Abstract 173, “Credit Risk and the Fair Value of Financial Assets and Financial Liabilities” [“EIC-173”], effective for interim and annual financial statements ending on or after January 2009. EIC-173 provides further information on the determination of the fair value of financial assets and financial liabilities under Handbook Section 3855, “Financial Instruments - Recognition and Measurement.” It states that an entity's own credit and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of this standard did not have any impact on the corporation’s results of operations or financial position.

Financial Statement Concepts

Effective January 1, 2009, the corporation adopted the new recommendations of the CICA Handbook Section 1000, Financial Statement Concepts, which has been amended to clarify the criteria for recognition of an asset. The amendments reinforce the distinction between costs that should be expensed and those that should be capitalized. The adoption of this new accounting standard did not impact the organization's financial statements.

2. Cash and Bank

The corporation's bank accounts are held at one chartered bank. The bank account earns interest at a variable rate.

3. Related Party Transactions

The following summarizes the corporation's related party transactions for the year with its shareholder, the Corporation of the Town of Midland:

	2009	2008
Revenue		
- Electricity charges	$ 579,199	$ 531,319
- Maintenance of streetlighting and other services	76,477	99,665
Expenses		
- Municipal taxes	41,968	44,119
- Lease fees for substation properties	49,980	49,980
- After hours answering service	20,000	20,000
- Communications antenna	20,000	20,000
- Vehicle servicing, job recoveries and miscellaneous	15,315	10,106
- Interest expense on promissory note payable	36,278	30,196
Dividends paid	300,000	300,000

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product or provision of service.

At the end of the year, the amounts due from and (to) its shareholder, the Corporation of the Town of Midland, are as follows:

	2009	2008
Trade receivable, unsecured, due on demand	$ 26,025	$ 38,596
Trade payable, unsecured, due on demand	$ (2,531)	$ -
Interest payable, unsecured, due Jan 30, 2009	$ -	$ (30,196)
Promissory note payable - 3.38% (2008 - 2.69%) based on the Government of Canada 10 year bond rate at December 11, 2009 (2008 - December 31, 2008), rate updated annually, unsecured with no specific terms of repayment	$ -	$ (1,122,519)

Continued...

3. Related Party Transactions continued

On December 15, 2009 the corporation repaid the promissory note payable to the Town of Midland.

The board of directors approved a $300,000 dividend to be paid to the Town of Midland in each of the 2009 and 2010 years.

The board of directors of Midland Power Utility Corporation received compensation and were reimbursed for certain administrative costs for the year in the amount of $27,591 (2008 - $28,436). These transactions were in the normal course of operations and were measured at the exchange amount.

The corporation paid $20,325 (2008 - $6,700) in fees to Cornerstone Hydro Electric Concepts Association Inc. (CHEC) (See Note 7).

The corporation paid $49,484 (2008 - $50,228) in fees to Utility Collaborative Services Inc. (UCS) for items such as information technology hosting and software licensing (See Note 7).

4. Payments in Lieu of Corporate Income Taxes and Future Income Taxes

(a) Payments in lieu of corporate income taxes (PILs)

The corporation's provision for PILs is calculated as follows:

	2009	2008
Income before provision for PILs	$ 900,698	$ 584,594
Statutory Canadian federal and provincial tax rate	33.00%	33.50%
Provision for PILs at statutory rate	297,230	195,839
Small business deduction	(69,219)	(56,383)
Cumulative eligible capital deduction	(22,457)	(684)
Net (increase) decrease in regulatory assets	(84,992)	145,769
Amortization expense in excess of capital cost allowance	(25,661)	(14,132)
Change in Pension Post retirement plan (not taxable)	(15,617)	(721)
Other items	(4,298)	-
Corporate minimum tax	11,994	-
Adjustment to tax provision	(18,107)	812
Total provision	$ 68,873	$ 270,500
Effective tax rate	7.65%	46.27%

Continued...

December 31, 2009

4. Payments in Lieu of Corporate Income Taxes, Capital Taxes, and Future Income Taxes Continued

(b) Future Taxes

On January 1, 2009, the corporation began to account for the differences between its financial statement carrying value and tax basis of its assets and liabilities following the liability method in accordance with CICA Handbook Section 3465 (See Note 1).

Prior to this change, rate regulated enterprises were not required to recognize future income taxes if they were expected to be included in the approved rates charged to customers and were expected to be recovered in the future. The change in accounting policy is applied on a retrospective basis without prior period restatement, therefore, the 2008 balances have not been reflected in the financial statements.

Significant components of the corporation's future tax assets (liabilities) are as follows:

	2009	2008 (Note)
Employee future benefits	$ 19,516	$ 36,363
Property, plant and equipment	602,133	418,017
Regulatory liabilities net of assets	-	120,882
Goodwill and land rights	-	4,065
Long-term future income tax asset	$ 621,649	$ 579,327
Goodwill and land rights	$ (13,508)	$ -
Regulatory liabilities net of assets	(166,400)	-
Long-term future income tax liability	$ (179,908)	$ -
Net future income tax asset	$ 441,741	$ 579,327

The offsetting entry to this net future income tax asset is a credit to regulatory liabilities (See Note 6).

Note: The 2008 figures above are for comparison purposes only, although not reflected in the financial statements.

December 31, 2009

5. Property, Plant and Equipment

	2009		2008	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Land	$ 381,738	$ -	$ 365,298	$ -
Land rights	32,555	15,060	32,555	15,060
Buildings	966,206	380,049	942,341	349,199
Distribution system	14,636,882	8,333,143	13,890,728	7,817,317
Supervisory equipment	357,012	248,799	357,012	226,695
Rolling stock	1,047,274	418,871	847,466	509,363
Shop equipment	344,080	268,477	326,927	257,092
General office equipment	251,230	222,236	249,144	215,420
Stores equipment	8,610	8,610	8,610	8,487
Computer equipment and software	736,096	581,554	681,349	522,381
Wireless equipment	69,891	69,891	69,891	69,891
Spare and replacement parts		190,639	-	171,277
-				
Construction in progress	1,072,527	-	-	-
	$20,094,740	$10,546,690	$ 17,942,598	$ 9,990,905
Net book value		$ 9,548,050		$ 7,951,693

During the year the corporation purchased property, plant and equipment totalling $1,981,110 (2008 - $1,740,069) using cash and $300,000 (2008 - $NIL) using financing.

The net book value of stranded meters related to the deployment of smart meters is included in property, plant and equipment in the distribution system category. In the absence of rate regulation, property, plant and equipment would have been decreased to remove the net book value of these stranded meters. The total net book value of all meters included in property, plant and equipment as at December 31, 2009 is $414,416. The decrease required in the absence of rate regulation is undeterminable as the components of the remaining net book value are not readily determinable.

6. Regulatory Assets and Liabilities

	2009	2008
Net regulatory assets (liabilities) consist of:		
Smart meter initiatives	$ 801,267	$ (17,849)
Deferral account for cash pension contributions	-	63,744
Deferral account for OEB annual cost assessments	-	14,041
Other regulatory assets - Hydro One incremental costs	3,661	-
Other regulatory assets - IFRS transition costs	7,150	-
Settlement variances	60,614	(467,901)
Carrying charges calculated using OEB specified rate	45,716	54,184
Regulatory asset balances as at December 31, 2004, plus accrued interest up to April 30, 2006 net of any recovery up to April 30, 2006 (see additional information below)	1,008,899	1,009,299
Recovery of regulatory assets beginning May 1, 2006	(1,072,352)	(1,072,352)
Disposition of account balances 2005 - 2007	(261,109)	-
Recovery of regulatory balances 2005 - 2007	71,752	-
Net future income tax liability	(441,741)	-
	$ 223,857	$ (416,834)

(i) Smart Meter Initiatives

The smart meter regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario by 2010. During 2006 the OEB developed recommendations on smart meters with regard to cost recovery during the phase-in period of this equipment. The OEB stated that given the increased need for electricity and the importance of conservation, specific funding for smart meters could be included in the 2006 rates for all Local Distribution Companies (LDCs). Variance accounts were established to track revenues collected with respect to smart meters and associated costs of the initiatives. The corporation completed the majority of the installation of all smart meters within its service territory in the 2009 year. The OEB approved the request to add a rate rider of $1.00 per customer per month to fund Smart Meter activities.

In connection with its smart meter initiatives, the corporation has incurred costs in 2009 amounting to $866,695 (2008 - $16,988). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In absence of rate regulation, revenues would have been higher in 2009 by $47,579 (2008 - $21,405) and amortization would have been higher in 2009 by $22,674 (2008 - $Nil).

(ii) Deferral account for cash pension contributions

The OEB has allowed the corporation to defer the incremental OMERS pension expenditures for fiscal years beginning after January 1, 2005 up to April 30, 2006. Accordingly, the corporation has deferred these expenditures in accordance with criteria set out in the AP Handbook. Under such regulation, expenditures are allowed to be deferred which would be expensed under Canadian GAAP for unregulated businesses. The deferred balance continued to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2009 would have been $NIL higher (2008 - $NIL higher). The OEB approved the corporation's proposal to clear this deferral account for disposition during the year.

Continued...

6. Regulatory Assets and Liabilities continued

(iii) Deferral account for OEB annual cost assessments

The OEB has allowed the corporation to record the variance between the OEB annual cost assessment fees previously captured in the 2001 rates and the amounts charged for fiscal years beginning after January 1, 2004 up to April 30, 2006. Accordingly, the corporation deferred these expenditures in accordance with the criteria set out in the AP Handbook. Under such regulation, expenditures are allowed to be deferred which would be expensed under Canadian GAAP for unregulated businesses. The deferred balance continued to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2009 would have been $NIL higher (2008 - $NIL higher). The OEB approved the corporation's proposal to clear this deferral account for disposition during the year.

(iv) Other Regulatory Assets - Hydro One Incremental Costs

The OEB has approved Other Regulatory Assets, "Sub-account Incremental Capital Charges", for distributors to record the charges arising from the capital rate relief rider. Interest carrying charges, calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates, are applicable for amounts recorded. The new incremental capital charge arises from an incremental capital module approved for Hydro One, which was effective on May 1, 2009 but was implemented on June 1, 2009.

(v) Other Regulatory Assets - IFRS transition costs

The OEB has approved the collection of $25,000 from customers per year over the next four years to cover the expected one-time costs of implementing International Financial Reporting Standards (IFRS). Expenses incurred are also included in this variance account and must be approved by the OEB. In the absence of rate regulation, expenses in 2009 would have been $7,150 higher (2008 - $Nil). The deferred balance continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance account has not yet been determined by the OEB.

(vi) Settlement Variances

Settlement variances represent the differences between amounts charged by the corporation to its customers based on regulated rates and the corresponding cost incurred by the corporation in the wholesale market administered by the IESO. Under the OEB's direction, the corporation has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the corporation has deferred these recoveries in accordance with the AP Handbook.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2009 would have been $304,359 lower (2008 - $129,007 higher). The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance has not been determined by the OEB.

Continued...

6. Regulatory Assets and Liabilities continued

(vii) Carrying Charges

Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. In the absence of rate regulation, other revenues would have been lower by $8,868 (2008 - $17,353 lower).

(viii) Recovery of Regulatory Assets

In a letter dated December 19, 2003, the Minister of Energy granted approval for distributors to make application to the OEB with regard to rate recovery of certain distribution regulatory assets whose inclusion in rates was delayed by the Electricity Pricing, Conservation and Supply Act, 2002 (Electric Pricing, Conservation and Supply Act). As a result of the corporation's distribution rate application dated January 22, 2004, the distribution regulatory assets that accumulated up to December 31, 2002 were recovered over a four-year period, effective March 1, 2004 with an implementation date for consumption of April 1, 2004. These amounts are now fully recovered.

The rate application for 2006, approved by the OEB, included the recovery of regulatory assets accumulated to December 31, 2004 plus projected interest on these balances up to April 30, 2006. This second phase of recovery was for a two year period with rates effective May 1, 2006. These amounts are now fully recovered.

The rate application for 2009, approved by the OEB, included the repayment of regulatory assets accumulated from January 1, 2005 - December 31, 2007 plus projected interest up to April 30, 2009. This phase of repayment is for a two year period with rates effective May 1, 2009.

(ix) Future Income Tax Regulatory Liability

This regulatory liability account relates to the expected future electricity distribution rate adjustments for customers arising from timing differences in the recognition of future taxes.

On January 1, 2009, the corporation began to account for the differences between its financial statement carrying value and tax basis of assets and liabilities following the liability method in accordance with CICA Handbook Section 3465 (See Notes 1 & 4).

(x) Fair Value of Regulatory Assets and Regulatory Liabilities

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the regulator in determining the asset's treatment for rate setting purposes. Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

7. Long-term Investments

	2009	2008
Cornerstone Hydro Electric Concepts Association Inc. (CHEC), incorporated without share capital. The cost for the investment was $Nil and therefore not included in these financial statements	$ -	$ -
Utility Collaborative Services Inc. (UCS), recorded using the cost method, 1 common share, 12.50% interest (2008 - 14.29% interest)	100	100
	$ 100	$ 100

Cornerstone Hydro Electric Concepts Association Inc. (CHEC) is an association of twelve electricity distribution utilities modelled after a cooperative to share resources and proficiencies.

Utility Collaborative Services Inc. (UCS) offers standards-based back office services. The collaboration allows leverage in the reduction of costs for items such as information technology hosting and software licensing.

8. Bank Indebtedness

	2009	2008
Bank overdraft	$ 960,000	$ -

The corporation has a line of credit with an authorized limit of $4,500,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances is calculated using the bank's prime rate, calculated and payable monthly. It is secured by a general security agreement covering all assets except real property.

As at December 31, 2009 the corporation had drawn a balance of $960,000 on this credit facility. The corporation's line of credit has been pledged as security for the letter of credit provided to the Independent Electricity Systems Operation ("IESO") (see Note 13). As a result, the corporation's access to the $4,500,000 credit facility mentioned above is limited to $2,444,270.

The agreement governing the line of credit facilities contains certain covenants as described in Note 21.

9. Accounts Payable and Accrued Liabilities

	2009	2008
IESO accounts payable	$ 1,268,007	$ 1,293,516
Trade accounts payable	1,217,835	707,290
Accrued liabilities	657,640	461,437
Customer credit balances	442,295	331,952
Deferred charges	607	65,815
Hydro One low voltage charges (See Note 12)	29,181	109,656
	$ 3,615,565	$ 2,969,666

10. Construction Loan Advances

	2009	2008
Infrastructure Ontario Construction Loan Advance - .95% floating rate, construction loan rates float throughout the term of the loan until they are replaced by a debenture, $56,126 principal repayable semi-annually plus interest, secured by a general security agreement covering a second charge on all assets and real property, due on demand	$ 1,122,519	$ -
Infrastructure Ontario Construction Loan Advance - .95% floating rate, construction loan rates float throughout the term of the loan until they are replaced by a debenture, $30,000 principal repayable semi-annually plus interest, secured by a general security agreement covering a second charge on all assets and real property, due on demand	300,000	-
	1,422,519	-
Current portion of long-term debt	1,422,519	
	$ -	$ -

Total construction advances of $5.5 million have been approved by Infrastructure Ontario. At December 31, 2009, the corporation had undrawn credit capacity under this facility of approximately $4,077,481. On February 16, 2010 another advance in the amount of $1,600,000 was received by the corporation. Subsequent to year-end the majority of the advances were converted to debentures. The $1,122,519 advance was used to repay the Town of Midland related party promissory note payable as reflected in Note 3. The $300,000 advance was used to purchase a new bucket truck.

The agreement governing these credit facilities contains certain covenants as described in Note 21.

11. Employee Future Benefits

During 2003 the corporation discontinued its post-retirement life insurance, dental and health benefits to all employees. As at December 31, 2009, there are only six (2008 - six) retirees who retain the post-retirement life insurance benefit.

Information about the post-retirement life insurance benefit plan is as follows:

	2009	2008
Accrued benefit liability, beginning of year	$ 125,390	$ 127,541
Expense for the year	(2,927)	(2,151)
Change in post-retirement plan - (d) below	(44,398)	-
Projected accrued benefit obligation at December 31	$ 78,065	$ 125,390

An actuarial report was performed and dated January 20, 2010. The actuarial valuation was performed on the post-retirement obligations sponsored by Midland Power Utility Corporation as at December 31, 2009. The next actuarial valuation should be performed by December 31, 2012.

The main actuarial assumptions employed for the valuations are as follows:

(a) General inflation
Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% per annum.

(b) Interest (discount) rate
The obligation, as at December 31, 2009, of the present value of future liabilities was determined using an annual discount rate of 6.0%. This rate reflects the assumed long-term yield on high quality bonds.

(c) Expenses
The assumption was made that 10% of benefits are required for the cost of sponsoring the program for life insurance.

(d) Change in Post-Retirement Plan
The accrued benefit obligation was decreased in 2009 over the 2006 valuation mainly as a result of a higher discount rate assumption and the death of one retiree.

12. Other Long-Term Liabilities

	2009	2008
Hydro One Low Voltage Charges	$ -	$ 29,181

The above amount represents the long-term portion of amounts owing to Hydro One for low voltage charges. The total amount owing is $29,181, of which $29,181 (2008 - $109,656) has been included in accounts payable and accrued liabilities as it is due to be repaid within one year.

13. Contingencies

i) Griffith et al. v. Toronto Hydro-Electric Commission et al.
This action has been brought under the Class Proceedings Act, 1992. The plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities (“LDCs”) who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. The parties are in settlement discussions but no settlement has been reached. At this time, it is not possible to quantify the effect, if any, on the financial statements.

The corporation collected total late payment penalties of approximately $653,000 from April 30, 1994 to May 1, 2001. No determination of the portion of these payments which may have constituted interest at an impermissible rate has been made, and as such, no accrual for any potential liability has been recorded in the financial statements.

On February 10, 2009, the Superior Court of Justice approved the settlement agreement related to the Class action proceeding on late payment penalties against Union Gas. Decisions and/or settlements from Enbridge and Union Gas cases may have precedent-setting implications for the outcome of this case.

(ii) The corporation is contingently liable as a guarantor for a letter of credit for $1,095,730 with its bank provided to the Independent Electricity Systems Operator (IESO) to secure the corporation's hydro purchase obligations.

14. Share Capital

The authorized share capital of the corporation is an unlimited number of common and preference shares. The issued share capital is as follows:

		2009	2008
1,000	Common shares	$ 6,880,984	$ 6,880,984

15. Net Service Revenue

	2009	2008
Service revenue	$ 102,751	$ 102,905
Service costs	(59,133)	(62,927)
Net service revenue	$ 43,618	$ 39,978

16. Other Net Revenue

	2009	2008
Carrying charges on regulatory balances	$ (8,868)	$ (17,353)
Gain on disposal	13,025	1,670
Interest earned	37,483	36,787
Late payment charges	20,871	19,409
Other	107,033	108,873
Ontario Power Authority management fees	46,594	31,593
Office rental	53,148	55,902
Pole rental	37,018	36,975
	$ 306,304	$ 273,856

17. Statement of Cash Flows

	2009	2008
Interest paid	$ 49,199	$ 43,020
Interest received	$ 37,483	$ 36,787
PILs paid	$ 270,996	$ 700,030
PILs received	$ 361,497	$ 25,765

December 31, 2009

18. Liability Insurance

The corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members.

The corporation is named as a defendant in an action commenced on July 31, 2009 in the Ontario Superior Court of Justice. The claim is for $350,000 in damages plus interest and legal costs and is as a result of a fire that the Plaintiff is claiming was caused by an electrical failure as a result of the negligence of Midland Power Utility Corporation. The corporation is denying any liability and has passed this action along to their insurer, Mearie. If held liable, the corporation will be required to pay the deductible of $1,000.

19. Pension Agreements

The corporation makes contributions to the Ontario Municipal Employee Retirement System (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to more than 390,000 active and retired members and approximately 921 employers. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2008. The results of this valuation disclosed total actuarial liabilities of $50,080 (2007 - $46,830) million in respect of benefits accrued for service with actuarial assets at that date of $49,801 (2007 - $46,912) million, indicating an actuarial deficit of $279 million at the end of 2008, compared with a funding surplus of $82 million in the prior year. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the corporation does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for the plan were 6.3% (2008 - 6.5%) for employees earning up to $46,300 (2008 - 44,900) and 9.5% thereafter. The amount contributed to OMERS for 2009 was $120,379 (2008 - $129,342).

20. Ontario Price Credit Rebates

During the year ended December 31, 2009 the corporation received OPC Rebates pertaining to consumption for the period from August 1, 2008 to January 31, 2009. These rebates totalling $108,500 (2008 - $295,210 for the period from August 1, 2007 to July 31, 2008) were recognized as a reduction in the cost of power purchased.

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21. Capital Disclosures

The corporation considers its capital to be its long-term balance due to shareholder and shareholder's equity. The corporation's main objectives when managing capital are to: i) ensure sufficient liquidity to support its financial obligations and execute its operating and strategic plans, ii) minimize the cost of capital while taking into consideration current and future industry, market and economic risks and conditions, iii) maintain an optimal capital structure that provides necessary financial flexibility while also ensuring compliance with any financial covenants, and iv) provide an adequate return to its shareholder.

The corporation relies predominately on its cash flow from operations to fund its dividend distributions to its shareholder. This cash flow is supplemented, when necessary, through the borrowing of additional debt.

As part of existing debt agreements, financial covenants are monitored and communicated, as required by the terms of credit agreements, on an annual basis by management to ensure compliance with the agreements.

The bank indebtedness covenants require the corporation to maintain a minimum Interest Coverage Ratio of 2.5 times and to maintain a maximum Total Debt to Capitalization of 0.60:1. The corporation was in compliance with these covenants as at December 31, 2009.

The Infrastructure Ontario loan covenants require the corporation to provide notification prior to any new debt issuance and to seek approval where the Debt Service Coverage Ratio falls below 1 to 1 at any time; such ratio is otherwise tested and calculated as of the end of each fiscal year. The corporation is also required to maintain a maximum Debt to Capital ratio of 0.60 to 1 and a minimum current ratio of 1.1 to 1 to be tested and calculated as of the end of each fiscal year. The corporation is still in the construction phase of this loan and advances are not yet fully complete. The Infrastructure Ontario loan advances have been reflected as current as they have not been converted to termed debentures as at December 31, 2009. The corporation is in compliance with these covenants as at December 31, 2009, except for the current ratio, however, compliance is not required until the debentures are in place.

Management monitors certain key ratios to effectively manage capital. The OEB provides a guideline for the optimal debt to equity structure being 60/40 based on the OEB's classification of debt. As at December 31, 2009 the corporation had a debt to equity structure based on this formula of 14/86 (2008 - 12/88).

22. Financial Risk Management

As part of its operations, the corporation carries out transactions that expose it to financial risks such as credit, liquidity and market risks.

The following is a discussion of risks and related mitigation strategies that have been identified by the company for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

Credit risk

Credit risk is the risk that one party to a financial instrument might not meet its obligations under the terms of the financial instrument. The maximum credit exposure is limited to the carrying amount of cash and receivables presented on the balance sheet.

Financial instruments that potentially subject the corporation to a significant concentration of credit risk consist primarily of cash. The corporation limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The corporation maintains cash with one major financial institution. Eligible deposits are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The corporation is exposed to credit risk related to accounts receivable arising from its day-to-day electricity and service revenue. Exposure to credit risk from accounts receivable is limited due to the corporation's large and diverse customer base. Moreover, the corporation holds as collateral customer, retailer and construction deposits, which are recognized as liabilities on the balance sheet. The Ontario Energy Board has prescribed certain rules for the payment of deposits by customers. Although these rules limit the risk of the company, no deposits are required by customers who have shown good payment history for the previous 24 month period. The company does not have any material accounts receivable balances greater than 90 days outstanding. As a result, the company believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the income statement. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

The company’s accounts receivable are not subject to a significant concentration of credit risk because they are distributed over a large customer base.

The value of accounts receivable, by age, and the related bad debt provision are presented in the following table. The accounts receivable balance consists of energy, other and unbilled revenue receivables.

Unbilled revenue represents amounts to which the corporation has a contractual right to receive cash through future billings but are unbilled at period-end. Unbilled revenue outstanding is considered current.

Continued...

22. Financial Risk Management continued

Accounts Receivable

	2009	2008
Under 30 days	$ 3,177,613	$ 3,199,316
30 to 60 days	16,507	21,304
61 to 90 days	4,774	14,166
Over 90 days	39,560	35,078
	3,238,454	3,269,864
Provision	132,843	80,000
Total accounts receivable	$ 3,105,611	$ 3,189,864
Represented by:		
Energy revenue accounts receivable	$ 847,458	$ 1,154,503
Other accounts receivable	76,266	112,706
Unbilled energy revenue	2,181,887	1,922,655
	$ 3,105,611	$ 3,189,864

Liquidity risk

Liquidity risk is the risk that the corporation will encounter difficulty in meeting obligations associated with financial liabilities. The corporation’s approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation’s reputation. The corporation's exposure is reduced by cash generated from operations and their undrawn credit facility. The corporation engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting.

Liquidity risks associated with financial commitments are as follows:

	0 - 3 mo	3 mo - 1 yr	1 - 5 yr	Termless
Bank indebtedness	$ 960,000	$ -	$ -	$ -
Accounts payable and accrued liabilities	3,615,565	-	-	-
Construction loan	1,422,519	-	-	-
Due to shareholder	2,531	-	-	-
Customer deposits	-	109,243	219,302	-
Construction deposits	-	17,186	-	-
Employee future benefits	-	2,927	11,708	63,430
Total	$ 6,000,615	$ 129,356	$ 231,010	$ 63,430

Continued...

22. Financial Risk Management continued

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the corporation's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The corporation does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The corporation had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2009.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The corporation is exposed to interest rate fluctuations on its cash and bank, undrawn credit facilities and promissory note due to shareholder which bear a floating rate of interest. The corporation's exposure to interest rate risk is limited by cash from operations making it possible to maintain a high interest coverage ratio. As at December 31, 2009, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

23. Comparative Figures

Certain comparative figures have been reclassified to conform with the current period's financial statement presentation.

The balance sheet reflects a prior period adjustment to reverse an invoice that was determined not to be payable based on information that became available subsequent to year-end. $233,000 has been reversed from accounts payable and property, plant and equipment for the 2008 year-end. There was no material impact on income.

Midland Power Utility Corporation

Financial Statements

For the year ended December 31, 2010

Midland Power Utility Corporation
Financial Statements
For the year ended December 31, 2010

Contents

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BDO Canada LLP
186 Hurontario Street, Suite 202
Collingwood ON L9Y 4T4 Canada

Independent Auditor's Report

To the Shareholder of Midland Power Utility Corporation

We have audited the accompanying financial statements of Midland Power Utility Corporation, which comprise the balance sheet as at December 31, 2010, the statements of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

Canadian generally accepted accounting principles require that a goodwill impairment loss be recognized when the carrying amount of the goodwill of a reporting unit exceeds the fair value of the goodwill. A valuation of the corporation is required in order to determine whether or not goodwill has been impaired. Management has decided that the valuation is not necessary at this time. As a result, we are unable to determine the adjustment, if any, to goodwill, expenses, net income and retained earnings as well as related disclosure that would be necessary to reflect the impairment, if any, of goodwill.

Qualified Opinion

In our opinion, except for the effects of the matter described in the Basis for Qualified Opinion paragraph, the financial statements present fairly, in all material respects, the financial position of Midland Power Utility Corporation as at December 31, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Collingwood, Ontario
March 11, 2011

Midland Power Utility Corporation
Balance Sheet

December 31	2010	2009
Assets		
Current		
Cash and bank (Note 1)	$ 177,301	$ 135,561
Energy revenue accounts receivable	1,168,187	847,458
Other accounts receivable (Note 2)	311,437	76,266
Unbilled energy revenue	2,094,265	2,181,887
Due from shareholder (Note 3)	81,316	26,025
Inventory	46,043	62,007
Prepaid expenses	200,624	208,632
Payments in lieu of corporate taxes receivable	189,772	184,016
	4,268,945	3,721,852
Future income tax asset (Note 5)	566,645	621,649
Property, plant and equipment (Note 6)	10,872,977	9,548,050
Goodwill	1,260,000	1,260,000
Regulatory assets net of regulatory liabilities (Note 7)	452,555	223,857
Long-term investments (Note 8)	100	100
	$ 17,421,222	$ 15,375,508

	2010	2009
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 9)	$ 760,000	$ 960,000
Accounts payable and accrued liabilities (Note 10)	3,297,885	3,615,565
Due to shareholder (Note 3)	5,352	2,531
Deferred revenue	43,609	-
Current portion of customer deposits	149,868	109,243
Construction deposits	17,186	17,186
Current portion of long-term debt (Note 11)	1,195,752	1,422,519
	5,469,652	6,127,044
Customer and retailer deposits	198,477	219,302
Long-term debt (Note 11)	2,213,891	-
Employee future benefits (Note 12)	74,625	78,065
Future income tax liability (Note 5)	188,792	179,908
	8,145,437	6,604,319
Contingencies (Note 13)		
Shareholder's equity		
Share capital (Note 14)	6,880,984	6,880,984
Retained earnings	2,394,801	1,890,205
	9,275,785	8,771,189
	$ 17,421,222	$ 15,375,508

On behalf of the Board:

__________________ Director __________________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Operations and Retained Earnings

For the year ended December 31	2010	2009
Energy revenue	**$21,529,959**	$ 19,695,846
Cost of power (Note 21)	**18,173,779**	16,591,122
Net distribution revenue	**3,356,180**	3,104,724
Net service revenue (Note 16)	**35,179**	43,618
Other net revenue (Note 17)	**250,246**	306,304
	3,641,605	3,454,646
Expenses		
Administration	**877,919**	796,513
Amortization	**773,443**	684,753
Billing and collecting	**330,322**	338,491
Interest	**9,595**	12,921
Interest on long-term debt	**89,843**	36,278
Operations	**670,080**	684,992
	2,751,202	2,553,948
Income before provision for payments in lieu of corporate income taxes and capital tax	**890,403**	900,698
Provision for payments in lieu of corporate income taxes and capital tax (Note 4)	**85,807**	68,873
Net income for the year	**804,596**	831,825
Retained earnings, beginning of year	**1,890,205**	1,358,380
Dividends (Note 3)	**300,000**	300,000
Retained earnings, end of year	**$ 2,394,801**	$ 1,890,205

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Cash Flows

For the year ended December 31	2010	2009
Cash flows from operating activities		
Net income for the year	$ 804,596	$ 831,825
Items not affecting cash:		
Amortization	773,443	684,753
	1,578,039	1,516,578
Changes in non-cash working capital:		
Energy revenue accounts receivable	(320,729)	307,045
Other accounts receivable	(235,171)	36,440
Unbilled energy revenue	87,622	(259,232)
Due to/from shareholder	(52,470)	(15,094)
Inventory	15,964	23,244
Prepaid expenses	8,008	(17,466)
Accounts payable and accrued liabilities	(317,680)	645,899
Payments in lieu of corporate taxes receivable/payable	(5,756)	153,638
Future income taxes	63,888	(441,741)
Construction deposits	-	(37,930)
Deferred revenue	43,609	
Employee future benefits	(3,440)	(47,325)
	861,884	1,864,056
Cash flows from investing activities		
Expenditures on property, plant and equipment	(2,098,370)	(2,281,110)
Net increase (decrease) in regulatory assets	(228,698)	(640,691)
	(2,327,068)	(2,921,801)
Cash flows from financing activities		
Repayment of amount due to shareholder	-	(1,122,519)
Customer and retailer deposits	19,800	(19,472)
Loan advances	2,135,000	1,422,519
Loan repayments	(147,876)	-
Net decrease in other long-term liabilities	-	(29,181)
Dividends paid	(300,000)	(300,000)
	1,706,924	(48,653)
Increase (decrease) in cash during the year	241,740	(1,106,398)
Cash (bank indebtedness), beginning of year	(824,439)	281,959
Bank indebtedness, end of year	$ (582,699)	$ (824,439)
Represented by		
Cash and bank	$ 177,301	$ 135,561
Bank indebtedness	(760,000)	(960,000)
	$ (582,699)	$ (824,439)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

December 31, 2010

Nature of Business

The corporation was incorporated under the laws of the Province of Ontario on December 22, 1999 in accordance with the provincial government's Electricity Act, 1998. Subsequently, Midland Power Utility Corporation, Mid-Ontario Energy Services Inc. and Community One-Lan Solutions Inc. were amalgamated on May 1, 2002. The newly formed corporation operating as Midland Power Utility Corporation is licensed by the Ontario Energy Board ("OEB") as an electricity distributor. The principal activity of the corporation is to distribute electricity to the Town of Midland. The corporation is regulated by the OEB and adjustments to the distribution and power rates require OEB approval.

Basis of Accounting

The financial statements of Midland Power Utility Corporation are prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook"), issued under the authority of the Ontario Energy Board Act, 1998.

Due to the regulatory framework, the timing of recognition of revenues and expenses and the measurement of certain assets and liabilities may differ from that otherwise expected under Canadian generally accepted accounting principles (GAAP) for non-rate regulated enterprises. Please refer to accounting policies for Spare Transformers and Meters, Post 1999 Contributed Capital, Regulatory Assets and Liabilities, Payments in lieu of corporate income taxes and capital taxes and Ontario Price Credit Rebates.

The financial statements reflect the significant accounting policies summarized below.

Regulation and Rate Setting

The corporation is required to follow regulations as set by the OEB. The OEB approves and sets rates for the distribution of electricity, ensures distribution companies fulfill their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers.

The OEB sets rates on an annual basis with rates becoming effective on May 1st through April 30th of the following year. The regulation and monitoring of Ontario's Energy Sector is completed by the OEB through application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

December 31, 2010

Regulatory Assets and Liabilities

The corporation has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory assets or regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition.

Regulatory assets represent future revenues associated with certain costs, incurred in current or prior period(s), that are expected to be recovered through the rate setting process.

Regulatory liabilities represent future reductions or limitations of revenue increases associated with amounts that are expected to be refunded to customers.

Regulatory assets and liabilities can arise from differences in amounts billed to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the corporation in the wholesale market administered by the Independent Electricity System Operator "IESO" after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act and deferred in anticipation of their future recovery in electricity distribution service charges.

In the absence of rate regulation the regulatory assets and liabilities would be recognized in income in the period to which they relate.

Inventory

Inventory consists of parts and supplies valued at the lower of cost and net realizable value. Cost is generally determined on the first-in, first-out basis.

Seasonality of Operations

The corporation's operations are seasonal. Electricity consumption is typically highest in the summer and winter months, July through September and January through March.

Spare Transformers and Meters

Spare transformers and meters are held to back up plant in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired.

According to the criteria prescribed by the OEB in the AP Handbook the spare transformers and meters are treated as capital assets and included in the distribution systems category. Under Canadian GAAP for unregulated businesses the spare transformers and meters would be treated as inventory.

Post 1999 Contributed Capital

Post 1999 contributed capital consists of third party contributions toward the cost of constructing distribution assets collected after January 1, 2000, and are recorded with property, plant and equipment as a contra account. Contributions are amortized at rates corresponding with the useful lives of the related property, plant and equipment. Canadian GAAP provides no specific guideline on the accounting treatment for this type of contribution.

Post 1999 contributed capital is included in distribution system in the schedule of capital assets.

Long-term Investments

The corporation records its long-term investments using the cost method.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased.

Goodwill is not amortized but is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

Goodwill impairment is assessed based on a comparison for the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill.

When the carrying amount of goodwill exceeds the implied fair value of goodwill an impairment loss is recognized in an amount equal to the excess as a charge against the results of operations.

Management has decided that a valuation was not necessary and therefore impairment of goodwill could not be assessed.

Construction Deposits

Construction deposits represent maintenance deposits and deposits for recoverable work.

Customer Deposits

Customer deposits represent amounts collected from customers to guarantee the payment of energy bills. The customer deposits liability includes interest credited to customers' deposit accounts, with interest expense recorded to offset this amount. Deposits expected to be refunded to customers within one year are classified as a current liability.

December 31, 2010

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, engineering costs, and interest on funds used during construction when applicable. Also included in property, plant and equipment are the costs of capital assets constructed by developers or customers and contributed to the corporation.

Upon disposal the cost and accumulated amortization related to the asset are removed and any gains or losses on disposal are credited or charged to other income on the statement of operations.

Amortization is provided using the following method and annual rates:

Buildings	20 years	straight-line basis
Distribution system	25 years	straight-line basis
Supervisory equipment	15 years	straight-line basis
Rolling stock	5 - 8 years	straight-line basis
Shop equipment	10 years	straight-line basis
General office equipment	10 years	straight-line basis
Stores equipment	10 years	straight-line basis
Computer equip/software	5 years	straight-line basis
Wireless equipment	10 years	straight-line basis

Spare and replacement parts included in property, plant and equipment are not amortized until they are put into service.

Construction in progress is included in property, plant and equipment and not amortized until the project is complete.

Pension Plan

The corporation offers a pension plan for its full-time employees through the Ontario Municipal Employee Retirement System ("OMERS"). OMERS is a multi-employer, contributory, public sector pension fund established for employees of municipalities, local boards and school boards in Ontario. Participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation accounts for its participation in OMERS as a defined contribution plan and recognizes the expense related to this plan as contributions are made.

Post-employment Benefits

Employee future benefits other than pension provided by the corporation include life insurance premiums paid by the corporation. This plan provides benefits to employees who retired prior to May 2002.

Standards issued by The Canadian Institute of Chartered Accountants with respect to accounting for employee future benefits require the corporation to accrue for its obligations under other employee benefit plans and related costs, net of plan assets.

The cost of post-employment benefits offered to retirees are actuarially determined using the projected benefit method and based on assumptions that reflect management's best estimate.

Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on the accrual basis. The revenue includes cycles billed during the year plus an estimate for unbilled revenue. The unbilled revenue is calculated by prorating the actual consumption of electricity by customers since their last meter reading date, based on meter readings subsequent to year end, for consumption to December 31, 2010. Actual results could differ from estimates made of electricity usage.

Other revenues, which include revenues from pole attachment, customer demand work, and other miscellaneous revenues are recognized at the time the service is provided.

Ontario Price Credit Rebates

Consumers other than designated consumers who annually utilize more than 250,000 kWh were eligible to receive Ontario Price Credit Rebates ("OPC Rebates") from the IESO to the extent that electricity prices exceed certain prescribed thresholds.

The corporation and other electricity distributors are required to pass these rebates to eligible customers and other market participants (including retailers). The corporation includes amounts due to eligible customers and market participants in accounts payable and accrued liabilities.

These rebates are recognized as a reduction in the cost of power purchased. (See Note 21)

The OPC rebates ended effective January 31, 2009.

Use of Estimates and Measurement Uncertainty

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date.

Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered which reflect an appropriate allowance for unrecoverable amounts. The useful lives of property, plant and equipment have been estimated in order to reflect the appropriate net book values of the assets.

Due to inherent uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the accounting policies.

Payment in Lieu (PIL) of Corporate Income Taxes and Capital Taxes

The corporation is a municipal electricity utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Each taxation year, the corporation is required to make payments in lieu of corporate income taxes and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated based on the rules for computing taxable income and taxable capital outlined in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) taking into account any modifications made by the Electricity Act, 1998, and related regulations.

The corporation provides for payments in lieu of corporate income taxes and capital taxes related to its regulated business using the liability method of accounting.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to regulatory assets and liabilities. The net balance represents future income taxes that flow through the rate-making process.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International Financial Reporting Standards

On February 13, 2008, the Canadian Accounting Standards Board ["AcSB"] confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP, with the remaining standards to be adopted at the change over date.

Continued...

New Accounting Pronouncements continued

Prior to the developments noted below, the Corporation's IFRS conversion project was proceeding as planned to meet the January 1, 2011 conversion date. The Corporation has an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements. The Corporation believes that the impact on its financial statements could be material.

On September 10, 2010, the AcSB granted an optional one year deferral of IFRS adoption for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ["IASB"] in regard to the rate-regulated project which is assessing the potential derecognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

Given these recent developments and due to the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ["RRA"] standard under IFRS and the potential material impact of RRA on the Corporation's financial statements, the Corporation has decided to elect the optional one year deferral of its adoption of IFRS. Accordingly, the Corporation will continue to prepare its financial statements in accordance with Canadian GAAP for 2011.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. During the deferral period, the Corporation will continue to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts.

December 31, 2010

1. Cash and Bank

The corporation's bank accounts are held at one chartered bank. The bank account earns interest at a variable rate.

2. Other Accounts Receivable

	2010	2009
Recoverable work	$ 53,187	$ 28,038
Merchandise and jobbing receivable	-	1,232
Streetlight labour receivable	-	1,450
Miscellaneous accrued receivables	26,943	45,546
HST receivable	231,307	-
	$ 311,437	$ 76,266

3. Related Party Transactions

The following summarizes the corporation's related party transactions for the year with its shareholder, the Corporation of the Town of Midland:

	2010	2009
Revenue		
- Electricity charges	$ 708,203	$ 579,199
- Maintenance of streetlighting and other services	149,198	76,477
Expenses		
- Municipal taxes	40,685	41,968
- Lease fees for substation properties	49,980	49,980
- After hours answering service	20,000	20,000
- Communications antenna	20,000	20,000
- Vehicle servicing, job recoveries and miscellaneous	9,268	15,315
- Interest expense on promissory note payable	-	36,278
Dividends paid	300,000	300,000

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product or provision of service.

Continued...

3. Related Party Transactions continued

At the end of the year, the amounts due from and (to) its shareholder, the Corporation of the Town of Midland, are as follows:

	2010	2009
Trade receivable, unsecured, due on demand	$ **81,316**	$ 26,025
Trade payable, unsecured, due on demand	$ **(5,352)**	$ (2,531)

The board of directors approved a $300,000 dividend that was paid to the Town of Midland in each of the 2009 and 2010 years. Subsequent to year-end, the board of directors approved and paid a $400,000 dividend for 2011.

The board of directors of Midland Power Utility Corporation received compensation and were reimbursed for certain administrative costs for the year in the amount of $28,486 (2009 - $27,591). These transactions were in the normal course of operations and were measured at the exchange amount.

The corporation paid $20,775 (2009 - $20,325) in fees to Cornerstone Hydro Electric Concepts Association Inc. (CHEC) (See Note 8).

The corporation paid $43,239 (2009 - $49,484) in fees to Utility Collaborative Services Inc. (UCS) for items such as information technology hosting and software licensing (See Note 8).

4. Payments in Lieu of Corporate Income Taxes

	2010	2009
Income before provision for PILs	$ **890,403**	$ 900,698
Statutory Canadian federal and provincial tax rate	**30.00%**	33.00%
Provision for PILs at statutory rate	**267,121**	297,230
Small business deduction	**(64,998)**	(69,219)
Cumulative eligible capital deduction	**(18,986)**	(22,457)
Net increase in regulatory assets	**(37,295)**	(84,992)
Changes to statutory tax rate	**5,171**	-
Amortization expense in excess of capital cost allowance	**(54,174)**	(25,661)
Change in pension post retirement plan (not taxable)	**(1,032)**	(15,617)
Other items	**763**	(4,298)
Corporate minimum tax	**(11,994)**	11,994
Adjustment to tax provision	**1,231**	(18,107)
Total provision	$ **85,807**	$ 68,873
Effective tax rate	**9.64%**	7.65%

5. Future Income Taxes

The corporation accounts for the differences between the financial statement carrying value and tax basis of its assets and liabilities following the liability method in accordance with CICA Handbook Section 3465.

Significant components of the corporation's future tax assets (liabilities) are as follows:

	2010	2009
Employee future benefits	$ **14,925**	$ 19,516
Property, plant and equipment	**551,720**	602,133
Long-term future income tax asset	$ **566,645**	$ 621,649
Goodwill and land rights	$ **(22,711)**	$ (13,508)
Regulatory liabilities net of assets	**(166,081)**	(166,400)
Long-term future income tax liability	$ **(188,792)**	$ (179,908)
Net future income tax asset	$ **377,853**	$ 441,741

The offsetting entry to this net future income tax asset is a credit to regulatory liabilities (See Note 7).

6. Property, Plant and Equipment

	2010		2009	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Land	$ 381,738	$ -	$ 381,738	$ -
Land rights	32,555	15,060	32,555	15,060
Buildings	984,361	411,026	966,206	380,049
Distribution system	17,716,996	8,926,461	14,636,882	8,333,143
Supervisory equipment	452,129	270,652	357,012	248,799
Rolling stock	1,047,274	527,261	1,047,274	418,871
Shop equipment	352,201	280,442	344,080	268,477
General office equipment	259,029	228,700	251,230	222,236
Stores equipment	8,610	8,610	8,610	8,610
Computer equip/software	804,662	644,974	736,096	581,554
Wireless equipment	69,891	69,891	69,891	69,891
Spare and replacement parts	146,608	-	190,639	-
Construction in progress	-	-	1,072,527	-
	$ 22,256,054	$ 11,383,077	$ 20,094,740	$ 10,546,690
Net book value		$ 10,872,977		$ 9,548,050

During the year the corporation purchased property, plant and equipment totalling $2,098,370 (2009 - $2,281,110). Financing of $1,235,000 (2009 - $300,000) was used to make the capital purchases and the remainder was paid with cash.

The net book value of stranded meters related to the deployment of smart meters is included in property, plant and equipment in the distribution system category. In the absence of rate regulation, property, plant and equipment would have been decreased to remove the net book value of these stranded meters. The total net book value of all meters included in property, plant and equipment as at December 31, 2010 is $399,382 (2009 - $414,416). The decrease required in the absence of rate regulation is undeterminable as the components of the remaining net book value are not readily determinable.

7. Regulatory Assets and Liabilities

	2010	2009
Net regulatory assets (liabilities) consist of:		
Smart meter initiatives	$ **969,333**	801,267
Other regulatory assets - Hydro One incremental costs	**7,668**	3,661
Other regulatory assets - IFRS transition costs	**6,586**	7,150
Settlement variances	**(171,204)**	60,614
Special purpose charge variance	**35,246**	-
Carrying charges calculated using OEB specified rate	**12,518**	45,716
Extraordinary event variance	**228,215**	-
Late payment penalty settlement	**31,756**	-
Net future income tax liability	**(377,853)**	(441,741)
Regulatory Asset Recovery Accounts (RARA):		
Regulatory asset balances up to April 30, 2006	**-**	1,008,899
Recovery of regulatory assets beginning May 1, 2006	**-**	(1,072,352)
Disposition of 2005 - 2007 account balances	**(261,109)**	(261,109)
Repayment of 2005 - 2007 account balances	**197,105**	71,752
Disposition of 2008 account balances	**(306,317)**	-
Repayment of 2008 account balances	**80,611**	-
	$ **452,555**	$ 223,857

Smart Meter Initiatives

The smart meter regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario by 2010. During 2006 the OEB developed recommendations on smart meters with regard to cost recovery during the phase-in period of this equipment. The OEB stated that given the increased need for electricity and the importance of conservation, specific funding for smart meters could be included in the 2006 rates for all Local Distribution Companies (LDCs). Variance accounts were established to track revenues collected with respect to smart meters and associated costs of the initiatives. The majority of the installation of all smart meters within its service territory was completed in 2009. The OEB approved the request to add a rate rider of $2.00 ($1.00 prior to May 1, 2010) per customer per month to fund Smart Meter activities.

In connection with its smart meter initiatives, the corporation has incurred costs in 2010 amounting to $308,946 (2009 - $866,695). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In absence of rate regulation, revenues would have been higher in 2010 by $132,368 (2009 - $47,579) and amortization higher in 2010 by $76,705 (2009 - $22,674).

Other Regulatory Assets - Hydro One Incremental Costs

The OEB has approved Other Regulatory Assets, "Sub-account Incremental Capital Charges", for distributors to record the charges arising from the capital rate relief rider. Interest carrying charges, calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates, are applicable for amounts recorded. The new incremental capital charge arises from an incremental capital module approved for Hydro One, which was effective on May 1, 2009 but was implemented on June 1, 2009. In the absence of rate regulation, expenses in 2010 would have been $4,007 higher (2009 - $3,661).

Continued...

7. Regulatory Assets and Liabilities continued

Other Regulatory Assets - IFRS transition costs

The OEB has approved the collection from customers to cover the expected one-time costs of implementing International Financial Reporting Standards (IFRS). Collections of $25,000 per year for 2009 - 2012 are off-set by OEB approved expenses in this variance account. In the absence of rate regulation, revenues would have been $25,000 higher in 2010 (2009 - $25,000) and expenses would have been $24,436 higher (2009 - $32,150). The deferred balance continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance account has not yet been determined by the OEB.

Settlement Variances

Settlement variances represent the differences between amounts charged by the corporation to its customers based on regulated rates and the corresponding cost incurred by the corporation in the wholesale market administered by the IESO. Under the OEB's direction, the corporation has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the corporation has deferred these recoveries in accordance with the AP Handbook.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2010 would have been $465,657 higher (2009 - $304,359 lower). The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the remaining variance has not been determined by the OEB.

Special Purpose Charge Variance

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ["SPC"] assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB has assessed the corporation $82,891 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 [the "SPC Regulation"]. In accordance with Section 9 of the SPC Regulation, the corporation will be allowed to recover this balance. The recovery is to be achieved over a one-year period, starting May 1, 2010.

This variance account relates to the difference between the amount remitted to the Ministry of Finance for LDC's SPC assessment, and the amounts recovered from customers, which commenced on May 1, 2010. Carrying charges apply to the monthly opening balance in the variance account. The SPC Regulation states that the corporation shall apply to the OEB no later than April 15, 2012 for an order authorizing the disposition of any remaining debit or credit balance in the SPC variance account. As at December 31, 2010, the account consists of the corporation's assessment offset by eight months of recoveries. In the absence of rate regulation, revenue for the year would have been $47,645 higher and operating expenditures would have been $82,891 higher.

Continued...

7. Regulatory Assets and Liabilities continued

Carrying Charges

Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. In the absence of rate regulation, other revenues would have been higher by $3,655 (2009 - $8,868 lower).

Extraordinary Event Variance

The OEB sets out procedures that LDCs must follow for extraordinary event costs through the Accounting Procedures Handbook ("AP Handbook"). An extraordinary event expense may be considered for recovery if the LDC is able to establish that the expense was clearly outside the base upon which rates were derived, that the expense had a significant influence on the operation of the LDC, that the expense was attributable to an event outside of management's ability to control and that the expense was prudently incurred.

On June 23, 2010 an F2 tornado hit Midland with high winds reaching between 180 kilometers and 240 kilometers an hour as confirmed by Environment Canada. As at December 31, 2010, Midland Power Utility Corporation had incurred costs of $355,873 relating to the repair and replacement of downed power lines and other damage that resulted from the tornado.

Management believes the LDC has met the requirements under the AP Handbook for the extraordinary event costs. The OEB allows LDCs to apply for recovery of expenditures related to the tornado through future rates by way of a rate rider or through the capitalization of costs.

Management has determined that as at December 31, 2010, $228,215 of the $355,873 is related to expenses incurred outside the current rate base. Once all costs of the tornado are established, management and the Board of Directors of Midland Power Utility Corporation will make the determination whether to apply to the OEB for a rate rider to recover these costs or to include these costs in capital. In the absence of rate regulation, capital in 2010 would have been $228,215 higher.

Late Payment Penalty Settlement

The late payment penalties settlement account relates to the settlement costs accrual associated with the late payment charges class action (See Note 13). The company has accrued a liability and a corresponding regulatory asset in the amount of $31,756 as at December 31, 2010. In the absence of rate regulation, operating expenses for the year ended December 31, 2010, would have been $31,756 higher. The amount will be recovered from the ratepayers over a one year period from May 1, 2011 to April 30, 2012.

Continued...

December 31, 2010

7. Regulatory Assets and Liabilities continued

Future Income Tax Regulatory Liability

This regulatory liability account relates to the expected future electricity distribution rate adjustments for customers arising from timing differences in the recognition of future taxes.

On January 1, 2009, the corporation began to account for the differences between its financial statement carrying value and tax basis of assets and liabilities following the liability method in accordance with CICA Handbook Section 3465 (See Note 5).

Regulatory Asset Recovery Accounts (RARA)

The RARA consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

The rate application for 2009, approved by the OEB, included the disposition of regulatory liabilities accumulated from January 1, 2005 - December 31, 2007 plus projected interest up to April 30, 2009. This phase of repayment is for a two year period with rates effective May 1, 2009.

The rate application for 2010, approved by the OEB, included the disposition of regulatory liabilities from January 1, 2008 - December 31, 2008 plus projected interest up to April 30, 2010. This phase of repayment is for a two year period with rates effective May 1, 2010.

Fair Value of Regulatory Assets and Regulatory Liabilities

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the regulator in determining the asset's treatment for rate setting purposes. Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

8. Long-term Investments

	2010	2009
Cornerstone Hydro Electric Concepts Association Inc. (CHEC), incorporated without share capital. The cost for the investment was $Nil and therefore not included in these financial statements	$ -	$ -
Utility Collaborative Services Inc. (UCS), recorded using the cost method, 1 common share, 10% interest (2009 - 12.50% interest)	100	100
	$ 100	$ 100

Continued...

8. Long-term Investments continued

Cornerstone Hydro Electric Concepts Association Inc. (CHEC) is an association of twelve electricity distribution utilities modelled after a cooperative to share resources and proficiencies.

Utility Collaborative Services Inc. (UCS) offers standards-based back office services. The collaboration allows leverage in the reduction of costs for items such as information technology hosting and software licensing.

9. Bank Indebtedness

The corporation has a line of credit with an authorized limit of $4,500,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances is calculated using the bank's prime rate, calculated and payable monthly. It is secured by a general security agreement covering all assets except real property.

As at December 31, 2010 the corporation had drawn a balance of $760,000 on this credit facility. The corporation's line of credit has been pledged as security for the letter of credit provided to the Independent Electricity Systems Operation ("IESO") (see Note 13). As a result, the corporation's access to the $4,500,000 credit facility mentioned above is limited to $2,644,270.

The agreement governing the line of credit facilities contains certain covenants as described in Note 22.

10. Accounts Payable and Accrued Liabilities

	2010	2009
IESO accounts payable	**$ 1,517,249**	$ 1,268,007
Trade accounts payable	**872,538**	1,217,835
Accrued liabilities	**601,197**	657,640
Customer credit balances	**306,901**	442,295
Deferred charges	**-**	607
Hydro One low voltage charges	**-**	29,181
	$ 3,297,885	$ 3,615,565

11. Long-term Debt

	2010	2009
Infrastructure Ontario Short-term Construction Loan Advance - 1.74% floating rate, interest payable monthly, construction loan rate floats throughout the term of the loan until replaced by a debenture, no principal repayable until conversion to a debenture is completed, secured by a general security agreement covering a second charge on all assets and real property, due on demand	**$ 900,000**	$ 1,422,519
Infrastructure Ontario Debenture - 2.91% fixed rate, $30,000 principal repayable semi-annually plus interest on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2015	**270,000**	-
Infrastructure Ontario Debenture - 3.91% fixed rate, $56,126 principal repayable semi-annually plus interest, on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2020	**1,066,393**	-
Infrastructure Ontario Debenture - 3.91% fixed rate, $61,750 principal repayable semi-annually plus interest, on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2020	**1,173,250**	-
	3,409,643	1,422,519
Current portion of long-term debt	**1,195,752**	1,422,519
	$ 2,213,891	$ -

Total construction advances of $5.5 million have been approved by Infrastructure Ontario. At December 31, 2010, the corporation had undrawn credit capacity under this facility of approximately $1,942,481.

On March 1, 2011 a 10 year debenture in the amount of $1,200,000 was received by the corporation at fixed a rate of 4%.

The agreement governing these credit facilities contains certain covenants as described in Note 22.

Continued...

11. Long-term Debt continued

Principal repayments for each of the five subsequent years and thereafter are as follows:

2011	$ 1,195,752
2012	295,752
2013	295,752
2014	295,752
2015	265,752
Thereafter	1,060,883
	$ 3,409,643

12. Employee Future Benefits

During 2003 the corporation discontinued its post-retirement life insurance, dental and health benefits to all employees. As at December 31, 2010, there are only six (2009 - six) retirees who retain the post-retirement life insurance benefit. Information about the post-retirement life insurance benefit plan is as follows:

	2010	2009
Accrued benefit liability, beginning of year	**$ 78,065**	$ 125,390
Expense for the year	**(3,440)**	(2,927)
Change in post-retirement plan - (d) below	**-**	(44,398)
Projected accrued benefit obligation at December 31	**$ 74,625**	$ 78,065

An actuarial report was performed and dated January 20, 2010. The actuarial valuation was performed on the post-retirement obligations sponsored by the corporation as at December 31, 2009. The next actuarial valuation will be performed December 31, 2012.

The main actuarial assumptions employed for the valuations are as follows:

(a) General inflation: Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% per annum.

(b) Interest (discount) rate: The obligation, as at December 31, 2010, of the present value of future liabilities was determined using an annual discount rate of 6.0%. This rate reflects the assumed long-term yield on high quality bonds.

(c) Expenses: The assumption was made that 10% of benefits are required for the cost of sponsoring the program for life insurance.

(d) Change in Post-Retirement Plan: The accrued benefit obligation was decreased in 2009 over the 2006 valuation mainly as a result of a higher discount rate assumption and the death of one retiree.

13. Contingencies

i) Griffith et al. v. Toronto Hydro-Electric Commission et al.

An action was brought under the Class Proceedings Act, 1992. The plaintiff class sought $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code.

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge and that settlement was approved by the Ontario Superior Court.

In 2007, Enbridge filed an application to the Ontario Energy Board ("OEB") to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved recovery of the said amounts from ratepayers over a five year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs.

On February 10, 2009, the Superior Court of Justice approved the settlement agreement related to the Class action proceeding on late payment penalties against Union Gas. The settlements from Enbridge and Union Gas cases had precedent-setting implications for the outcome of this case.

Similar to the natural gas utilities, the LDCs were successful in reaching a settlement dated April 21, 2010, the principal terms of which were the following:

a) LDCs would collectively pay $17 million in damages
b) Payment would not be due until June 30, 2011
c) Amounts paid, after deduction for counsel fees, costs and applicable interest, would be paid to the Winter Warmth Fund or similar charities; and
d) LDCs would be at liberty to seek Ontario Energy Board permission to recover settlement costs through rates.

The total cost agreed to in the settlement was $18,382,125. This amount includes the estimated settlement payment of $17 million, $700,000 estimated in legal costs, $632,125 in taxes and $50,000 in publication costs related to various court orders and notices.

Continued...

13. Contingencies continued

The recovery amount applicable to Midland Power Utility Corporation is $31,756. This amount has been recorded in the accrued liabilities and off-set by a regulatory asset of the same amount (See Note 7).

On February 22, 2011, the Ontario Energy Board ordered that the costs and damages arising from the class action would be recovered from all ratepayers of the affected electricity distributors. The corporation has decided that they will proceed with the recovery from ratepayers over a one year period.

(ii) Letter of Credit

The corporation is contingently liable as a guarantor for a letter of credit for $1,095,730 with its bank provided to the Independent Electricity Systems Operator (IESO) to secure the corporation's hydro purchase obligations.

(iii) Insurance claim

The corporation is contingently liable to pay an insurance deductible of $1,000 in relation to an action against the corporation (see note 19).

14. Share Capital

The authorized share capital of the corporation is an unlimited number of common and preference shares. The issued share capital is as follows:

	2010	2009
1,000 Common shares	**$ 6,880,984**	$ 6,880,984

15. Financial Instruments

All financial instruments are included on the balance sheet and are measured either at fair market value or, in limited circumstances, at cost or amortized cost. The corporation classifies its financial instruments into one of the following categories:

Held-for-trading
Held-for-trading is comprised of cash and bank. This instrument is carried in the balance sheet at fair value with changes in fair value recognized in the income statement. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Loans and receivables
Loans and receivables are comprised of accounts receivable and unbilled revenue. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest rate method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other financial liabilities
Other financial liabilities are comprised of bank indebtedness, accounts payable and accrued liabilities, customer and construction deposits, amounts due to shareholder, and long-term debt. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are netted against the amount initially recognized.

The Corporation's carrying value and fair value of financial instruments consist of the following:

	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets				
Cash and bank	**177,301**	**177,301**	135,561	135,561
Accounts receivable	**3,573,889**	**3,573,889**	3,105,611	3,105,611
Long-term investments	**100**	**undeterminable**	100	undeterminable
Due from shareholder	**81,316**	**81,316**	26,025	26,025
Liabilities				
Bank indebtedness	**760,000**	**760,000**	960,000	960,000
Accounts payable	**3,297,885**	**3,297,885**	3,615,565	3,615,565
Due to shareholder	**5,352**	**5,352**	2,531	2,531
Customer deposits	**348,345**	**348,345**	328,545	328,545
Construction deposits	**17,186**	**17,186**	17,186	17,186
Long-term debt	**3,409,643**	**3,409,643**	1,422,519	1,422,519

Continued...

15. Financial Instruments continued

The estimated fair values of financial instruments as at December 31, 2010 and December 31, 2009 are based on relevant market prices and information available at the time. The fair value estimates are not necessarily indicative of the amounts that the corporation may receive or incur in actual market transactions. These estimates are subjective in nature and involve uncertainties and matters of significant judgment and therefore cannot be determined with precision. Changes in assumptions could significantly affect the estimates.

Determination of fair values

(a) The fair values of cash and bank, accounts receivable, unbilled revenue, current customer deposits, accounts payable and accrued liabilities and bank indebtedness approximate their carrying values because of the short maturity of these instruments.

(b) Long-term investments include common shares of private companies accounted for by the cost method. These investments are not publicly traded and, therefore, fair values are not practicable to determine.

(c) The fair value of each of the corporation's long-term debt instruments is based on the amount of future cash flows associated with each instrument discounted using an estimate of what the corporation's current borrowing rate for similar debt instruments of comparable maturity would be.

It is management's intention not to renew the long-term debt until its maturity.

16. Net Service Revenue

	2010	2009
Service revenue	$ **135,649**	$ 102,751
Service costs	**(100,470)**	(59,133)
Net service revenue	$ **35,179**	$ 43,618

December 31, 2010

17. Other Net Revenue

		2010		2009
Carrying charges on regulatory balances	$	**3,655**	$	(8,868)
Gain (loss) on disposal		**(2,543)**		13,025
Interest earned		**3,362**		37,483
Late payment charges		**19,795**		20,871
Ontario Power Authority management fees		**34,246**		46,594
Office rental		**50,940**		53,148
Other		**108,837**		107,033
Pole rental		**31,954**		37,018
	$	**250,246**	$	306,304

18. Statement of Cash Flows

		2010		2009
Interest paid	$	**66,052**	$	49,199
Interest received	$	**3,362**	$	37,483
PILs paid	$	**90,332**	$	270,996
PILs received	$	**-**	$	361,497

19. Liability Insurance

The corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members.

The corporation is named as a defendant in an action commenced on July 31, 2009 in the Ontario Superior Court of Justice. The claim is for $350,000 in damages plus interest and legal costs and is as a result of a fire that the Plaintiff is claiming was caused by an electrical failure due to the negligence of Midland Power Utility Corporation. The corporation is denying any liability and has passed this action along to their insurer, Mearie. If held liable, the corporation will be required to pay the deductible of $1,000.

20. Pension Agreements

The corporation makes contributions to the Ontario Municipal Employee Retirement System (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to more than 400,000 active and retired members and approximately 928 employers. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2009. The results of this valuation disclosed total actuarial liabilities of $54,253 (2008 - $50,080) million in respect of benefits accrued for service with actuarial assets at that date of $52,734 (2008 - $49,801) million, indicating an actuarial deficit of $1,519 (2008 - $279) million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the corporation does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for the plan were 6.4% (2009 - 6.3%) for employees earning up to $47,200 (2009 - 46,300) and 9.7% (2009 - 9.5%) thereafter. The amount contributed to OMERS for 2010 was $125,939 (2009 - $120,379).

21. Ontario Price Credit Rebates

During the year ended December 31, 2009 the corporation received OPC rebates pertaining to consumption for the period from August 1, 2008 to January 31, 2009. These rebates totalling $108,500 were recognized as a reduction in the cost of power purchased.

There were no OPC rebates received in 2010.

22. Capital Disclosures

The corporation considers its capital to be its share capital and retained earnings. The corporation's main objectives when managing capital are to: i) ensure sufficient liquidity to support its financial obligations and execute its operating and strategic plans, ii) minimize the cost of capital while taking into consideration current and future industry, market and economic risks and conditions, iii) maintain an optimal capital structure that provides necessary financial flexibility while also ensuring compliance with any financial covenants, and iv) provide an adequate return to its shareholder.

The corporation relies predominately on its cash flow from operations to fund its dividend distributions to its shareholder. This cash flow is supplemented, when necessary, through the borrowing of additional debt.

As part of existing debt agreements, financial covenants are monitored and communicated, as required by the terms of credit agreements, on an annual basis by management to ensure compliance with the agreements.

The bank indebtedness covenants require the corporation to maintain a minimum Interest Coverage Ratio of 2.5 times and to maintain a maximum Total Debt to Capitalization of 0.60 to 1. The corporation was in compliance with these covenants as at December 31, 2010.

The Infrastructure Ontario loan covenants require the corporation to provide notification prior to any new debt issuance and to seek approval where the Debt Service Coverage Ratio falls below 1 to 1 at any time; such ratio is otherwise tested and calculated as of the end of each fiscal year. The corporation is also required to maintain a maximum Debt to Capital ratio of 0.60 to 1 and a minimum current ratio of 1.1 to 1 to be tested and calculated as of the end of each fiscal year. The corporation is in compliance with these covenants as at December 31, 2010, except for the current ratio. Infrastructure Ontario has waived the current ratio covenant for fiscal 2010 only.

Management monitors the following key ratios to effectively manage capital:

	2010	2009
a) Debt Service Coverage Ratio:	1.48:1	4.09:1
b) Debt to Capital:	0.34:1	0.24:1
c) Current ratio:	0.78:1	0.61:1

23. Financial Risk Management

As part of its operations, the corporation carries out transactions that expose it to financial risks such as credit, liquidity and market risks.

The following is a discussion of risks and related mitigation strategies that have been identified by the company for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

Credit risk

Credit risk is the risk that one party to a financial instrument might not meet its obligations under the terms of the financial instrument. The maximum credit exposure is limited to the carrying amount of cash and receivables presented on the balance sheet.

Financial instruments that potentially subject the corporation to a significant concentration of credit risk consist primarily of cash. The corporation limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The corporation maintains cash with one major financial institution. Eligible deposits are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The corporation is exposed to credit risk related to accounts receivable arising from its day-to-day electricity and service revenue. Exposure to credit risk from accounts receivable is limited due to the corporation's large and diverse customer base. Moreover, the corporation holds as collateral customer and construction deposits, which are recognized as liabilities on the balance sheet. The Ontario Energy Board has prescribed certain rules for the payment of deposits by customers. Although these rules limit the risk of the company, no deposits are required by customers who have shown good payment history for the previous 24 month period. The company does not have any material accounts receivable balances greater than 90 days outstanding. As a result, the company believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the income statement. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

The company's accounts receivable are not subject to a significant concentration of credit risk because they are distributed over a large customer base.

The value of accounts receivable, by age, and the related bad debt provision are presented in the following table. The accounts receivable balance consists of energy, other and unbilled revenue receivables.

Unbilled revenue represents amounts to which the corporation has a contractual right to receive cash through future billings but are unbilled at period-end. Unbilled revenue outstanding is considered current.

Continued...

December 31, 2010

23. Financial Risk Management continued

Accounts Receivable

	2010	2009
Under 30 days	$ 3,473,421	$ 3,177,613
30 to 60 days	17,591	16,507
61 to 90 days	66,895	4,774
Over 90 days	209,984	39,560
	3,767,891	3,238,454
Provision	194,002	132,843
Total accounts receivable	$ 3,573,889	$ 3,105,611
Represented by:		
Energy revenue accounts receivable	$ 1,168,187	$ 847,458
Other accounts receivable	311,437	76,266
Unbilled energy revenue	2,094,265	2,181,887
	$ 3,573,889	$ 3,105,611

Liquidity risk
Liquidity risk is the risk that the corporation will encounter difficulty in meeting obligations associated with financial liabilities. The corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation's reputation. The corporation's exposure is reduced by cash generated from operations and their undrawn credit facility. The corporation engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting.

Liquidity risks associated with financial commitments are as follows:

	0 - 3 mo	3 mo - 1 yr	1 - 5 yr	Termless
Bank indebtedness	$ 760,000	$ -	$ -	$ -
Accounts payable and accrued liabilities	3,297,885	-	-	-
Construction loan	1,195,752	-	-	-
Due to shareholder	5,352	-	-	-
Customer deposits	-	149,868	198,477	-
Deferred revenue	10,902	32,707	-	-
Construction deposits	-	17,186	-	-
Employee future benefits	-	3,440	13,760	57,425
Total	$ 5,269,891	$ 203,201	$ 212,237	$ 57,425

Continued...

December 31, 2010

23. Financial Risk Management continued

Market risk
Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the corporation's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The corporation does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The corporation had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2010.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The corporation is exposed to interest rate fluctuations on its cash and bank, undrawn credit facilities and Infrastructure Ontario construction loan which bear a floating rate of interest. The corporation's exposure to interest rate risk is limited by cash from operations making it possible to maintain a high interest coverage ratio. As at December 31, 2010, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

Midland Power Utility Corporation

Financial Statements
For the year ended December 31, 2011

Midland Power Utility Corporation

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Midland Power Utility Corporation
Financial Statements
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BDO Canada LLP
186 Hurontario Street, Suite 202
Collingwood ON L9Y 4T4 Canada

Independent Auditor's Report

To the Shareholder of Midland Power Utility Corporation

We have audited the accompanying financial statements of Midland Power Utility Corporation, which comprise the balance sheet as at December 31, 2011, the statements of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

Canadian generally accepted accounting principles require that a goodwill impairment loss be recognized when the carrying amount of the goodwill of a reporting unit exceeds the fair value of the goodwill. A valuation of the corporation is required in order to determine whether or not goodwill has been impaired. Management has decided that the valuation is not necessary at this time. As a result, we are unable to determine the adjustment, if any, to goodwill, expenses, net income and retained earnings as well as related disclosure that would be necessary to reflect the impairment, if any, of goodwill.

Qualified Opinion

In our opinion, except for the effects of the matter described in the Basis for Qualified Opinion paragraph, the financial statements present fairly, in all material respects, the financial position of Midland Power Utility Corporation as at December 31, 2011 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Collingwood, Ontario
April 30, 2012

Midland Power Utility Corporation
Balance Sheet

December 31	2011	2010
Assets		
Current		
Cash and bank (Note 1)	$ 511,012	$ 177,301
Energy revenue accounts receivable	1,168,527	1,168,187
Other accounts receivable (Note 2)	304,489	311,437
Unbilled energy revenue	2,072,605	2,094,266
Due from shareholder (Note 3)	72,917	81,316
Inventory	31,277	46,043
Prepaid expenses	189,176	200,624
Payments in lieu of corporate taxes receivable	54,855	189,772
	4,404,858	4,268,946
Future income tax asset (Note 4)	459,595	566,645
Property, plant and equipment (Note 5)	10,779,530	10,872,977
Goodwill	1,260,000	1,260,000
Regulatory assets net of regulatory liabilities (Note 6)	707,125	452,554
Long-term investments (Note 7)	100	100
	$ 17,611,208	$ 17,421,222

	2011	2010
Liabilities and Shareholder's Equity		
Current		
Bank indebtedness (Note 8)	$ -	$ 760,000
Accounts payable and accrued liabilities (Note 9)	3,004,792	3,297,885
Due to shareholder (Note 3)	462	5,352
Deferred revenue	40,942	43,609
Current portion of customer deposits	139,115	149,868
Construction deposits	65,786	17,186
Current portion of long-term debt (Note 10)	482,418	1,195,752
	3,733,515	5,469,652
Customer and retailer deposits	198,457	198,477
Long-term debt (Note 10)	3,838,140	2,213,891
Employee future benefits (Note 11)	71,207	74,625
Future income tax liability (Note 4)	213,811	188,792
	8,055,130	8,145,437
Contingencies (Note 12)		
Shareholder's equity		
Share capital (Note 13)	6,880,984	6,880,984
Retained earnings	2,675,094	2,394,801
	9,556,078	9,275,785
	$ 17,611,208	$ 17,421,222

Approved on behalf of the Board:

_______________ Director _______________ Director

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Operations and Retained Earnings

For the year ended December 31	2011	2010 (Note 14)
Energy revenue	$22,294,528	$ 21,214,352
Cost of power	18,857,557	17,858,172
Net distribution revenue	3,436,971	3,356,180
Net service revenue (Note 15)	42,333	35,179
Other net revenue (Note 16)	232,814	250,246
	3,712,118	3,641,605
Expenses		
Administration	797,507	877,919
Amortization	856,005	773,443
Billing and collecting	326,896	330,322
Interest	7,520	9,595
Interest on long-term debt	159,234	89,843
Operations	717,976	670,080
	2,865,138	2,751,202
Income before provision for payments in lieu of corporate income taxes	846,980	890,403
Provision for payments in lieu of corporate income taxes (Note 17)	166,687	85,807
Net income for the year	680,293	804,596
Retained earnings, beginning of year	2,394,801	1,890,205
Dividends (Note 3)	400,000	300,000
Retained earnings, end of year	$ 2,675,094	$ 2,394,801

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

Midland Power Utility Corporation
Statement of Cash Flows

For the year ended December 31	2011	2010
Cash flows from operating activities		
Net income for the year	$ 680,293	$ 804,596
Items not affecting cash:		
Amortization	856,005	773,443
Loss on disposal of property, plant and equipment	2,433	4,384
	1,538,731	1,582,423
Changes in non-cash working capital:		
Energy revenue accounts receivable	(340)	(320,729)
Other accounts receivable	6,948	(235,171)
Unbilled energy revenue	21,661	87,622
Due to/from shareholder	3,509	(52,470)
Inventory	14,766	15,964
Prepaid expenses	11,448	8,008
Accounts payable and accrued liabilities	(293,093)	(317,680)
Payments in lieu of corporate taxes receivable/payable	134,917	(5,756)
Future income taxes	132,069	63,888
Construction deposits	48,600	-
Deferred revenue	(2,667)	43,609
Employee future benefits	(3,418)	(3,440)
	1,613,131	866,268
Cash flows from investing activities		
Expenditures on property, plant and equipment	(767,992)	(2,102,754)
Proceeds on sale of property, plant and equipment	3,000	-
Increase in regulatory assets	(254,570)	(228,698)
	(1,019,562)	(2,331,452)
Cash flows from financing activities		
Customer and retailer deposits (repayments)	(10,773)	19,800
Loan advances	2,200,000	2,135,000
Loan repayments	(1,289,085)	(147,876)
Dividends paid	(400,000)	(300,000)
	500,142	1,706,924
Increase in cash during the year	1,093,711	241,740
Bank indebtedness, beginning of year	(582,699)	(824,439)
Cash (bank indebtedness), end of year	$ 511,012	$ (582,699)
Represented by		
Cash and bank	$ 511,012	$ 177,301
Bank indebtedness	-	(760,000)
	$ 511,012	$ (582,699)

The accompanying summary of significant accounting policies and notes are an integral part of these financial statements.

December 31, 2011

Nature of Business

The corporation was incorporated under the laws of the Province of Ontario on December 22, 1999 in accordance with the provincial government's Electricity Act, 1998. Subsequently, Midland Power Utility Corporation, Mid-Ontario Energy Services Inc. and Community One-Lan Solutions Inc. were amalgamated on May 1, 2002. The newly formed corporation operating as Midland Power Utility Corporation is licensed by the Ontario Energy Board ("OEB") as an electricity distributor. The principal activity of the corporation is to distribute electricity to the Town of Midland. The corporation is regulated by the OEB and adjustments to the distribution and power rates require OEB approval.

Basis of Accounting

The financial statements of Midland Power Utility Corporation are prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) and accounting policies provided by its regulator, the OEB, as contained in the Accounting Procedures Handbook for Electric Distribution Utilities ("AP Handbook"), issued under the authority of the Ontario Energy Board Act, 1998.

Due to the regulatory framework, the timing of recognition of revenues and expenses and the measurement of certain assets and liabilities may differ from that otherwise expected under Canadian generally accepted accounting principles (GAAP) for non-rate regulated enterprises. Please refer to accounting policies for Spare Transformers and Meters, Post 1999 Contributed Capital, Regulatory Assets and Liabilities, and Payments in Lieu of Corporate Income Taxes and Capital Taxes.

The financial statements reflect the significant accounting policies summarized below.

Regulation and Rate Setting

The corporation is required to follow regulations as set by the OEB. The OEB approves and sets rates for the distribution of electricity, ensures distribution companies fulfill their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers.

The OEB sets rates on an annual basis with rates becoming effective on May 1st through April 30th of the following year. The regulation and monitoring of Ontario's Energy Sector is completed by the OEB through application of codes, rules and guidelines, the licensing of market participants, assisting firms with the management of regulatory requirements, monitoring and enforcing compliance and adjudication.

Regulatory Assets and Liabilities

The corporation has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory assets or regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition.

Regulatory assets represent future revenues associated with certain costs, incurred in current or prior period(s), that are expected to be recovered through the rate setting process.

Regulatory liabilities represent future reductions or limitations of revenue increases associated with amounts that are expected to be refunded to customers.

Regulatory assets and liabilities can arise from differences in amounts billed to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred by the corporation in the wholesale market administered by the Independent Electricity System Operator "IESO" after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying the Electricity Act and deferred in anticipation of their future recovery in electricity distribution service charges.

In the absence of rate regulation the regulatory assets and liabilities would be recognized in income in the period to which they relate.

Inventory

Inventory consists of parts and supplies valued at the lower of cost and net realizable value. Cost is generally determined on the first-in, first-out basis.

Seasonality of Operations

The corporation's operations are seasonal. Electricity consumption is typically highest in the summer and winter months, July through September and January through March.

Spare Transformers and Meters

Spare transformers and meters are held to back up plants in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired.

According to the criteria prescribed by the OEB in the AP Handbook the spare transformers and meters are treated as capital assets and included in the distribution systems category. Under Canadian GAAP for unregulated businesses the spare transformers and meters would be treated as inventory.

Post 1999 Contributed Capital

Post 1999 contributed capital consists of third party contributions toward the cost of constructing distribution assets collected after January 1, 2000, and are recorded with property, plant and equipment as a contra account. Contributions are amortized at rates corresponding with the useful lives of the related property, plant and equipment. Canadian GAAP provides no specific guideline on the accounting treatment for this type of contribution.

Post 1999 contributed capital is included in distribution system in the schedule of capital assets.

Long-term Investments

The corporation records its long-term investments using the cost method.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased.

Goodwill is not amortized but is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

Goodwill impairment is assessed based on a comparison for the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill.

When the carrying amount of goodwill exceeds the implied fair value of goodwill an impairment loss is recognized in an amount equal to the excess as a charge against the results of operations.

Management has decided that a valuation was not necessary and therefore impairment of goodwill could not be assessed.

Construction Deposits

Construction deposits represent maintenance deposits and deposits for recoverable work.

Customer Deposits

Customer deposits represent amounts collected from customers to guarantee the payment of energy bills. The customer deposits liability includes interest credited to customers' deposit accounts, with interest expense recorded to offset this amount. Deposits expected to be refunded to customers within one year are classified as a current liability.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, engineering costs, and interest on funds used during construction when applicable. Also included in property, plant and equipment are the costs of capital assets constructed by developers or customers and contributed to the corporation.

Upon disposal the cost and accumulated amortization related to the asset are removed and any gains or losses on disposal are credited or charged to other income on the statement of operations.

Amortization is provided using the following method and annual rates as established by the OEB:

Buildings	20 years	straight-line basis
Distribution system	25 years	straight-line basis
Supervisory equipment	15 years	straight-line basis
Rolling stock	5 - 8 years	straight-line basis
Shop equipment	10 years	straight-line basis
General office equipment	10 years	straight-line basis
Stores equipment	10 years	straight-line basis
Computer equip/software	5 years	straight-line basis
Wireless equipment	10 years	straight-line basis

Spare and replacement parts included in property, plant and equipment are not amortized until they are put into service.

Pension Plan

The corporation offers a pension plan for its full-time employees through the Ontario Municipal Employee Retirement System ("OMERS"). OMERS is a multi-employer, contributory, public sector pension fund established for employees of municipalities, local boards and school boards in Ontario. Participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation accounts for its participation in OMERS as a defined contribution plan and recognizes the expense related to this plan as contributions are made.

Post-employment Benefits

Employee future benefits other than pension provided by the corporation include life insurance premiums paid by the corporation. This plan provides benefits to employees who retired prior to May 2002.

Standards issued by The Canadian Institute of Chartered Accountants with respect to accounting for employee future benefits require the corporation to accrue for its obligations under other employee benefit plans and related costs, net of plan assets.

The cost of post-employment benefits offered to retirees are actuarially determined using the projected benefit method and based on assumptions that reflect management's best estimate.

Revenue Recognition

Revenue from the sale and distribution of electricity is recognized on the accrual basis. The revenue includes cycles billed during the year plus an estimate for unbilled revenue. The unbilled revenue is calculated using real time consumption from the last billing date to December 31, 2011. Actual results could differ from estimates made of electricity usage.

Other revenues, which include revenues from pole attachment, customer demand work, and other miscellaneous revenues are recognized at the time the service is provided.

Payment in Lieu (PIL) of Corporate Income Taxes and Capital Taxes

The corporation is a municipal electricity utility ("MEU") for purposes of the PIL's regime contained in the Electricity Act, 1998. As a MEU the corporation is exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).

Each taxation year, the corporation is required to make payments in lieu of corporate income taxes and capital taxes to Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated based on the rules for computing taxable income and taxable capital outlined in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) taking into account any modifications made by the Electricity Act, 1998, and related regulations.

The corporation provides for payments in lieu of corporate income taxes and capital taxes related to its regulated business using the liability method of accounting.

Use of Estimates and Measurement Uncertainty

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date.

Accounts receivable, unbilled revenue and regulatory assets are reported based on amounts expected to be recovered which reflect an appropriate allowance for unrecoverable amounts. The useful lives of property, plant and equipment have been estimated using rates established by the OEB in order to reflect the appropriate net book values of the assets. Accounts payable and accrued liabilities include some accrual estimates in order to ensure liabilities are complete.

Due to inherent uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the accounting policies.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to regulatory assets and liabilities. The net balance represents future income taxes that flow through the rate-making process.

Continued...

December 31, 2011

Future Income Taxes Continued

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

New Accounting Pronouncements

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International Financial Reporting Standards

On February 13, 2008, the Canadian Accounting Standards Board ["AcSB"] confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. A limited number of converged or IFRS-based standards will be incorporated into Canadian GAAP, with the remaining standards to be adopted at the change over date.

On September 10, 2010, the AcSB granted an optional one year deferral of IFRS adoption to fiscal years beginning on or after January 1, 2012 for entities subject to rate regulation. This decision came in light of the uncertainty created by the International Accounting Standards Board ["IASB"] in regard to the rate-regulated project which is assessing the potential derecognition of regulatory assets and regulatory liabilities under IFRS. Subsequently, the Canadian Securities Administrators announced that entities subject to rate regulation may defer the adoption of IFRS for up to one year, consistent with the one year deferral granted by the AcSB.

On March 21, 2012, the AcSB decided that the mandatory adoption of IFRS for entities subject to rate regulation can be deferred an additional year to fiscal years beginning on or after January 1, 2013.

Continued...

New Accounting Pronouncements continued

Given these recent developments and due to the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated accounting ["RRA"] standard under IFRS and the potential material impact of RRA on the Corporation's financial statements, the Corporation is still considering its options and has not yet decided whether it will adopt IFRS in 2012 or 2013. Accordingly, the Corporation continued to prepare its financial statements in accordance with Canadian GAAP for 2011.

As a result of these developments related to RRA under IFRS and the uncertainty regarding the impact of IFRS on the OEB electricity distribution rates application process, the Corporation cannot reasonably quantify the full impact that adopting IFRS would have on its future financial position and results of operations. During the deferral period, the Corporation has continued to actively monitor IASB developments with respect to RRA and non-RRA IFRS developments and their potential impacts. Prior to the developments noted above, the Corporation's IFRS conversion project was proceeding as planned to meet the January 1, 2012 conversion date.

December 31, 2011

1. Cash and Bank

The corporation's bank accounts are held at one chartered bank. The bank account earns interest at a variable rate.

2. Other Accounts Receivable

	2011	2010
Recoverable work	$ 198,057	$ 53,187
Merchandise and jobbing receivable	14,214	-
Miscellaneous accrued receivables	92,218	26,943
HST receivable	-	231,307
	$ 304,489	$ 311,437

3. Related Party Transactions

The following summarizes the corporation's related party transactions for the year with its shareholder, the Corporation of the Town of Midland:

	2011	2010
Revenue		
- Electricity charges	$ 736,033	$ 708,203
- Maintenance of streetlights and other services	80,704	149,198
Expenses		
- Municipal taxes	38,504	40,685
- Lease fees for substation properties	49,980	49,980
- After hours answering service	20,000	20,000
- Communications antenna	20,000	20,000
- Vehicle servicing, job recoveries and miscellaneous	21,225	9,268
Dividends paid	400,000	300,000

These transactions are in the normal course of operations and are measured at the exchange value (the amount of consideration established and agreed to by the related parties), which approximates the arm's length equivalent value for sales of product or provision of service.

Continued...

3. Related Party Transactions continued

At the end of the year, the amounts due from and (to) its shareholder, the Corporation of the Town of Midland, are as follows:

	2011	2010
Trade receivable, unsecured, due on demand	$ 72,917	$ 81,316
Trade payable, unsecured, due on demand	$ (462)	$ (5,352)

The board of directors approved a $400,000 (2010 - $300,000) dividend that was paid to the Town of Midland. Subsequent to year-end, the board of directors approved and paid a $300,000 dividend for 2012.

The board of directors of Midland Power Utility Corporation received compensation and were reimbursed for certain administrative costs for the year in the amount of $27,402 (2010 - $28,486). These transactions were in the normal course of operations and were measured at the exchange amount.

The corporation paid $20,159 (2010 - $20,755) in fees to Cornerstone Hydro Electric Concepts Association Inc. (CHEC) (See Note 7).

The corporation paid $41,576 (2010 - $43,239) in fees to Utility Collaborative Services Inc. (UCS) for items such as information technology hosting and software licensing (See Note 7).

4. Future Income Taxes

The corporation accounts for the differences between the financial statement carrying value and tax basis of its assets and liabilities following the liability method in accordance with CICA Handbook Section 3465.

Significant components of the corporation's future tax assets (liabilities) are as follows:

	2011	2010
Employee future benefits	$ 13,529	$ 14,925
Property, plant and equipment	446,066	551,720
Long-term future income tax asset	$ 459,595	$ 566,645
Goodwill and land rights	$ (32,758)	$ (22,711)
Regulatory liabilities net of assets	(181,053)	(166,081)
Long-term future income tax liability	$ (213,811)	$ (188,792)
Net future income tax asset	$ 245,784	$ 377,853

The offsetting entry to this net future income tax asset is a credit to regulatory liabilities (See Note 6).

December 31, 2011

5. Property, Plant and Equipment

	2011		2010	
	Cost	Accumulated Amortization	Cost	Accumulated Amortization
Land	$ 381,738	$ -	$ 381,738	$ -
Land rights	32,555	15,060	32,555	15,060
Buildings	1,025,772	444,415	984,361	411,026
Distribution system	18,362,818	9,599,369	17,716,996	8,926,461
Supervisory equipment	562,328	298,397	452,129	270,652
Rolling stock	1,019,207	605,158	1,047,274	527,261
Shop equipment	358,897	291,442	352,201	280,442
General office equipment	260,024	226,029	259,029	228,700
Stores equipment	8,610	8,610	8,610	8,610
Computer equip/software	828,039	711,722	804,662	644,974
Wireless equipment	69,891	69,891	69,891	69,891
Spare and replacement parts	139,744	-	146,608	-
	$23,049,623	$12,270,093	$ 22,256,054	$ 11,383,077
Net book value		$10,779,530		$ 10,872,977

During the year the corporation purchased property, plant and equipment totaling $767,992 (2010 - $2,102,754). Financing of $NIL (2010 - $1,235,000) was used to make the capital purchases and the remainder was paid with cash.

The net book value of stranded meters related to the deployment of smart meters is included in property, plant and equipment in the distribution system category. In the absence of rate regulation, property, plant and equipment would have been decreased to remove the net book value of these stranded meters. The total net book value of all meters included in property, plant and equipment as at December 31, 2011 is $401,364 (2010 - $399,382). The decrease required in the absence of rate regulation is undeterminable as the components of the remaining net book value are not readily determinable.

6. Regulatory Assets and Liabilities

		2011	2010
Net regulatory assets (liabilities) consist of:			
Smart meter initiatives	$	975,789	969,333
Other regulatory assets - Hydro One incremental costs		7,668	7,668
Other regulatory assets - IFRS transition costs		45,166	6,586
Settlement variances		(234,573)	(171,204)
Special purpose charge variance		(389)	35,246
Carrying charges calculated using OEB specified rate		9,265	6,853
Extraordinary event variance		-	228,215
Late payment penalty settlement		-	31,756
Net future income tax liability		(245,784)	(377,853)
Change in income tax rates		(3,728)	(1,239)
Regulatory Asset Recovery Accounts (RARA):			
Disposition of 2005 - 2007 account balances		(4,409)	(57,119)
Disposition of 2008 account balances		(96,095)	(225,688)
Recovery of 2009 account balances		254,215	-
	$	707,125	$ 452,554

Smart Meter Initiatives

The smart meter regulatory asset account relates to the Province of Ontario's decision to install smart meters throughout Ontario by 2010. During 2006 the OEB developed recommendations on smart meters with regard to cost recovery during the phase-in period of this equipment. The OEB stated that given the increased need for electricity and the importance of conservation, specific funding for smart meters could be included in the 2006 rates for all Local Distribution Companies (LDCs). Variance accounts were established to track revenues collected with respect to smart meters and associated costs of the initiatives. The majority of the installation of all smart meters within its service territory was completed in 2009. The OEB approved the request to add a rate rider of $2.00 ($1.00 prior to May 1, 2010) per customer per month to fund Smart Meter activities.

In connection with its smart meter initiatives, the corporation has incurred costs in 2011 amounting to $94,800 (2010 - $308,946). These expenditures would otherwise have been recorded as property, plant and equipment under Canadian GAAP for unregulated businesses. In absence of rate regulation, revenues would have been higher in 2011 by $168,169 (2010 - $132,368), expenses would have been higher in 2011 by $79,825 (2010 - $24,950) and amortization would have been higher in 2011 by $101,997 (2010 - $76,705).

Other Regulatory Assets - Hydro One Incremental Costs

The OEB has approved Other Regulatory Assets, "Sub-account Incremental Capital Charges", for distributors to record the charges arising from the capital rate relief rider. Interest carrying charges, calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates, are applicable for amounts recorded. The new incremental capital charge arises from an incremental capital module approved for Hydro One, which was effective on May 1, 2009 but was implemented on June 1, 2009. In the absence of rate regulation, expenses in 2011 would have been $NIL higher (2010 - $4,007).

Continued...

6. **Regulatory Assets and Liabilities continued**

Other Regulatory Assets - IFRS transition costs

The OEB has approved the collection from customers to cover the expected one-time costs of implementing International Financial Reporting Standards (IFRS). Collections of $25,000 per year for 2009 - 2012 are off-set by OEB approved expenses in this variance account. In the absence of rate regulation, revenues would have been $25,000 higher in 2011 (2010 - $25,000) and expenses would have been $63,580 higher (2010 - $24,436). The deferred balance continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the variance account has not yet been determined by the OEB.

Settlement Variances

Settlement variances represent the differences between amounts charged by the corporation to its customers based on regulated rates and the corresponding cost incurred by the corporation in the wholesale market administered by the IESO. Under the OEB's direction, the corporation has deferred the settlement variances that have occurred since May 1, 2002. Accordingly, the corporation has deferred these recoveries in accordance with the AP Handbook.

Under such regulation, the variances are allowed to be deferred which would be recorded as revenue under Canadian GAAP for unregulated businesses. In the absence of rate regulation, revenues in 2011 would have been $244,860 higher (2010 - $465,657 higher). The deferred balance for unapproved settlement variances continues to be calculated and attract carrying charges in accordance with the OEB's direction. The manner and timing of disposition of the remaining variance has not been determined by the OEB.

Special Purpose Charge Variance

On April 9, 2010, the OEB informed electricity distributors of a Special Purpose Charge ["SPC"] assessment under Section 26.1 of the Ontario Energy Board Act, 1998, for the Ministry of Energy and Infrastructure conservation and renewable energy program costs. The OEB has assessed the corporation $82,891 for its apportioned share of the total provincial amount of the SPC of $53,695,000 in accordance with the rules set out in Ontario Regulation 66/10 [the "SPC Regulation"]. In accordance with Section 9 of the SPC Regulation, the corporation will be allowed to recover this balance. The recovery is to be achieved over a one-year period, starting May 1, 2010.

This variance account relates to the difference between the amount remitted to the Ministry of Finance for LDC's SPC assessment, and the amounts recovered from customers, which commenced on May 1, 2010. Carrying charges apply to the monthly opening balance in the variance account. The SPC Regulation states that the corporation shall apply to the OEB no later than April 15, 2012 for an order authorizing the disposition of any remaining debit or credit balance in the SPC variance account. In the absence of rate regulation, revenue for the year would have been $35,635 higher (2010 - $47,645 higher) and operating expenditures would have been $NIL (2010 - $82,891 higher).

Continued...

6. Regulatory Assets and Liabilities continued

Carrying Charges

Carrying charges are calculated monthly on the opening balance of the applicable variance account using a specific interest rate as outlined by the OEB. In the absence of rate regulation, other revenues would have been higher by $2,507 (2010 - $3,655 lower).

Extraordinary Event Variance

The OEB sets out procedures that LDCs must follow for extraordinary event costs through the Accounting Procedures Handbook ("AP Handbook"). An extraordinary event expense may be considered for recovery if the LDC is able to establish that the expense was clearly outside the base upon which rates were derived, that the expense had a significant influence on the operation of the LDC, that the expense was attributable to an event outside of management's ability to control and that the expense was prudently incurred.

On June 23, 2010 an F2 tornado hit Midland with high winds reaching between 180 kilometers and 240 kilometers an hour as confirmed by Environment Canada. As at December 31, 2010, Midland Power Utility Corporation had incurred costs of $355,873 relating to the repair and replacement of downed power lines and other damage that resulted from the tornado.

Management believes the LDC has met the requirements under the AP Handbook for the extraordinary event costs. The OEB allows LDCs to apply for recovery of expenditures related to the tornado through future rates by way of a rate rider or through the capitalization of costs.

Management and the Board of Directors of Midland Power Utility Corporation have decided not to apply for a rate rider, but to include these costs as capital and recover through regular rates. The capital expenses recorded as a regulatory asset at the end of the prior year were transferred to the appropriate capital accounts in 2011.

Late Payment Penalty Recovered

The late payment penalties settlement account related to the settlement costs accrual associated with a late payment charges class action law suit settled in 2011. The company had accrued a liability and a corresponding regulatory asset in the amount of $31,756 as at December 31, 2010. In 2011, the company paid the liability and is recovering from the rate payers over a one year period from May 1, 2011 to April 30, 2012. As at December 31, 2011, $18,252 has been recovered (Note 16) and a portion of the penalty, prorated monthly, is included in administration expense. In the absence of rate regulation, operating expenses would have been higher by $NIL (2010 - $31,756).

Continued...

6. Regulatory Assets and Liabilities continued

Future Income Tax Regulatory Liability

This regulatory liability account relates to the expected future electricity distribution rate adjustments for customers arising from timing differences in the recognition of future taxes.

On January 1, 2009, the corporation began to account for the differences between its financial statement carrying value and tax basis of assets and liabilities following the liability method in accordance with CICA Handbook Section 3465 (See Note 4).

Change in Income Tax Rates

The OEB has determined that savings arising from the changes in federal and provincial income tax rates should be shared 50/50 with the rate payers. The OEB has determined the amount of savings for 2011 is $2,447 (2010 - $1,231). Carrying charges apply to the monthly opening balance in the variance account. The savings will be reflected in rates when the OEB approves disposition of the variance account.

Regulatory Asset Recovery Accounts (RARA)

The RARA consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through rate riders. The RARA is subject to carrying charges following the OEB prescribed methodology and related rates.

The rate application for 2009, approved by the OEB, included the disposition of regulatory liabilities accumulated from January 1, 2005 - December 31, 2007 plus projected interest up to April 30, 2009. This phase of repayment is for a two year period with rates effective May 1, 2009.

The rate application for 2010, approved by the OEB, included the disposition of regulatory liabilities from January 1, 2008 - December 31, 2008 plus projected interest up to April 30, 2010. This phase of repayment is for a two year period with rates effective May 1, 2010.

The rate application for 2011, approved by the OEB, included the disposition of regulatory liabilities from January 1, 2009 - December 31, 2009 plus projected interest up to April 30, 2011. This phase of repayment is for a two year period with rates effective May 1, 2011.

Fair Value of Regulatory Assets and Regulatory Liabilities

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties related to the ultimate authority of the regulator in determining the asset's treatment for rate setting purposes. Management continually assesses the likelihood of recovery of regulatory assets. If recovery through future rates is no longer considered probable, the amounts would be charged to the results of operations in the period that the assessment is made.

7. Long-term Investments

	2011	2010
Cornerstone Hydro Electric Concepts Association Inc. (CHEC), incorporated without share capital. The cost for the investment was $NIL and therefore not included in these financial statements	$ -	$ -
Utility Collaborative Services Inc. (UCS), recorded using the cost method, 100 common shares, 10% interest	100	100
	$ 100	$ 100

Cornerstone Hydro Electric Concepts Association Inc. (CHEC) is an association of twelve electricity distribution utilities modelled after a cooperative to share resources and proficiencies.

Utility Collaborative Services Inc. (UCS) offers standards-based back office services. The collaboration allows leverage in the reduction of costs for items such as information technology hosting and software licensing.

8. Bank Indebtedness

The corporation has a line of credit with an authorized limit of $4,500,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances is calculated using the bank's prime rate, calculated and payable monthly. It is secured by a general security agreement covering all assets except real property.

As at December 31, 2011 the corporation had drawn a balance of $NIL (2010 - $760,000) on this credit facility. The corporation's line of credit has been pledged as security for the letter of credit provided to the Independent Electricity Systems Operation ("IESO") (see Note 12). As a result, the corporation's access to the $4,500,000 credit facility mentioned above is limited to $3,404,270 (2010 - $2,644,270).

The agreement governing the line of credit facilities contains certain covenants as described in Note 24.

9. Accounts Payable and Accrued Liabilities

	2011	2010
IESO accounts payable	$ 1,423,303	$ 1,517,249
Trade accounts payable	822,542	872,538
Accrued liabilities	506,697	601,197
Customer credit balances	252,250	306,901
	$ 3,004,792	$ 3,297,885

Included in trade accounts payable is one (2010 - three) customer(s) who represent(s) 58% (2010 - 70%) of the total balance. Included in accrued liabilities is one (2010 - two) customer(s) who represent(s) 58% (2010 - 67%) of the total balance.

December 31, 2011

10. Long-term Debt

	2011	2010
Infrastructure Ontario Debenture - 4.12% fixed rate, $33,333 principal repayable semi-annually plus interest on December 15th and June 15th, secured by a general security agreement covering a second charge on all assets and real property, due June 15, 2026	$ 966,667	$ 900,000
Infrastructure Ontario Debenture - 2.91% fixed rate, $30,000 principal repayable semi-annually plus interest on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2015	210,000	270,000
Infrastructure Ontario Debenture - 3.91% fixed rate, $56,126 principal repayable semi-annually plus interest, on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2020	954,141	1,066,393
Infrastructure Ontario Debenture - 3.91% fixed rate, $61,750 principal repayable semi-annually plus interest, on October 1st and April 1st, secured by a general security agreement covering a second charge on all assets and real property, due April 1, 2020	1,049,750	1,173,250
Infrastructure Ontario Debenture - 4.00% fixed rate, $60,000 principal repayable semi-annually plus interest, on September 1st and March 1st, secured by a general security agreement covering a second charge on all assets and real property, due March 1, 2021	1,140,000	-
	4,320,558	3,409,643
Current portion of long-term debt	482,418	1,195,752
	$ 3,838,140	$ 2,213,891

Total construction advances of $5.5 million have been approved by Infrastructure Ontario. At December 31, 2011, the corporation had undrawn credit capacity under this facility of approximately $642,481.

The agreement governing these credit facilities contains certain covenants as described in Note 24.

Continued...

10. Long-term Debt continued

Principal repayments for each of the five subsequent years and thereafter are as follows:

2012	$ 482,418
2013	482,418
2014	482,418
2015	452,418
2016	422,418
Thereafter	1,998,468
	$ 4,320,558

11. Employee Future Benefits

During 2003 the corporation discontinued its post-retirement life insurance, dental and health benefits to all employees. As at December 31, 2011, there are only six (2010 - six) retirees who retain the post-retirement life insurance benefit. Information about the post-retirement life insurance benefit plan is as follows:

	2011	2010
Accrued benefit liability, beginning of year	$ 74,625	$ 78,065
Expense for the year	(3,418)	(3,440)
Projected accrued benefit obligation at December 31	$ 71,207	$ 74,625

An actuarial report was performed and dated January 20, 2010. The actuarial valuation was performed on the post-retirement obligations sponsored by the corporation as at December 31, 2009. The next actuarial valuation will be performed December 31, 2012.

The main actuarial assumptions employed for the valuations are as follows:

(a) General inflation: Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% per annum.

(b) Interest (discount) rate: The obligation, as at December 31, 2011, of the present value of future liabilities was determined using an annual discount rate of 6.0%. This rate reflects the assumed long-term yield on high quality bonds.

(c) Expenses: The assumption was made that 10% of benefits are required for the cost of sponsoring the program for life insurance.

(d) Change in Post-Retirement Plan: The accrued benefit obligation was decreased in 2009 over the 2006 valuation mainly as a result of a higher discount rate assumption and the death of one retiree.

12. Contingencies

The corporation is contingently liable as a guarantor for a letter of credit for $1,095,730 with its bank provided to the Independent Electricity Systems Operator (IESO) to secure the corporation's hydro purchase obligations.

13. Share Capital

The authorized share capital of the corporation is an unlimited number of common and preference shares. The issued share capital is as follows:

	2011	2010
1,000 Common shares	$ 6,880,984	$ 6,880,984

14. Prior Period Adjustment

In the prior period, energy revenue and cost of power were recorded at the higher of the revenue billed and expenses charged. The OEB requires that these amounts be recorded at the lesser amount. An entry has been recorded to correct this in the prior period, decreasing energy revenue and decreasing cost of power by $315,607 each. The net effect on net income and retained earnings is $NIL.

15. Net Service Revenue

	2011	2010
Service revenue	$ 138,638	$ 135,649
Service costs	(96,305)	(100,470)
Net service revenue	$ 42,333	$ 35,179

16. Other Net Revenue

		2011		2010
(Carrying charges) income on regulatory balances	$	(2,508)	$	3,655
Loss on disposal		(2,433)		(2,543)
Interest earned		7,038		3,362
Late payment charges		22,518		19,795
Ontario Power Authority management fees		-		34,246
Office rental		48,834		50,940
Other		109,309		108,837
Pole rental		31,804		31,954
Late payment penalty settlement (Note 6)		18,252		-
	$	232,814	$	250,246

17. Payments in Lieu of Corporate Income Taxes

		2011		2010
Income before provision for PILs	$	846,980	$	890,403
Statutory Canadian federal and provincial tax rate		28.00%		30.00%
Provision for PILs at statutory rate		237,154		267,121
Small business deduction		(40,589)		(64,998)
Cumulative eligible capital deduction		(16,480)		(18,986)
Net increase in regulatory assets		(18,509)		(37,295)
Changes to statutory tax rate		1,177		5,171
Amortization expense in excess of capital cost allowance		(70,177)		(54,174)
Change in pension post retirement plan (not taxable)		(957)		(1,032)
Other items		868		763
Coop tax credit		(1,944)		-
Corporate minimum tax		-		(11,994)
Adjustment to tax provision		76,144		1,231
Total provision	$	166,687	$	85,807
Effective tax rate		19.68%		9.64%

18. Statement of Cash Flows

	2011	2010
Interest paid	$ 138,025	$ 66,052
Interest received	$ 7,038	$ 3,362
PILs paid	$ 214,007	$ 90,332
PILs received	$ 184,352	$ -

19. Liability Insurance

The corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members.

20. Scientific Research and Experimental Development Claim

The corporation signed a contract with BeneFACT Consulting Group for submission of a Scientific Research and Experimental Development claim in 2011 for the 2010 and 2011 taxation years. The 2010 claim was filed in January 2012 resulting in a contingent gain of $92,077. The 2011 claim was filed in April 2012 resulting in a contingent gain of $76,866. These gains will be reduced by fees to be paid contingently to BeneFACT at 20% on the first $150,000 of credit and 15% thereafter. These claims have not yet been assessed by CRA and could be adjusted or denied.

21. Subsequent Event

Midland Power Utility Corporation has filed an evidence package to support the disposition of the 1562 Deferred PILS Regulatory Asset account as part of their 2012 Incentive Regulation Mechanism (IRM) rate application for rates effective May 1, 2012. This disposition is in response to the SIMPILS True-Up Models for the years 2001 to 2005. The PILS included in rates were based on proxies for what the actual tax rates would be. The true-up process for the above noted years captures the difference between the rates used to determine the PILs proxies and one of: minimum tax rates; maximum tax rates; or, effective tax rates in the actual year, taking into consideration the Corporation's actual taxable capital in each of the years. Midland Power Utility Corporation has applied to the Ontario Energy Board with a credit balance (owed to customers) of $205,700 based on effective tax rates. This amount would be offset against income over a two year term as it is paid to the rate payers. The company believes this is the likely minimum amount owing.

December 31, 2011

22. Financial Instruments

All financial instruments are included on the balance sheet and are measured either at fair market value or, in limited circumstances, at cost or amortized cost. The corporation classifies its financial instruments into one of the following categories:

Held-for-trading
Held-for-trading is comprised of cash and bank. This instrument is carried in the balance sheet at fair value with changes in fair value recognized in the income statement. Transaction costs related to instruments classified as held-for-trading are expensed as incurred.

Loans and receivables
Loans and receivables are comprised of accounts receivable and unbilled revenue. They are initially recognized at fair value and subsequently carried at amortized cost, using the effective interest rate method, less any provision for impairment. Transaction costs related to loans and receivables are expensed as incurred.

Other financial liabilities
Other financial liabilities are comprised of bank indebtedness, accounts payable and accrued liabilities, customer and construction deposits, amounts due to shareholder, and long-term debt. These liabilities are initially recognized at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs related to other financial liabilities are netted against the amount initially recognized.

The Corporation's carrying value and fair value of financial instruments consist of the following:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Assets				
Cash and bank	**511,012**	**511,012**	177,301	177,301
Accounts receivable	**3,545,621**	**3,545,621**	3,573,889	3,573,889
Long-term investments	**100**	**undeterminable**	100	undeterminable
Due from shareholder	**72,917**	**72,917**	81,316	81,316
Liabilities				
Bank indebtedness	**-**	**-**	760,000	760,000
Accounts payable	**3,004,792**	**3,004,792**	3,297,885	3,297,885
Due to shareholder	**462**	**462**	5,352	5,352
Customer deposits	**337,572**	**337,572**	348,345	348,345
Construction deposits	**65,786**	**65,786**	17,186	17,186
Long-term debt	**4,320,558**	**4,630,859**	3,409,643	3,409,643

Continued...

22. Financial Instruments continued

The estimated fair values of financial instruments as at December 31, 2011 and December 31, 2010 are based on relevant market prices and information available at the time. The fair value estimates are not necessarily indicative of the amounts that the corporation may receive or incur in actual market transactions. These estimates are subjective in nature and involve uncertainties and matters of significant judgment and therefore cannot be determined with precision. Changes in assumptions could significantly affect the estimates.

Determination of fair values

(a) The fair values of cash and bank, accounts receivable, unbilled revenue, current customer deposits, accounts payable and accrued liabilities and bank indebtedness approximate their carrying values because of the short maturity of these instruments.

(b) Long-term investments include common shares of private companies accounted for by the cost method. These investments are not publicly traded and, therefore, fair values are not practicable to determine.

(c) The fair value of each of the corporation's long-term debt instruments is based on the amount of future cash flows associated with each instrument discounted using an estimate of what the corporation's current borrowing rate for similar debt instruments of comparable maturity would be.

It is management's intention not to renew the long-term debt until its maturity.

23. Pension Agreements

The corporation makes contributions to the Ontario Municipal Employee Retirement System (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The Administration Corporation Board of Directors, representing plan members and employers, is responsible for overseeing the management of the pension plan, including investment of the assets and administration of the benefits. OMERS provides pension services to more than 419,000 active and retired members and approximately 947 employers. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

Each year, an independent actuary determines the funding status of OMERS Primary Pension Plan (the Plan) by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2011. The results of this valuation disclosed total actuarial liabilities of $64,548 (2010 - $60,035) million in respect of benefits accrued for service with actuarial assets at that date of $57,258 (2010 - $55,568) million, indicating an actuarial deficit of $7,290 (2010 - $4,467) million. Because OMERS is a multi-employer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees. As a result, the corporation does not recognize any share of the OMERS pension surplus or deficit.

The contribution rates for the plan were 7.4% (2010 - 6.4%) for employees earning up to $48,300 (2010 - 47,200) and 10.7% (2010 - 9.7%) thereafter. The amount contributed to OMERS for 2011 was $161,580 (2010 - $125,934).

24. Capital Disclosures

The corporation considers its capital to be its share capital and retained earnings. The corporation's main objectives when managing capital are to: i) ensure sufficient liquidity to support its financial obligations and execute its operating and strategic plans, ii) minimize the cost of capital while taking into consideration current and future industry, market and economic risks and conditions, iii) maintain an optimal capital structure that provides necessary financial flexibility while also ensuring compliance with any financial covenants, and iv) provide an adequate return to its shareholder.

The corporation relies predominately on its cash flow from operations to fund its dividend distributions to its shareholder. This cash flow is supplemented, when necessary, through the borrowing of additional debt.

As part of existing debt agreements, financial covenants are monitored and communicated, as required by the terms of credit agreements, on an annual basis by management to ensure compliance with the agreements.

The bank indebtedness covenants require the corporation to maintain a minimum Interest Coverage Ratio of 2.5 times and to maintain a maximum Total Debt to Capitalization of 0.60 to 1. The corporation was in compliance with these covenants as at December 31, 2011.

The Infrastructure Ontario loan covenants require the corporation to provide notification prior to any new debt issuance and to seek approval where the Debt Service Coverage Ratio falls below 1 to 1 at any time; such ratio is otherwise tested and calculated as of the end of each fiscal year. The corporation is also required to maintain a maximum Debt to Capital ratio of 0.60 to 1 and a minimum current ratio of 1.1 to 1 to be tested and calculated as of the end of each fiscal year. The corporation is in compliance with these covenants as at December 31, 2011.

Management monitors the following key ratios to effectively manage capital:

	2011	2010
a) Debt Service Coverage Ratio:	1.22:1	1.48:1
b) Debt to Capital:	0.34:1	0.34:1
c) Current ratio:	1.18:1	0.78:1

25. Financial Risk Management

As part of its operations, the corporation carries out transactions that expose it to financial risks such as credit, liquidity and market risks.

The following is a discussion of risks and related mitigation strategies that have been identified by the company for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.

Credit risk

Credit risk is the risk that one party to a financial instrument might not meet its obligations under the terms of the financial instrument. The maximum credit exposure is limited to the carrying amount of cash and receivables presented on the balance sheet.

Financial instruments that potentially subject the corporation to a significant concentration of credit risk consist primarily of cash. The corporation limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The corporation maintains cash with one major financial institution. Eligible deposits are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation.

The corporation is exposed to credit risk related to accounts receivable arising from its day-to-day electricity and service revenue. Exposure to credit risk from accounts receivable is limited due to the corporation's large and diverse customer base. Moreover, the corporation holds as collateral customer and construction deposits, which are recognized as liabilities on the balance sheet. The Ontario Energy Board has prescribed certain rules for the payment of deposits by customers. Although these rules limit the risk of the company, no deposits are required by customers who have shown good payment history for the previous 24 month period. The company does not have any material accounts receivable balances greater than 90 days outstanding. As a result, the company believes that its accounts receivable represent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the income statement. The provision is based on account age and customer standing. Subsequent recoveries of receivables previously provisioned are credited to the income statement.

The company's accounts receivable are not subject to a significant concentration of credit risk because they are distributed over a large customer base.

The value of accounts receivable, by age, and the related bad debt provision are presented in the following table. The accounts receivable balance consists of energy, other and unbilled revenue receivables.

Unbilled revenue represents amounts to which the corporation has a contractual right to receive cash through future billings but are unbilled at period-end. Unbilled revenue outstanding is considered current.

Continued...

December 31, 2011

25. Financial Risk Management continued

Accounts Receivable

	2011	2010
Under 30 days	$ 3,445,012	$ 3,518,396
30 to 60 days	94,410	45,203
61 to 90 days	16,017	66,895
Over 90 days	143,099	218,714
	3,698,538	3,849,208
Provision	80,000	194,002
Total accounts receivable	$ 3,618,538	$ 3,655,206
Represented by:		
Due from shareholder	$ 72,917	$ 81,316
Energy revenue accounts receivable	1,168,527	1,168,187
Other accounts receivable	304,489	311,437
Unbilled energy revenue	2,072,605	2,094,266
	$ 3,618,538	$ 3,655,206

Liquidity risk

Liquidity risk is the risk that the corporation will encounter difficulty in meeting obligations associated with financial liabilities. The corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the corporation's reputation. The corporation's exposure is reduced by cash generated from operations and their undrawn credit facility. The corporation engages in borrowing to meet financing needs that exceed cash from operations. Exposure to such risks is significantly reduced through close monitoring of cash flows and budgeting.

Liquidity risks associated with financial commitments are as follows:

	0 - 3 mo	3 mo - 1 yr	1 - 5 yr	Termless
Bank indebtedness	$ -	$ -	$ -	$ -
Accounts payable and accrued liabilities	3,004,792	-	-	-
Construction loan	60,000	422,418	1,839,672	-
Due to shareholder	462	-	-	-
Customer deposits	-	139,115	198,457	-
Deferred revenue	10,235	30,706	-	-
Construction deposits	-	65,786	-	-
Employee future benefits	-	3,417	13,668	54,122
Total	$ 3,075,489	$ 661,442	$ 2,051,797	$ 54,122

Continued...

25. Financial Risk Management continued

Market risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the corporation's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits.

The corporation does not have any direct exposure to foreign currency exchange rate risk or commodity price risk. The corporation had no forward exchange rate contracts or commodity price contracts in place as at or during the year ended December 31, 2011.

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The corporation is exposed to interest rate fluctuations on its cash and bank, undrawn credit facilities and Infrastructure Ontario construction loan which bear a floating rate of interest. The corporation's exposure to interest rate risk is limited by cash from operations making it possible to maintain a high interest coverage ratio. As at December 31, 2011, if interest rates had been 1% lower or higher with all other variables held constant, net income for the year would not have been impacted materially.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

The only reconciliation required between financial statements and regulatory accounting relate to those expenses which the OEB has disallowed for rate application purposes. These have identified in the table below. These expenses have been removed from requested OM&A expenses for 2013 Test Year in Exhibit 4 of this application.

Table 4.2.1 – Reconciliation from Audited OM&A Expense to Regulatory OM&A Expense

		2009		2010		2011
OM&A per Audited Financial Statements	$	1,819,996	$	1,878,321	$	1,842,379
Less:						
Charitable Donations	$	360	$	354	$	62
Penalties	$	9	$	52	$	21,839
Property Taxes	$	31,052	$	30,058	$	28,676
OM&A Expense	$	1,788,575	$	1,847,857	$	1,791,803

PRO FORMA FINANCIAL STATEMENTS - 2012 AND 2013:

The Pro Forma Statements for the 2012 Bridge Year and the 2013 Test Year accompany this Schedule as Appendix E and Appendix F respectively.

APPENDIX E

COPY OF MIDLAND POWER UTILITY CORPORATION

2012 PRO FORMA FINANCIAL STATEMENTS - (CGAAP) AND (MIFRS)

2012 PRO FORMA FINANCIAL STATEMENTS - (CGAAP)

2012 BALANCE SHEET (CGAAP)

Account Description	Total
1050-Current Assets	
1005-Cash	(1,306,943)
1010-Cash Advances and Working Funds	6,300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	100
1100-Customer Accounts Receivable	1,269,458
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	270,974
1105-Accounts Receivable - Merchandise, Jobbing, etc.	14,214
1110-Other Accounts Receivable	92,218
1120-Accrued Utility Revenues	2,072,605
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(80,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	189,176
1190-Miscellaneous Current and Accrued Assets	85,778
1200-Accounts Receivable from Associated Companies	0
1220-MPMARebate	0
1050-Current Assets Total	**2,613,879**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	163,729
1340-Merchandise	0
1350-Other Material and Supplies	7,292
1100-Inventory Total	**171,021**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,260,000
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,260,000**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	53,306
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(23,053)
1525-Miscellaneous Deferred Debits	(25)
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	0
1550-LV Charges - Variance	(61,129)
1555-Smart Meters Recovery	690,188
1556-Smart Meters OM & A	307,298
1562-Deferred PILs	(458,920)
1563-Deferred PILs - Contra	458,920
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(465,329)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	64,319
1586-RSVA - Connection Charges	(18,870)
1588-RSVA - Commodity (Power)	170,443
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	149,983
1200-Other Assets and Deferred Charges Total	**867,130**

1450-Distribution Plant	
1612-Land Rights (Formally known as Account 1906)	32,555
1805-Land	381,738
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,604,933
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	4,907,335
1835-Overhead Conductors and Devices	2,288,831
1840-Underground Conduit	1,948,941
1845-Underground Conductors and Devices	1,772,824
1850-Line Transformers	3,726,953
1855-Services	338,323
1860-Meters	1,117,459
1860-Meters (Smart Meters)	1,204,471
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**23,324,362**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	1,070,772
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	260,024
1920-Computer Equipment - Hardware	494,483
1920-Computer Equipment - Hardware (Smart Meters)	18,764
1925-Computer Software	373,256
1925-Computer Software (Smart Meters)	68,016
1930-Transportation Equipment - Large Vehicles	1,011,195
1930-Transportation Equipment - Small Vehicles	171,823
1935-Stores Equipment	8,610
1940-Tools, Shop and Garage Equipment	289,725
1945-Measurement and Testing Equipment	2,634
1950-Power Operated Equipment	0
1955-Communication Equipment	134,110
1960-Miscellaneous Equipment	19,220
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	562,328
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(2,130,721)
1500-General Plant Total	**2,354,239**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(13,196,172)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(13,196,172)**

Total Assets	**17,394,458**

1650-Current Liabilities	
2205-Accounts Payable	593,202
2208-Customer Credit Balances	252,250
2210-Current Portion of Customer Deposits	204,901
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	561,873
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	110,344
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	1,423,303
2260-Current Portion of Long Term Debt	482,418
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	45,724
2292-Payroll Deductions / Expenses Payable	12,846
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**3,686,861**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	71,207
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	5,621
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	198,457
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
-Other Liabilities and Deferred Credits	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	(13,913)
1700-Non-Current Liabilities Total	**261,371**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	3,838,140
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	0
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**3,838,140**

1850-Shareholders' Equity	
3005-Common Shares Issued	6,880,984
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	2,675,093
3046-Balance Transferred From Income	352,008
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	(300,000)
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**9,608,085**

Total Liabilities & Shareholder's Equity	**17,394,458**

Balance Sheet Total	0

2012 STATEMENT OF INCOME AND RETAINED EARNINGS (CGAAP)

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(4,141,303)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(113,929)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(12,580,674)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,335,134)
4064-Billed WMS-One Time	0
4066-NS	(1,100,356)
4068-CS	(887,627)
4075-LV Charges	(268,554)
3000-Sales of Electricity Total	**(20,427,576)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(3,624,391)
4080-2-SSS Revenue	(19,500)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(3,643,891)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(77,300)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	(5,600)
4225-Late Payment Charges	(23,400)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(122,100)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(228,400)**

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(92,500)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	63,000
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4357-Gain from Retirement of Utility and Other Property	(26,855)
4362-Loss from Retirement of Utility and Other Property	0
4375-Revenues from Non-Utility Operations	(57,600)
4380-Expenses of Non-Utility Operations	36,800
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(77,155)**
3200-Investment Income	
4405-Interest and Dividend Income	0
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**0**
3350-Power Supply Expenses	
4705-Power Purchased	16,835,905
4708-WMS	1,102,016
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	1,100,356
4715-System Control and Load Dispatching	0
4716-NCN	887,627
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	233,119
4750-LV Charges	268,554
3350-Power Supply Expenses Total	**20,427,576**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	277,900
5010-Load Dispatching	4,000
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	3,981
5017-Distribution Station Equipment - Operation Supplies and Expenses	15,900
5020-Overhead Distribution Lines and Feeders - Operation Labour	0
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	0
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	1,800
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	4,748
5070-Customer Premises - Operation Labour	38,815
5075-Customer Premises - Materials and Expenses	2,454
5085-Miscellaneous Distribution Expense	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**349,599**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	91,825
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	83,969
5120-Maintenance of Poles, Towers and Fixtures	16,769
5125-Maintenance of Overhead Conductors and Devices	75,152
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	25,706
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	64,913
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	6,239
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	92,816
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**457,389**

3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	172,886
5315-Customer Billing	202,600
5320-Collecting	78,200
5325-Collecting - Cash Over and Short	100
5330-Collection Charges	900
5335-Bad Debt Expense	25,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**479,686**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	3,527
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**3,527**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,500
5610-Management Salaries and Expenses	373,900
5615-General Administrative Salaries and Expenses	60,658
5620-Office Supplies and Expenses	108,200
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	49,500
5635-Property Insurance	26,700
5640-Injuries and Damages	15,800
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	95,182
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	46,200
5670-Rent	0
5675-Maintenance of General Plant	121,459
5680-Electrical Safety Authority Fees	5,100
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**930,199**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	937,061
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**937,061**
3900-Interest Expense	
6005-Interest on Long Term Debt	394,082
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	0
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**394,082**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	29,500
3950-Taxes Other Than Income Taxes Total	**29,500**
4000-Income Taxes	
6110-Income Taxes	5,696
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**5,696**
4100-Extraordinary & Other Items	
6205-Donations	100
6210-Life Insurance	0
6215-Penalties	10,600
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**10,700**
Net Income - (Gain)/Loss	**(352,008)**

2012 BALANCE SHEET - MIFRS

Account Description	Total
1050-Current Assets	
1005-Cash	(1,309,581)
1010-Cash Advances and Working Funds	6,300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	100
1100-Customer Accounts Receivable	1,269,458
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	270,974
1105-Accounts Receivable - Merchandise, Jobbing, etc.	14,214
1110-Other Accounts Receivable	92,218
1120-Accrued Utility Revenues	2,072,605
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(80,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	189,176
1190-Miscellaneous Current and Accrued Assets	85,778
1200-Accounts Receivable from Associated Companies	0
1220-MPMARebate	0
1050-Current Assets Total	**2,611,241**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	163,729
1340-Merchandise	0
1350-Other Material and Supplies	7,292
1100-Inventory Total	**171,021**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,260,000
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,260,000**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	53,306
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(23,053)
1525-Miscellaneous Deferred Debits	(25)
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	0
1550-LV Charges - Variance	(61,129)
1555-Smart Meters Recovery	690,188
1556-Smart Meters OM & A	307,298
1562-Deferred PILs	(458,920)
1563-Deferred PILs - Contra	458,920
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(465,329)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	64,319
1586-RSVA - Connection Charges	(18,870)
1588-RSVA - Commodity (Power)	170,443
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	149,983
1200-Other Assets and Deferred Charges Total	**867,130**

1450-Distribution Plant	
1612-Land Rights (Formally known as Account 1906)	32,555
1805-Land	381,738
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	5,412,282
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	4,792,795
1835-Overhead Conductors and Devices	2,236,788
1840-Underground Conduit	1,948,941
1845-Underground Conductors and Devices	1,772,824
1850-Line Transformers	3,672,084
1855-Services	338,323
1860-Meters	1,117,459
1860-Meters (Smart Meters)	1,204,471
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**22,910,259**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	1,070,772
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	260,024
1920-Computer Equipment - Hardware	494,483
1920-Computer Equipment - Hardware (Smart Meters)	18,764
1925-Computer Software	373,256
1925-Computer Software (Smart Meters)	68,016
1930-Transportation Equipment - Large Vehicles	1,011,195
1930-Transportation Equipment - Small Vehicles	171,823
1935-Stores Equipment	8,610
1940-Tools, Shop and Garage Equipment	289,725
1945-Measurement and Testing Equipment	2,634
1950-Power Operated Equipment	0
1955-Communication Equipment	134,110
1960-Miscellaneous Equipment	19,220
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	562,328
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(2,166,197)
1500-General Plant Total	**2,318,763**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(12,511,128)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(12,511,128)**

Total Assets	**17,627,286**

1650-Current Liabilities	
2205-Accounts Payable	593,202
2208-Customer Credit Balances	252,250
2210-Current Portion of Customer Deposits	204,901
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	561,873
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	110,344
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	1,423,303
2260-Current Portion of Long Term Debt	482,418
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	45,724
2292-Payroll Deductions / Expenses Payable	12,846
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**3,686,861**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	71,207
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	5,621
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	198,457
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
-Other Liabilities and Deferred Credits	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	(13,913)
1700-Non-Current Liabilities Total	**261,371**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	3,838,140
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	0
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**3,838,140**

1850-Shareholders' Equity	
3005-Common Shares Issued	6,880,984
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	2,675,093
3046-Balance Transferred From Income	584,835
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	(300,000)
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**9,840,912**

Total Liabilities & Shareholder's Equity	**17,627,285**

Balance Sheet Total	0

2012 STATEMENT OF INCOME AND RETAINED EARNINGS (MIFRS)

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(4,141,303)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(113,929)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(12,580,674)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,335,134)
4064-Billed WMS-One Time	0
4066-NS	(1,100,356)
4068-CS	(887,627)
4075-LV Charges	(268,554)
3000-Sales of Electricity Total	**(20,427,576)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(3,624,391)
4080-2-SSS Revenue	(19,500)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(3,643,891)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(77,300)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	(5,600)
4225-Late Payment Charges	(23,400)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(122,100)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(228,400)**

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(92,500)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	63,000
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4357-Gain from Retirement of Utility and Other Property	(26,855)
4362-Loss from Retirement of Utility and Other Property	75,569
4375-Revenues from Non-Utility Operations	(57,600)
4380-Expenses of Non-Utility Operations	36,800
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(1,586)**
3200-Investment Income	
4405-Interest and Dividend Income	0
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**0**
3350-Power Supply Expenses	
4705-Power Purchased	16,835,905
4708-WMS	1,102,016
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	1,100,356
4715-System Control and Load Dispatching	0
4716-NCN	887,627
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	233,119
4750-LV Charges	268,554
3350-Power Supply Expenses Total	**20,427,576**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	277,900
5010-Load Dispatching	4,000
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	3,981
5017-Distribution Station Equipment - Operation Supplies and Expenses	15,900
5020-Overhead Distribution Lines and Feeders - Operation Labour	0
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	0
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	1,800
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	4,748
5070-Customer Premises - Operation Labour	38,815
5075-Customer Premises - Materials and Expenses	2,454
5085-Miscellaneous Distribution Expense	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**349,599**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	91,825
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	83,969
5120-Maintenance of Poles, Towers and Fixtures	16,769
5125-Maintenance of Overhead Conductors and Devices	75,152
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	25,706
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	64,913
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	6,239
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	92,816
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**457,389**

3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	172,886
5315-Customer Billing	202,600
5320-Collecting	78,200
5325-Collecting - Cash Over and Short	100
5330-Collection Charges	900
5335-Bad Debt Expense	25,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**479,686**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	3,527
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**3,527**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,500
5610-Management Salaries and Expenses	373,900
5615-General Administrative Salaries and Expenses	60,658
5620-Office Supplies and Expenses	108,200
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	49,500
5635-Property Insurance	26,700
5640-Injuries and Damages	15,800
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	95,182
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	46,200
5670-Rent	0
5675-Maintenance of General Plant	121,459
5680-Electrical Safety Authority Fees	5,100
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**930,199**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	626,027
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**626,027**
3900-Interest Expense	
6005-Interest on Long Term Debt	397,204
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	0
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**397,204**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	29,500
3950-Taxes Other Than Income Taxes Total	**29,500**
4000-Income Taxes	
6110-Income Taxes	5,212
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**5,212**
4100-Extraordinary & Other Items	
6205-Donations	100
6210-Life Insurance	0
6215-Penalties	10,600
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**10,700**
Net Income - (Gain)/Loss	**(584,835)**

APPENDIX F

COPY OF MIDLAND POWER UTILITY CORPORATION

2013 PRO FORMA STATEMENTS – MIFRS (Existing Rates)

2013 BALANCE SHEET - MIFRS

Account Description	Total
1050-Current Assets	
1005-Cash	(2,085,725)
1010-Cash Advances and Working Funds	6,300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	100
1100-Customer Accounts Receivable	1,269,458
1102-Accounts Receivable - Services	0
1104-Accounts Receivable - Recoverable Work	270,974
1105-Accounts Receivable - Merchandise, Jobbing, etc.	14,214
1110-Other Accounts Receivable	92,218
1120-Accrued Utility Revenues	2,072,605
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(80,000)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	189,176
1190-Miscellaneous Current and Accrued Assets	85,778
1200-Accounts Receivable from Associated Companies	0
1220-MPMARebate	0
1050-Current Assets Total	**1,835,097**

Account Description	Total
1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	163,729
1340-Merchandise	0
1350-Other Material and Supplies	7,292
1100-Inventory Total	**171,021**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	1,260,000
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**1,260,000**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	53,306
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(23,053)
1525-Miscellaneous Deferred Debits	(25)
1530-Deferred Losses from Disposition of Utility Plant	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	0
1550-LV Charges - Variance	(61,129)
1555-Smart Meters Recovery	690,188
1556-Smart Meters OM & A	307,298
1562-Deferred PILs	(458,920)
1563-Deferred PILs - Contra	458,920
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1580-RSVA - Wholesale Market Services	(465,329)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	64,319
1586-RSVA - Connection Charges	(18,870)
1588-RSVA - Commodity (Power)	170,443
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	149,983
1200-Other Assets and Deferred Charges Total	**867,130**

1450-Distribution Plant	
1612 - Land Rights (Formerly known as Account #1906)	32,555
1805-Land	381,738
1806-Land Rights	0
1808-Buildings and Fixtures	0
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	6,187,115
1825-Storage Battery Equipment	0
1830-Poles, Towers and Fixtures	5,004,341
1835-Overhead Conductors and Devices	2,307,917
1840-Underground Conduit	1,948,941
1845-Underground Conductors and Devices	2,160,324
1850-Line Transformers	3,948,974
1855-Services	369,223
1860-Meters	326,357
1860-Meters (Smart Meters)	1,204,471
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**23,871,955**

1500-General Plant	
1905-Land	0
1906-Land Rights	0
1908-Buildings and Fixtures	1,095,772
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	260,024
1920-Computer Equipment - Hardware	516,683
1920-Computer Equipment - Hardware (Smart Meters)	18,764
1925-Computer Software	428,256
1925-Computer Software (Smart Meters)	68,016
1930-Transportation Equipment - Large Vehicles	1,011,195
1930-Transportation Equipment - Small Vehicles	171,823
1935-Stores Equipment	8,610
1940-Tools, Shop and Garage Equipment	299,725
1945-Measurement and Testing Equipment	2,634
1950-Power Operated Equipment	0
1955-Communication Equipment	134,110
1960-Miscellaneous Equipment	19,220
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	737,328
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	(2,690,085)
1500-General Plant Total	**2,082,074**

1550-Other Capital Assets	
2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(12,403,029)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(12,403,029)**

Total Assets	**17,684,248**

1650-Current Liabilities	
2205-Accounts Payable	593,202
2208-Customer Credit Balances	252,250
2210-Current Portion of Customer Deposits	204,901
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	561,873
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	0
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	110,344
2252-Transmission Charges Payable	0
2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	1,423,303
2260-Current Portion of Long Term Debt	482,418
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	0
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	45,724
2292-Payroll Deductions / Expenses Payable	12,846
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	0
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**3,686,861**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	71,207
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	5,621
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	198,457
2340-Collateral Funds Liability	0
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	0
-Other Liabilities and Deferred Credits	0
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	(13,913)
1700-Non-Current Liabilities Total	**261,371**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	3,838,140
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	0
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	0
1800-Long-Term Debt Total	**3,838,140**

1850-Shareholders' Equity	
3005-Common Shares Issued	6,880,984
3008-Preference Shares Issued	0
3010-Contributed Surplus	0
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	2,959,928
3046-Balance Transferred From Income	356,962
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	(300,000)
3049-Dividends Payable-Common Shares	0
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**9,897,874**

Total Liabilities & Shareholder's Equity	**17,684,247**

Balance Sheet Total	0

2013 STATEMENT OF INCOME AND RETAINED EARNINGS - MIFRS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(4,210,331)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	0
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(110,617)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(11,951,248)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	0
4060-Interdepartmental Energy Sales	0
4062-WMS	(1,362,119)
4064-Billed WMS-One Time	0
4066-NS	(1,008,504)
4068-CS	(815,402)
4075-LV Charges	(353,366)
3000-Sales of Electricity Total	**(19,811,587)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(3,573,629)
4080-2-SSS Revenue	(19,500)
4082-RS Rev	0
4084-Serv Tx Requests	0
4090-Electric Services Incidental to Energy Sales	0
3050-Revenues From Services - Distirbution Total	**(3,593,129)**
3100-Other Operating Revenues	
4205-Interdepartmental Rents	0
4210-Rent from Electric Property	(78,200)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	(5,600)
4225-Late Payment Charges	(23,400)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(108,600)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	0
3100-Other Operating Revenues Total	**(215,800)**

3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(94,300)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	64,500
4335-Profits and Losses from Financial Instrument Hedges	0
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	0
4357-Gain from Retirement of Utility and Other Property	0
4362-Loss from Retirement of Utility and Other Property	22,596
4375-Revenues from Non-Utility Operations	(58,800)
4380-Expenses of Non-Utility Operations	37,700
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	0
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0
3150-Other Income & Deductions Total	**(28,304)**

3200-Investment Income	
4405-Interest and Dividend Income	0
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**0**

3350-Power Supply Expenses	
4705-Power Purchased	16,272,196
4708-WMS	1,136,876
4710-Cost of Power Adjustments	0
4712-0	0
4714-NW	1,008,504
4715-System Control and Load Dispatching	0
4716-NCN	815,402
4720-Other Expenses	0
4725-Competition Transition Expense	0
4730-Rural Rate Assistance Expense	225,244
4750-LV Charges	353,366
3350-Power Supply Expenses Total	**19,811,587**

3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	289,509
5010-Load Dispatching	4,080
5012-Station Buildings and Fixtures Expense	0
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0
5016-Distribution Station Equipment - Operation Labour	5,023
5017-Distribution Station Equipment - Operation Supplies and Expenses	21,100
5020-Overhead Distribution Lines and Feeders - Operation Labour	0
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	0
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	1,800
5040-Underground Distribution Lines and Feeders - Operation Labour	0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	0
5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	0
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	5,990
5070-Customer Premises - Operation Labour	48,969
5075-Customer Premises - Materials and Expenses	2,516
5085-Miscellaneous Distribution Expense	0
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**378,987**

3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	118,521
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	0
5114-Mtaint Dist Stn Equip	87,344
5120-Maintenance of Poles, Towers and Fixtures	19,080
5125-Maintenance of Overhead Conductors and Devices	89,700
5130-Maintenance of Overhead Services	0
5135-Overhead Distribution Lines and Feeders - Right of Way	31,222
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	78,949
5155-Maintenance of Underground Services	0
5160-Maintenance of Line Transformers	7,610
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	116,415
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**548,841**

3650-Billing and Collecting	
5305-Supervision	0
5310-Meter Reading Expense	182,423
5315-Customer Billing	206,979
5320-Collecting	83,177
5325-Collecting - Cash Over and Short	102
5330-Collection Charges	918
5335-Bad Debt Expense	25,000
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**498,599**
3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	4,450
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**4,450**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,524
5610-Management Salaries and Expenses	506,320
5615-General Administrative Salaries and Expenses	62,345
5620-Office Supplies and Expenses	110,192
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	50,500
5635-Property Insurance	27,234
5640-Injuries and Damages	16,116
5645-Employee Pensions and Benefits	0
5650-Franchise Requirements	0
5655-Regulatory Expenses	100,697
5660-General Advertising Expenses	0
5665-Miscellaneous Expenses	47,124
5670-Rent	0
5675-Maintenance of General Plant	131,802
5680-Electrical Safety Authority Fees	5,202
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,085,056**

3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	682,735
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	0
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	(72,189)
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**610,546**
3900-Interest Expense	
6005-Interest on Long Term Debt	322,428
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	0
6035-Other Interest Expense	0
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**322,428**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	30,385
3950-Taxes Other Than Income Taxes Total	**30,385**
4000-Income Taxes	
6110-Income Taxes	978
6115-Provision for Future Income Taxes	0
4000-Income Taxes Total	**978**
4100-Extraordinary & Other Items	
6205-Donations	0
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions	0
4100-Extraordinary & Other Items Total	**0**
Net Income - (Gain)/Loss	**(356,962)**

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2013 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON AFFILIATES:

As indicated above, Midland PUC is wholly owned by the Corporation of the Town of Midland. Midland PUC has no affiliate corporations other than the Corporation of the Town of Midland. Midland PUC does not produce an annual report.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued by the Board June 28, 2011 states the relevant default materiality threshold as:

"$50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million"

Since Midland PUC's distribution revenue requirement is less than $10M, Midland PUC has chosen the default of $50,000 as the appropriate materiality threshold in this Application. However, you will note Midland PUC has made every effort to ensure all variances and analysis is prepared, even for variances under $50,000 in order to assist in analyzing Midland PUC's COS Application.

OVERVIEW:

Rate Base Overview:

The rate base used for the purpose of calculating the revenue requirement in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 13% of the sum of the cost of power and controllable expenses. The 13% working capital allowance is consistent with the Board's letter of April 12, 2012.

The net fixed assets include those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. Midland PUC does not have non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

This exhibit will compare historical data with the 2012 Bridge Year and 2013 Test Year. As stated through this application, Midland PUC will be converting to International Financial Reporting Standards (IFRS) in 2013 and has prepared this application under modified IFRS (MIFRS). In order to make the comparisons meaningful, all comparisons will be made under CGAAP. However, in some cases MIFRS information is provided to be of assistance. Midland PUC has also identified changes and the impact to Midland PUC's revenue requirement, relating to the PP&E items below, as per pages 17-20 of the *Report of the Board: Transition to International Financial Reporting Standards (EB-2008-0408)*:

- Asset retirement obligations
- Gains and losses on disposition of assets

Changes to fixed assets and rate base due to the conversion from CGAAP to MIFRS will also be discussed in Tab 5 – Conversion to MIFRS, of this exhibit.

Midland PUC has provided its rate base calculations for the years 2009 OEB Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year (CGAAP & MIFRS) and 2013 Test Year (CGAAP & MIFRS) in Table 2.1.1(a) below. Midland PUC has calculated its 2013 rate base as $ 16,040,975 under MIFRS which will be used to determine the proposed revenue requirement.

Table 2.1.1(a) – Summary of Rate Base

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (CGAAP)	2013 Test (MIFRS)
Gross Fixed Assets	20,919,039	18,831,573	22,109,446	22,909,879	25,678,601	25,229,022	26,770,364	25,954,029
Accumulated Depreciation	10,636,770	10,546,691	11,383,077	12,270,092	13,196,172	12,511,128	13,750,169	12,403,029
Net Book Value	10,282,269	8,284,882	10,726,369	10,639,787	12,482,429	12,717,894	13,020,195	13,551,000
Average Net Book Value	9,234,582	8,149,148	9,505,626	10,683,078	11,460,420	11,578,153	12,751,312	13,134,447
Working Capital	19,881,303	18,410,749	20,051,694	20,678,037	22,677,476	22,677,476	22,357,905	22,357,905
Working Capital Allowance	2,982,195	2,761,612	3,007,754	3,101,705	3,401,621	3,401,621	2,906,528	2,906,528
Rate Base	12,216,778	10,910,761	12,513,380	13,784,783	14,862,042	14,979,774	15,657,839	16,040,975

Table 2.1.1(b) below is a summary of Midland PUC's cost of power and controllable expenses used in calculating working capital for the period 2009 Actual to 2011 Actual, as well as 2009 Board Approved and 2012 Bridge Year and 2013 Test Year under CGAAP and MIFRS.

The changes in working capital are primarily due to the annual changes in cost of power and increases in OM&A expenses. The working capital allowance in the years 2009 OEB Approved, 2009, 2010, 2011 Actual and 2012 Bridge years are based on 15% cost of power and controllable expenses in accordance with the Filing Requirements. As indicated above, the working capital allowance in the year 2013 is based on 13% cost of power and controllable expenses as set out in the Board's letter of April 12, 2012.

There are no differences in Midland PUC's working capital for the years 2012 and 2013 under CGAAP and MIFRS. Midland PUC does not allocate overheads to capital projects under CGAAP that would not be permitted under MIFRS.

Table 2.1.1(b) – Summary of Working Capital Calculation

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (CGAAP)	2013 Test (MIFRS)
Cost of Power	$ 17,781,953	$ 16,591,122	$ 18,173,779	$ 18,857,557	$ 20,427,576	$ 20,427,576	$ 19,811,587	$ 19,811,587
Operations	$ 455,700	$ 325,787	$ 191,621	$ 228,798	$ 349,599	$ 349,599	$ 378,987	$ 378,987
Maintenance	$ 353,900	$ 337,863	$ 436,383	$ 440,148	$ 457,389	$ 457,389	$ 548,841	$ 548,841
Billing & Collecting	$ 435,800	$ 434,238	$ 414,278	$ 239,980	$ 479,686	$ 479,686	$ 498,599	$ 498,599
Community Relations	$ 5,600	$ 1,316	$ 3,900	$ 3,728	$ 3,527	$ 3,527	$ 4,450	$ 4,450
Administration & General Expense	$ 814,150	$ 689,371	$ 801,674	$ 879,150	$ 930,199	$ 930,199	$ 1,085,056	$ 1,085,056
Property Taxes	$ 34,200	$ 31,052	$ 30,058	$ 28,676	$ 29,500	$ 29,500	$ 30,385	$ 30,385
Working Capital	$ 19,881,303	$ 18,410,749	$ 20,051,694	$ 20,678,037	$ 22,677,476	$ 22,677,476	$ 22,357,905	$ 22,357,905

The Midland PUC Distribution System:

Midland PUC owns and operates the electricity distribution system in its licensed service area in the Town of Midland serving approximately 7,000 customers in the Residential and General Service classes. Midland PUC also provides service to Street Lighting and Unmetered Scattered Load customers.

Midland PUC is comprised of approximately 20 square kilometres of high density urban area. Midland PUC's population density (customers per square kilometre) is 350. The bulk of Midland PUC's power is supplied from Hydro One through the Waubaushene TS at 44kV. A small portion of the supply is provided by Hydro One through the Firth's Corners DS.

Some key system statistics follow:

Poles	1,846
Distribution Transformers	1,092

Distribution Stations	6
Km of Overhead Line	101
Km of Underground Line	39

In managing its distribution system assets, Midland PUC's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public & worker safety and customer service expectations. This Application incorporates Midland PUC's 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

Midland PUC considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, system configuration, line loss reduction, outage mitigation and procuring the lowest cost of commodity to determine investment needs in the system.

On an annual basis, Midland PUC reviews capital projects identified for potential implementation and prioritizes each project based on defined criteria basis. All members of the management team follow these criteria as they individually complete outlines of their recommendations, which are then discussed by the full management team. After all recommended projects are examined, they are listed in order from highest to lowest priority and then moved forward based on an "as-needed" basis.

Various studies and assessments of Midland PUC assets are used to determine project priorities. For example, in 2006 Midland PUC commissioned a substation assessment study which provided Midland PUC with a strategic plan moving forward for the replacement of the aging substation infrastructure. This Study was included in Midland PUC's COS Application in 2009. Four of the six substations have been upgraded or replaced in their entirety over the years 2007 to 2010, in accordance with the recommendations provided in the Substation Study report. The Substation Study report was updated to include a Load Study in 2011 which provided recommendations for the remaining two substations. These upgrades will take into consideration the potential for future growth, however, the replacement is undertaken due to the aging infrastructure and redundancy. A copy of the Load Study accompanies this Exhibit as Appendix A.

In addition, Midland PUC's Asset Management Study completed in 2010 and 2011 has provided a Condition Assessment of all poles, transformers, conductors, switches, and reclosures to determine the age, condition and reliability of these distribution system assets. This Study has provided Midland PUC with a strategic plan for the replacement of assets as they reach the end of their useful lives. A copy of the Asset Management Study accompanies this Exhibit as Appendix B.

In addition to the capital needs of the network, Midland PUC provides and plans for system maintenance of the network on a priority basis. The same preparation and consideration steps are undertaken before the final recommended budget amounts are established. Further information on Midland PUC's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Asset Categories

Midland PUC's assets fall into two broad categories **–** The first is ***distribution plant***, which includes assets such as municipal substations, poles, conductors, overhead and underground electricity distribution infrastructure, transformers, and meters. The second is ***general plant*** which includes assets such as: office building and service centre; office furniture; transportation equipment; communications technology; computer equipment and software; general equipment; and tools. A more detailed list of distribution and general plant categories can be found in Table 2.6(a)(b) (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects:

Midland PUC's capital budget items include:

- **Customer Demand:**

These are projects Midland PUC undertakes to meet its customer service obligations in accordance with the OEB's Distribution System Code (the "DSC") and Midland PUC's Conditions of Service. Activities include connecting new customers and building or overseeing construction of distribution systems for new subdivisions. Capital contributions toward the cost of these projects are collected by Midland PUC in accordance with the DSC and the provisions of its Conditions of Service. Midland PUC uses the economic evaluation methodology prescribed by the DSC to determine the level of capital contribution for each project and those levels are included in the annual capital budget.

- **Renewal:**

Renewal projects are completed when assets reach the end of their useful life and must be replaced. As mentioned previously, the Substation Study and Asset Management and Condition Assessment Study referred to has provided Midland PUC with a strategic plan moving forward with capital planning. In addition, Midland PUC completes visual inspections of its plant and performs predictive testing on certain assets where such testing is available and replaces assets based on these inspection and testing activities if warranted. In some cases the projects involve spot replacement of assets; in others, the projects involve complete asset replacement within a geographic area. New assets require less maintenance, deliver better reliability and reduce safety risks to the general public.

- **Security:**

The probability and impact of asset failure are considered at peak load to determine the risk the failure creates. In these cases, projects are developed to add switching devices or create a backup supply (ie. feeder or transformer etc.) to reduce the risk of power outages and to reduce restoration times.

- **Capacity:**

Load growth caused by new customer connections and increased demand of existing customers over time can result in a need for capacity improvements on the system. Projects can take the form of new or upgraded feeders, transformers or voltage conversion projects or substations. These projects benefit many customers.

- **Reliability:**

The main driver for these investments is an analysis of what measures could be undertaken to improve Midland PUC reliability performance as measured by: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). These measures are indicators of the reliability of Midland PUC's distribution system. These activities will support maintenance of, or improvement to, the Service Quality Indices measured and submitted to the OEB each year by Midland PUC. The Asset Management Plan provided in Exhibit 2, Tab 3, Schedule 3 supports the capital and maintenance programs needed to maintain and enhance the reliability of Midland PUC's distribution system.

- **Regulatory Requirements:**

These projects are system capital investments which are being driven by regulatory requirements. These requirements may include, among others, directions from the OEB, the IESO, the Ministry of Energy or the Ministry of Environment.

- **Substations:**

Distribution substations (DS) are used to transform power received from the 44kV sub transmission feeders to either 8.32 kV or 4.16 kV for further distribution. Investments are undertaken to improve or maintain reliability to a large number of customers and to ensure safety and security at the substations. The renewal or retirement of Midland PUC's substations is the subject of an ongoing review being undertaken as part of the Substation

Study referred to below. Midland PUC has been renewing their substations for several years with the objective of completing the remaining two capital substations in 2012 and 2013. The Station facilities include power transformers, circuit breakers, switchgear, bus, insulators, power cables, support structures and ancillary equipment.

- **Customer Connections and Metering:**

Capital expenditures in this pool include meter installations, meter upgrades, and the capital components of wholesale and retail meter verification activities. In 2009, Midland PUC began the installation of smart meters and completed the installation in 2010.

Midland PUC capital projects for the 2013 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2. Midland PUC has provided project-specific justifications for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year. Midland PUC has provided a comparison of Budget (OEB Board Approved/ Midland PUC Board approved) to Actual capital expenditures for the years 2009, 2010 and 2011.

Midland PUC does not capitalize interest. In addition, Midland PUC does not capitalize, through internal cost allocations, indirect administrative support costs such as Finance or Engineering. With the exception of 2009, all capital projects are budgeted for and completed in the fiscal year. In 2009, the substation project was not energized until early 2010. Consequently, the project was reported as construction work in progress in 2009.

Gross Assets – Property, Plant and Equipment and Accumulated Amortization:

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. Analysis of 2009 to 2013 capital programs are described in detail in Midland PUC's written evidence at Exhibit 2, Tab 3, Schedule 2.

Budget Process:

Midland PUC has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. Midland PUC completes ground inspections throughout the year while completing maintenance on the distribution system. In addition, Midland PUC relies on the substation study completed in 2006 that has provided a comprehensive analysis of the substation infrastructure within Midland PUC's distribution area. Midland PUC's distribution system includes six substations. As mentioned previously, Midland PUC has been renewing substations for several years with the objective of completing the remaining two capital substations in 2012 and 2013. The replacement of these substations will take into consideration the potential for future growth; however, the replacement is undertaken due to the aging infrastructure. Midland PUC updated the Substation Study to include a Load Study in 2011, which is used in planning for the upgrade of the remaining two stations.

In addition, Midland PUC's Asset Management Study, sets out the necessary distribution system investments to ensure safe, reliable delivery of electricity to our customers.

The budget is prepared annually by management and is reviewed and approved by the Midland PUC Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results may be evaluated. A comparison to each of the year's budget to actual costs is included in this analysis.

The Midland PUC Board has, on occasion directed Management to revise a Budget following consideration of year-end financial results or major changes in capital job priorities.

Responsibilities:

- It is the responsibility of the Finance department to co-ordinate the development of the operating budget, capital budget and forecast processes.
- The Finance department and Operations department are responsible for preparing their respective operating budget, capital budget, and forecasts.
- The Manager of Operations is responsible for the Operations capital budget and the CFO is responsible for the Admin/Finance capital budget.
- The CEO, Operations Manager and CFO are responsible for presenting and recommending the budget to the Board of Directors for approval.

The budget is an important planning tool for Midland PUC. It puts capital and operational plans into a common financial plan. The final document provides a comprehensive package of departmental budgets to collectively ensure appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. Midland PUC notes these Budget Plans address both capital and operating requirements.

VARIANCE ANALYSIS OF RATE BASE

Tables 2.1.2, 2.1.2(a), 2.1.3, 2.1.4, 2.1.5(a), 2.1.5(b), 2.1.6(a) and 2.1.6(b) set out Midland PUC's year over year rate base variances for the 2009 OEB Approved to 2009 Actual, 2009 to 2010, 2010 to 2011, 2011 to 2012 Bridge Year and 2012 Bridge year to 2013 Test Year. For the purposes of this analysis, Midland PUC will continue to detail variances that are greater than $50,000 as outlined in the materiality section of this Application.

Table 2.1.2: 2009 Approved Rate Base vs. 2009 Actual

Description	2009 OEB Approved	2009 Actual	Variance
Gross Fixed Assets	$ 20,919,039	$ 18,831,573	-$ 2,087,466
Accumulated Depreciation	$ 10,636,770	$ 10,546,691	-$ 90,079
Net Book Value	$ 10,282,269	$ 8,284,882	-$ 1,997,387
Average Net Book Value	$ 9,234,582	$ 8,149,148	-$ 1,085,434
Working Capital	$ 19,881,303	$ 18,410,749	-$ 1,470,554
Working Capital Allowance	$ 2,982,195	$ 2,761,612	-$ 220,583
Rate Base	$ 12,216,778	$ 10,910,761	-$ 1,306,017

The 2009 OEB Approved Gross Fixed Assets and Accumulated Amortization amounts differ significantly from Midland PUC's audited statements. The Fourth St substation was not fully completed until 2010. Total costs for the substation included $1,072,527 in 2009 and $179,886 in 2010 for a total project cost of $1,252,413 vs. a budget of $1,262,800. The 2009 costs were recorded as WIP in 2009 not as fixed assets, but were included in the 2009 OEB Approved Gross Fixed Assets.

Other 2009 capital spending reductions included an adjustment made to the 2008 capital of $230,007 for work prepaid in 2008 which was deferred until 2012. Midland PUC received a refund of the 2008 prepayment in 2009. See 2009 Capital Project #6: Brandon St Substation.

In addition, projected spending through the Economic Evaluation Development System Expansion process included in the 2009 Board Approved totalled $400,000. Actual net spending in 2009 was $116,132 – see 2009 Project #7: Economic Evaluations System Expansions. Consequently, capital spending was reduced by $283,868.

Account #1995 Contributions and Grants included $273,500 in the 2009 Board Approved vs. actual contributions received of $523,731 in 2009, a difference of $250,231.

Net Transportation Equipment purchases were $46,045 less than 2009 Board Approved due to the removal of a trailer and small pick up truck.

Two projects, Bourgeois Lane Kiosk ($159,200) was not completed in 2009, however, other work (Miscellaneous Work Project 10 and Montreal Substation Project 5) was completed during 2009 but was not included in the 2009 Board Approved.

A summary of these variances is included as Table 2.1.2(a) below:

Table 2.1.2(a): Gross Fixed Asset Variances – 2009

Description	Project	
Fourth St Substation	$	1,072,527
Brandon St. Substation	$	230,007
Economic Evaluations	$	283,868
Contributed Capital	$	250,231
Transportation	$	46,045
Bourgeois Lane Kiosk	$	159,200
Miscellaneous Capital	$	45,588
Total Gross Fixed Asset Variance	**$**	**2,087,466**

The 2009 Actual Working Capital has also been reduced in comparison to the 2009 Board Approved due to the reduction in Cost of Power from Board Approved of $1,190,831 ($17,781,953 Approved to $16,591,122 Actual). As well, actual expenses in 2009 were less than Board Approved in the amount of $279,723.

The 2009 actual rate base was -$ 1,306,017 lower than 2009 Board Approved. -$ 220,583 of this amount was due to lower working capital expenses than anticipated. The remaining -$ 1,085,434 is the result of the reduction in capital spending and amortization.

Exhibit 2, Tab 2, Schedule 1 – Continuity Statements, contain more details.

Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are more particularly described in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.3 2009 Actual vs. 2010 Actual

Description	2009 Actual	2010 Actual	Variance
Gross Fixed Assets	$ 18,831,573	$ 22,109,446	$ 3,277,873
Accumulated Depreciation	$ 10,546,691	$ 11,383,077	$ 836,386
Net Book Value	$ 8,284,882	$ 10,726,369	$ 2,441,487
Average Net Book Value	$ 8,149,148	$ 9,505,626	$ 1,356,477
Working Capital	$ 18,410,749	$ 20,051,694	$ 1,640,945
Working Capital Allowance	$ 2,761,612	$ 3,007,754	$ 246,142
Rate Base	$ 10,910,761	$ 12,513,380	$ 1,602,619

The rate base of $ 12,513,380 for 2010 increased by $ 1,602,619 over 2009. This increase is primarily the result of an increase in fixed assets of $ 2,441,487 due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.4: 2010 Actual vs. 2011 Actual

Description	2010 Actual	2011 Actual	Variance
Gross Fixed Assets	$ 22,109,446	$ 22,909,879	$ 800,433
Accumulated Depreciation	$ 11,383,077	$ 12,270,092	$ 887,016
Net Book Value	$ 10,726,369	$ 10,639,787	-$ 86,582
Average Net Book Value	$ 9,505,626	$ 10,683,078	$ 1,177,452
Working Capital	$ 20,051,694	$ 20,678,037	$ 626,343
Working Capital Allowance	$ 3,007,754	$ 3,101,705	$ 93,951
Rate Base	$ 12,513,380	$ 13,784,783	$ 1,271,404

The rate base of $ 13,784,783 for 2011 increased by $ 1,271,404 over 2010. This increase is primarily the result of an increase in average fixed assets of $ 1,177,452 due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.5(a): 2011 Actual vs. 2012 Bridge Year (CGAAP)

Description	2011 Actual	2012 Bridge (CGAAP)	Variance
Gross Fixed Assets	$ 22,909,879	$ 25,678,601	$ 2,768,722
Accumulated Depreciation	$ 12,270,092	$ 13,196,172	$ 926,080
Net Book Value	$ 10,639,787	$ 12,482,429	$ 1,842,642
Average Net Book Value	$ 10,683,078	$ 11,460,420	$ 777,343
Working Capital	$ 20,678,037	$ 22,677,476	$ 1,999,440
Working Capital Allowance	$ 3,101,705	$ 3,401,621	$ 299,916
Rate Base	$ 13,784,783	$ 14,862,042	$ 1,077,258

In 2012 CGAAP, rate base is forecast to increase by $ 1,077,258 over 2011. The average net book value of assets increased significantly due to the introduction of the smart metering infrastructure into capital from Regulatory Assets, the completion of the Montreal Substation and additional capital spending in 2012. The 2012 working capital allowance increased by $ 299,916 from the 2011 Actuals. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.5(b): 2011 Actual vs. 2012 Bridge Year (MIFRS)

Description	2011 Actual	2012 Bridge (MIFRS)	Variance
Gross Fixed Assets	$ 22,909,879	$ 25,229,022	$ 2,319,143
Accumulated Depreciation	$ 12,270,092	$ 12,511,128	$ 241,035
Net Book Value	$ 10,639,787	$ 12,717,894	$ 2,078,107
Average Net Book Value	$ 10,683,078	$ 11,578,153	$ 895,075
Working Capital	$ 20,678,037	$ 22,677,476	$ 1,999,440
Working Capital Allowance	$ 3,101,705	$ 3,401,621	$ 299,916
Rate Base	$ 13,784,783	$ 14,979,774	$ 1,194,991

In 2012 under MIFRS, rate base is forecast to increase by $ 1,194,991 over 2011. The average net book value of assets increased significantly due to the introduction of the smart metering infrastructure into capital from Regulatory Assets, the completion of the Montreal Substation and additional capital spending in 2012. In addition, under MIFRS the Net Book Value has increased. The 2012 working capital allowance increased by $ 299,916 from the 2011 Actuals, but remains unchanged from CGAAP as there are no adjustments to OM&A expenses or Cost of Power relating to the transition to MIFRS.

Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides details. Calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.6(a): 2012 vs. 2013 Test Year (CGAAP)

Description	2012 Bridge	2013 Test	Variance
Gross Fixed Assets	$ 25,678,601	$ 26,770,364	$ 1,091,762
Accumulated Depreciation	$ 13,196,172	$ 13,750,169	$ 553,997
Net Book Value	$ 12,482,429	$ 13,020,195	$ 537,766
Average Net Book Value	$ 11,460,420	$ 12,751,312	$ 1,290,892
Working Capital	$ 22,677,476	$ 22,357,905	-$ 319,571
Working Capital Allowance	$ 3,401,621	$ 2,906,528	-$ 495,094
Rate Base	$ 14,862,042	$ 15,657,839	$ 795,798

In 2013, rate base is forecast to increase by $ 795,798 over 2012 Bridge Year under CGAAP. The average net book value of assets increased significantly due to the full year inclusion of the Montreal Substation completed in 2012, the inclusion of the Queen Street Substation in 2013 and additional capital spending in 2013. The removal of stranded meters reduced the average net book value in 2013. The 2013 working capital allowance decreased by -$ 495,094 from the 2012 Bridge Year as overall spending reduced in

2013 mainly due to the inclusion of the smart meter infrastructure in 2012 and the reduction of the Working Capital Allowance to 13% from 15% in 2012.

Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides details. Calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

Table 2.1.6(b): 2012 vs. 2013 Test Year (MIFRS)

Description	2012 Bridge (MIFRS)	2013 Test (MIFRS)	Variance
Gross Fixed Assets	$ 25,229,022	$ 25,954,029	$ 725,007
Accumulated Depreciation	$ 12,511,128	$ 12,403,029	-$ 108,099
Net Book Value	$ 12,717,894	$ 13,551,000	$ 833,106
Average Net Book Value	$ 11,578,153	$ 13,134,447	$ 1,556,294
Working Capital	$ 22,677,476	$ 22,357,905	-$ 319,571
Working Capital Allowance	$ 3,401,621	$ 2,906,528	-$ 495,094
Rate Base	$ 14,979,774	$ 16,040,975	$ 1,061,200

In 2013 under MIFRS, rate base is forecast to increase by $ 1,061,200 over 2012 Bridge Year MIFRS. The average net book value of assets increased significantly due to the full year inclusion of the Montreal Substation completed in 2012, the inclusion of the Queen Street Substation in 2013 and additional capital spending in 2013. The removal of stranded meters reduced the average net book value in 2013. In addition, under MIFRS the Net Book Value has increased due to the decrease in amortization as a result of the increase in typical useful lives of distribution assets. The 2013 working capital allowance which decreased by -$ 495,094 from the 2012 Bridge Year MIFRS remains unchanged from CGAAP as there are no adjustments to OM&A expenses or Cost of Power relating to the transition to MIFRS.

Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides details. Calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION:

Continuity Statements

Tables 2.2.1, 2.2.2, 2.2.3, 2.2.4(a), 2.2.4 (b), 2.2.5(a) and 2.2.5(b) below provide details of the Fixed Asset Continuity Schedules for the years 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year under CGAAP. Tables 2.2.4(b) and 2.2.5(b) provide details of the Fixed Asset Continuity Schedules for the 2012 Bridge Year and 2013 Test Year under MIFRS. Table 2.2.6(a) and Table 2.2.6(b) below provides details of Variances of Gross Assets year over year from 2008 Actual through to 2013 Test Year based on Canadian Generally Accepted Accounting Principles (CGAAP) and MIFRS for the 2012 Bridge Year and 2013 Test Year.

Midland PUC uses the following accounts and descriptions in the calculations of its net fixed assets:

1805 – Land: This account is used to record the cost of land held by Midland PUC, used in connection with distribution.

1806 -Land Rights: This account is used to record the cost of rights, interests, easements and privileges held by the LDC in land owned by others.

1820 - Distribution Station Equipment – Normally 1 Primary below 50 kV: This account is used to record the installed cost of transforming and switching equipment in each of Midland PUC's distribution stations, used for the purpose of stepping down to distribution voltages. In Midland PUC's financial system, costs are separated for each distribution station. The detail of stations has been tracked in such a manner that an accurate record of their age, cost, location and voltage characteristics are evident.

1830 - Poles, Towers and Fixtures: This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and service wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. Midland PUC has approximately 1,846 poles within its service territory.

1835 - Overhead Conductors and Devices: This account is used to record the installed cost of overhead conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB. Midland PUC has approximately 101 kilometers of overhead line within its service territory.

1840 - Underground Conduit: This account is used to record the installed cost of underground conduit and tunnels used for housing distribution cables or wires in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1845 - Underground Conductors and Devices: This account is used to record the installed cost of underground conductors and devices used for distribution purposes in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1850 - Distribution Transformers: This account is used to record the installed cost of overhead and underground distribution line transformers and pole type and underground voltage regulators owned by the utility for use in transforming electricity to the voltage at which it is to be used by the customer in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1855 - Services: This account is used to record the installed cost of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system of the transformers, or manhole, or the top of the pole of the distribution line to the point of connection with the customers' electrical panel, in accordance with the example items from the Accounting Procedures Handbook issued by the OEB.

1860 - Meters: This account is used to record the installed cost of meters or devices for use in measuring the electricity delivered to its users, (including Smart Meters). In Midland PUC's metering sub-system, meters are identified by type, capacity and function.

1908 - Buildings and Fixtures: This account includes the costs of buildings and fixtures used for utility purposes owned by Midland PUC.

1915 – Office Furniture & Equipment: This account contains the cost of general office furniture and equipment. In Midland PUC's financial system, the items in this account are considered unique, identifiable assets.

1920 – Computer Equipment -Hardware: This account includes costs of all computer hardware purchased. Hardware is inclusive of all physical equipment associated with input, processing, storage and output functions, also word processing equipment. In Midland PUC's financial systems, the items in this account are considered unique, identifiable assets.

1925 – Computer Software: This account contains the installed costs of all computer software purchased or developed in house. In Midland PUC's financial system, the items in this account are considered unique, identifiable assets.

1930 – Transportation Equipment: This account contains the costs of all vehicles owned by Midland PUC, including automobiles, small trucks, truck chassis, special truck bodies, and other mobile equipment. The items in this account are considered unique and identifiable assets.

1935 – Stores Equipment: This account includes the cost of equipment used in Midland PUC's warehouse for shipping, receiving, handling and storage of materials and supplies. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1940 – Tools, Shop and Garage Equipment: This account contains the cost of all tools and non-power equipment purchased by Midland PUC in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1945 – Measurement and Testing Equipment: This account contains the cost of all measurement and testing equipment purchased by Midland PUC in accordance with the example items from the Accounting Procedures Handbook (APH) issued by the OEB. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1955 – Communications Equipment: This account includes amounts relating to telephone and wireless equipment for the general use in connection with utility operations. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1960 – Miscellaneous Equipment: This account includes amounts relating to equipment, apparatus, etc. used in the LDC operations which are not included in other accounts. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1980 – System Supervisory Equipment: This account includes amounts relating to control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment. In Midland PUC's financial system, the items in this account are considered unique and identifiable assets.

1995 – Contributions and Grants: This account includes amounts relating to contribution or grants in cash, services or property from government or government agencies, corporation, individuals and others who received in aid of construction or for acquisition of fixed assets (contributed capital.) In Midland PUC's financial system, separate records are kept as to the identity of the project and the contributor.

CONVERSION TO MODIFIED INTERNATIONAL REPORTING STANDARDS

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in some changes to Midland PUC's accounting for Property Plant and Equipment (PP&E).

Midland PUC has elected to take the IFRS 1 Exemption for rate regulated entities, which allows for the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided below for the 2012 Bridge Year and 2013 Test Year.

COMPONENTIZATION AND AMORTIZATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost to be depreciated separately. In addition IAS 16 requires that entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

Midland PUC has reviewed the useful lives of its assets with the aid of the Kinectrics Report K-418033-RA-001-R000, entitled "Asset Depreciation Study for the Ontario Energy Board", dated July 8th, 2010. Midland PUC has restated its continuity statements for the 2012 Bridge year and 2013 Test year to include these changes. These changes are presented under the MIFRS schedules below.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. Midland PUC will continue to use the Cost Model to measure PP&E.

Table 2.2.1: Fixed Asset Continuity Schedule - 2009

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)					$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)					$ -				$ -	$ -
N/A	1805	Land		$ 365,298	$ 16,440		$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ 32,555			$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
47	1815	Transformer Station Equipment >50 kV		$ -			$ -		$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 2,533,666	$ 81,349		$ 2,615,015	$ 931,478	$ 84,954	$ -	$ 1,016,431	$ 1,598,584
47	1825	Storage Battery Equipment		$ -			$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 3,605,488	$ 433,638		$ 4,039,127	$ 1,899,570	$ 117,398	$ -	$ 2,016,968	$ 2,022,158
47	1835	Overhead Conductors & Devices		$ 1,950,199	-$ 100,491		$ 1,849,708	$ 935,705	$ 57,823	$ -	$ 993,529	$ 856,179
47	1840	Underground Conduit		$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices		$ 2,757,214	$ 302,532		$ 3,059,746	$ 1,815,120	$ 110,423	$ -	$ 1,925,543	$ 1,134,203
47	1850	Line Transformers		$ 2,915,562	$ 205,337		$ 3,120,898	$ 1,641,447	$ 103,925	$ -	$ 1,745,372	$ 1,375,526
47	1855	Services (Overhead & Underground)		$ 106,379	$ 61,583		$ 167,962	$ -	$ 5,425	$ -	$ 5,425	$ 162,538
47	1860	Meters		$ 1,040,200	$ 4,092		$ 1,044,292	$ 593,997	$ 35,879	$ -	$ 629,876	$ 414,416
47	1860	Meters (Smart Meters)		$ -			$ -		$ -	$ -	$ -	$ -
N/A	1905	Land					$ -		$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 942,341	$ 23,865		$ 966,206	$ 349,199	$ 30,850	$ -	$ 380,049	$ 586,157
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 249,144			$ 249,144	$ 215,420	$ 6,817	$ -	$ 222,236	$ 26,907
8	1915	Office Furniture & Equipment (5 years)		$ -	$ 2,087		$ 2,087	$ -	$ -	$ -	$ -	$ 2,087
50	1920	Computer Equipment - Hardware		$ 398,812	$ 31,529		$ 430,341	$ 371,608	$ 12,968	$ -	$ 384,576	$ 45,765
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		0			$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)		0			$ -	$ -	$ -	$ -	$ -	$ -
12	1925	Software		$ 282,537	$ 23,218		$ 305,754	$ 150,773	$ 46,205	$ -	$ 196,978	$ 108,776
10	1930	Transportation Equipment		$ 847,466	$ 377,620	-$ 177,812	$ 1,047,274	$ 509,363	$ 87,321	-$ 177,812	$ 418,871	$ 628,403
8	1935	Stores Equipment		$ 8,610			$ 8,610	$ 8,487	$ 123	$ -	$ 8,610	$ 0
8	1940	Tools, Shop & Garage Equipment		$ 242,712	$ 17,153		$ 259,865	$ 178,702	$ 8,748	$ -	$ 187,449	$ 72,415
8	1945	Measurement & Testing Equipment		$ 2,634	$ -		$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -			$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 132,253	$ -		$ 132,253	$ 128,161	$ 2,046	$ -	$ 130,207	$ 2,046
8	1955	Communication Equipment (Smart Meters)		$ -			$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -		$ 19,220	$ 17,486	$ 592	$ -	$ 18,078	$ 1,142
47	1975	Load Management Controls Utility Premises		$ -				$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 357,012	$ -		$ 357,012	$ 226,695	$ 22,104	$ -	$ 248,799	$ 108,213
47	1985	Miscellaneous Fixed Assets		$ -				$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 784,980	-$ 523,731	$ 48,845	-$ 1,259,866	$ -	-$ 48,845	$ 48,845	$ -	-$ 1,259,866
WIP		Work In Process			$ 1,072,527		$ 1,072,527	$ -		$ -	$ -	$ 1,072,527
												$ -
		Total		**$ 18,004,321**	**$ 2,028,747**	**-$ 128,967**	**$ 19,904,100**	**$ 9,990,906**	**$ 684,753**	**-$ 128,967**	**$ 10,546,691**	$ 9,357,409

Table 2.2.2: Fixed Asset Continuity Schedule – 2010

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 2,615,015	$ 2,408,291	$ -	$ 5,023,306	$ 1,016,431	$ 134,726	$ -	$ 1,151,157	$ 3,872,148
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,039,127	$ 175,868	$ -	$ 4,214,995	$ 2,016,968	$ 123,015	$ -	$ 2,139,983	$ 2,075,011
47	1835	Overhead Conductors & Devices		$ 1,849,708	$ 199,841	$ -	$ 2,049,549	$ 993,529	$ 60,598	$ -	$ 1,054,126	$ 995,423
47	1840	Underground Conduit		$ -	$ 2,092	$ -	$ 2,092	$ -	$ -	$ -	$ -	$ 2,092
47	1845	Underground Conductors & Devices		$ 3,059,746	$ 202,641	$ -	$ 3,262,387	$ 1,925,543	$ 120,568	$ -	$ 2,046,110	$ 1,216,277
47	1850	Line Transformers		$ 3,120,898	$ 225,109	$ -	$ 3,346,007	$ 1,745,372	$ 111,062	$ -	$ 1,856,434	$ 1,489,573
47	1855	Services (Overhead & Underground)		$ 167,962	$ 15,005	$ -	$ 182,968	$ 5,425	$ 6,962	$ -	$ 12,387	$ 170,581
47	1860	Meters		$ 1,044,292	$ 21,354	$ -	$ 1,065,646	$ 629,876	$ 36,388	$ -	$ 666,264	$ 399,382
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 966,206	$ 23,598	-$ 5,442	$ 984,361	$ 380,049	$ 32,036	-$ 1,058	$ 411,026	$ 573,335
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 251,230	$ 7,799	$ -	$ 259,029	$ 222,236	$ 6,464	$ -	$ 228,700	$ 30,329
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 430,341	$ 28,567	$ -	$ 458,908	$ 384,576	$ 16,280	$ -	$ 400,856	$ 58,052
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1925	Software		$ 305,754	$ 40,000	$ -	$ 345,754	$ 196,978	$ 47,140	$ -	$ 244,118	$ 101,636
10	1930	Transportation Equipment		$ 1,047,274	$ -	$ -	$ 1,047,274	$ 418,871	$ 108,389	$ -	$ 527,261	$ 520,013
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	$ 0
8	1940	Tools, Shop & Garage Equipment		$ 259,865	$ 6,263	$ -	$ 266,128	$ 187,449	$ 9,918	$ -	$ 197,367	$ 68,761
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 132,253	$ 1,857	$ -	$ 134,110	$ 130,207	$ 1,524	$ -	$ 131,731	$ 2,379
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,078	$ 523	$ -	$ 18,601	$ 619
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 357,012	$ 95,117	$ -	$ 452,129	$ 248,799	$ 21,853	$ -	$ 270,652	$ 181,477
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 1,259,866	-$ 234,087	$ 64,002	-$ 1,429,952	$ -	-$ 64,002	$ 64,002	$ -	-$ 1,429,952
WIP		Work in Process		$ 1,072,527	$ -	-$ 1,072,527	$ -	$ -	$ -	$ -	$ -	$ -
		Total		**$ 19,904,100**	**$ 3,219,313**	**-$ 1,013,968**	**$ 22,109,446**	**$ 10,546,691**	**$ 773,443**	**$ 62,943**	**$ 11,383,077**	**$ 10,726,369**

Table 2.2.3: Fixed Asset Continuity Schedule – 2011

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,023,306	$ 18,427	$ -	$ 5,041,733	$ 1,151,157	$ 183,578	$ -	$ 1,334,736	$ 3,706,997
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,214,995	$ 368,740	$ -	$ 4,583,735	$ 2,139,983	$ 136,175	$ -	$ 2,276,158	$ 2,307,577
47	1835	Overhead Conductors & Devices		$ 2,049,549	$ 148,123	$ -	$ 2,197,671	$ 1,054,126	$ 67,071	$ -	$ 1,121,197	$ 1,076,474
47	1840	Underground Conduit		$ 2,092	$ 1,514	$ -	$ 3,605	$ -	$ -	$ -	$ -	$ 3,605
47	1845	Underground Conductors & Devices		$ 3,262,387	$ 65,680	-$ 2,407	$ 3,325,660	$ 2,046,110	$ 124,523	-$ 2,407	$ 2,168,226	$ 1,157,434
47	1850	Line Transformers		$ 3,346,007	$ 77,346	$ -	$ 3,423,353	$ 1,856,434	$ 114,494	$ -	$ 1,970,928	$ 1,452,425
47	1855	Services (Overhead & Underground)		$ 182,968	$ 121,455	$ -	$ 304,423	$ 12,387	$ 12,642	$ -	$ 25,029	$ 279,394
47	1860	Meters		$ 1,065,646	$ 38,813	$ -	$ 1,104,459	$ 666,264	$ 36,831	$ -	$ 703,094	$ 401,364
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 984,361	$ 41,411	$ -	$ 1,025,772	$ 411,026	$ 33,389	$ -	$ 444,415	$ 581,357
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 259,029	$ 16,519	-$ 15,524	$ 260,024	$ 228,700	$ 7,419	-$ 10,091	$ 226,029	$ 33,995
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 458,908	$ 6,075	$ -	$ 464,983	$ 400,856	$ 18,419	$ -	$ 419,275	$ 45,708
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1925	Software		$ 345,754	$ 17,303	$ -	$ 363,056	$ 244,118	$ 48,329	$ -	$ 292,447	$ 70,610
10	1930	Transportation Equipment - Large Vehicles		$ 858,183	$ -	$ -	$ 858,183	$ 392,907	$ 90,056	$ -	$ 482,962	$ 375,221
10	1930	Transportation Equipment - Small Vehicles		$ 189,091	$ 2,425	-$ 30,492	$ 161,023	$ 134,354	$ 18,333	-$ 30,492	$ 122,196	$ 38,828
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	$ 0
8	1940	Tools, Shop & Garage Equipment		$ 266,128	$ 6,697	$ -	$ 272,825	$ 197,367	$ 10,523	$ -	$ 207,890	$ 64,934
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 131,731	$ 300	$ -	$ 132,031	$ 2,079
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,601	$ 177	$ -	$ 18,778	$ 442
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 452,129	$ 110,198	$ -	$ 562,328	$ 270,652	$ 27,745	$ -	$ 298,397	$ 263,931
47	1985	Miscellaneous Fixed Assets				$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 1,429,952	-$ 265,869	$ 74,001	-$ 1,621,821	$ -	-$ 74,001	$ 74,001	$ -	-$ 1,621,821
	etc.						$ -				$ -	$ -
		Total		**$ 22,109,446**	**$ 774,856**	**$ 25,578**	**$ 22,909,879**	**$ 11,383,077**	**$ 856,004**	**$ 31,011**	**$ 12,270,092**	**$ 10,639,787**

Table 2.2.4(a): Fixed Asset Continuity Schedule – 2012 (CGAAP)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 47,616
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,041,733	$ 563,200	$ -	$ 5,604,933	$ 1,334,736	$ 194,913	$ -	$ 1,529,649	$ 4,075,284
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,583,735	$ 323,600	$ -	$ 4,907,335	$ 2,276,158	$ 137,291	$ -	$ 2,413,449	$ 2,493,886
47	1835	Overhead Conductors & Devices		$ 2,197,671	$ 91,160	$ -	$ 2,288,831	$ 1,121,197	$ 67,621	$ -	$ 1,188,818	$ 1,100,013
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,330,392	$ 72,830	$ -	$ 1,403,222	$ 545,719
47	1845	Underground Conductors & Devices		$ 1,380,324	$ 392,500	$ -	$ 1,772,824	$ 837,834	$ 45,866	$ -	$ 883,700	$ 889,124
47	1850	Line Transformers		$ 3,423,353	$ 303,600	$ -	$ 3,726,953	$ 1,970,928	$ 114,630	$ -	$ 2,085,558	$ 1,641,395
47	1855	Services (Overhead & Underground)		$ 304,423	$ 33,900	$ -	$ 338,323	$ 25,029	$ 12,797	$ -	$ 37,826	$ 300,497
47	1860	Meters		$ 1,104,459	$ 13,000	$ -	$ 1,117,459	$ 703,094	$ 35,988	$ -	$ 739,082	$ 378,376
47	1860	Meters (Smart Meters)		$ -	$ 1,204,471	$ -	$ 1,204,471	$ 172,164	$ 79,697	$ -	$ 251,861	$ 952,610
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,025,772	$ 45,000	$ -	$ 1,070,772	$ 444,415	$ 35,421	$ -	$ 479,836	$ 590,936
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 226,029	$ 7,499	$ -	$ 233,528	$ 26,496
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 464,983	$ 29,500	$ -	$ 494,483	$ 419,275	$ 19,649	$ -	$ 438,924	$ 55,559
50	1920	Computer Equip.-Hardware(Smart Meters)		$ -	$ 18,764	$ -	$ 18,764	$ 7,379	$ 3,753	$ -	$ 11,132	$ 7,632
12	1925	Software		$ 363,056	$ 10,200	$ -	$ 373,256	$ 292,447	$ 32,289	$ -	$ 324,735	$ 48,521
12	1925	Software (Smart Meters)		$ -	$ 68,016	$ -	$ 68,016	$ 21,832	$ 13,603	$ -	$ 35,435	$ 32,581
10	1930	Transportation Equipment - Large Vehicles		$ 858,183	$ 525,400	-$ 372,388	$ 1,011,195	$ 482,962	$ 93,562	-$ 297,556	$ 278,968	$ 732,227
10	1930	Transportation Equipment - Small Vehicles		$ 161,023	$ 10,800	$ -	$ 171,823	$ 122,196	$ 16,180	$ -	$ 138,376	$ 33,448
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	$ 0
8	1940	Tools, Shop & Garage Equipment		$ 272,825	$ 16,900	$ -	$ 289,725	$ 207,890	$ 11,616	$ -	$ 219,506	$ 70,218
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,031	$ 300	$ -	$ 132,331	$ 1,779
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,778	$ 177	$ -	$ 18,955	$ 265
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ -	$ -	$ 562,328	$ 298,397	$ 26,580	$ -	$ 324,977	$ 237,351
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 1,621,821	-$ 594,100	$ 85,200	-$ 2,130,721	$ -	-$ 85,200	$ 85,200	-$ 0	-$ 2,130,721
	etc.						$ -				$ -	$ -
												$ -
		Total		**$ 22,909,879**	**$ 3,055,911**	**-$ 287,188**	**$ 25,678,601**	**$ 12,471,467**	**$ 937,061**	**-$ 212,356**	**$ 13,196,172**	$ 12,482,429

Table 2.2.4(b): Fixed Asset Continuity Schedule – 2012 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,041,733	$ 563,200	-$ 192,651	$ 5,412,282	$ 1,334,736	$ 139,209	-$ 134,498	$ 1,339,447	$ 4,072,835
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,583,735	$ 323,600	-$ 114,540	$ 4,792,795	$ 2,276,158	$ 70,682	-$ 101,673	$ 2,245,167	$ 2,547,628
47	1835	Overhead Conductors & Devices		$ 2,197,671	$ 91,160	-$ 52,043	$ 2,236,788	$ 1,121,197	$ 24,472	-$ 51,162	$ 1,094,508	$ 1,142,280
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,330,392	$ 16,021	$ -	$ 1,346,413	$ 602,528
47	1845	Underground Conductors & Devices		$ 1,380,324	$ 392,500	$ -	$ 1,772,824	$ 837,834	$ 30,372	$ -	$ 868,206	$ 904,618
47	1850	Line Transformers		$ 3,423,353	$ 303,600	-$ 54,870	$ 3,672,084	$ 1,970,928	$ 55,449	-$ 51,201	$ 1,975,176	$ 1,696,908
47	1855	Services (Overhead & Underground)		$ 304,423	$ 33,900	$ -	$ 338,323	$ 25,029	$ 5,015	$ -	$ 30,044	$ 308,279
47	1860	Meters		$ 1,104,459	$ 13,000	$ -	$ 1,117,459	$ 703,094	$ 35,988	$ -	$ 739,082	$ 378,376
47	1860	Meters (Smart Meters)		$ -	$ 1,204,471	$ -	$ 1,204,471	$ 172,164	$ 75,774	$ -	$ 247,938	$ 956,533
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,025,772	$ 45,000	$ -	$ 1,070,772	$ 444,415	$ 16,792	$ -	$ 461,208	$ 609,564
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 226,029	$ 5,379	$ -	$ 231,408	$ 28,616
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 464,983	$ 29,500	$ -	$ 494,483	$ 419,275	$ 19,649	$ -	$ 438,924	$ 55,559
45	1920	Computer Equip.-Hardware(Smart Meters)		$ -	$ 18,764	$ -	$ 18,764	$ 7,379	$ 3,753	$ -	$ 11,132	$ 7,632
52	1925	Software		$ 363,056	$ 10,200	$ -	$ 373,256	$ 292,447	$ 32,289	$ -	$ 324,735	$ 48,521
12	1925	Software (Smart Meters)		$ -	$ 68,016	$ -	$ 68,016	$ 21,832	$ 13,603	$ -	$ 35,435	$ 32,581
10	1930	Transportation Equipment - Large Vehicles		$ 858,183	$ 525,400	-$ 372,388	$ 1,011,195	$ 482,962	$ 93,562	-$ 297,556	$ 278,968	$ 732,227
	1930	Transportation Equipment - Small Vehicles		$ 161,023	$ 10,800	$ -	$ 171,823	$ 122,196	$ 9,601	$ -	$ 131,797	$ 40,027
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	-$ 0
8	1940	Tools, Shop & Garage Equipment		$ 272,825	$ 16,900	$ -	$ 289,725	$ 207,890	$ 11,616	$ -	$ 219,506	$ 70,218
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,031	$ 300	$ -	$ 132,331	$ 1,779
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,778	$ 177	$ -	$ 18,955	$ 265
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ -	$ -	$ 562,328	$ 298,397	$ 16,047	$ -	$ 314,444	$ 247,883
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 1,621,821	-$ 594,100	$ 49,724	-$ 2,166,197	$ -	-$ 49,724	$ 49,724	$ -	-$ 2,166,197
	etc.						$ -				$ -	$ -
		Total		**$ 22,909,879**	**$ 3,055,911**	**-$ 736,768**	**$ 25,229,022**	**$ 12,471,467**	**$ 626,027**	**-$ 586,366**	**$ 12,511,128**	**$ 12,717,894**

Table 2.2.5(a): Fixed Asset Continuity Statement – 2013 (CGAAP)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,604,933	$ 896,700	$ -	$ 6,501,633	$ 1,529,649	$ 224,111	$ -	$ 1,753,760	$ 4,747,872
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,907,335	$ 353,100	$ -	$ 5,260,435	$ 2,413,449	$ 146,838	$ -	$ 2,560,287	$ 2,700,148
47	1835	Overhead Conductors & Devices		$ 2,288,831	$ 99,700	$ -	$ 2,388,531	$ 1,188,818	$ 72,323	$ -	$ 1,261,141	$ 1,127,390
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,403,222	$ 71,983	$ -	$ 1,475,205	$ 473,736
47	1845	Underground Conductors & Devices		$ 1,772,824	$ 387,500	$ -	$ 2,160,324	$ 883,700	$ 45,333	$ -	$ 929,032	$ 1,231,292
47	1850	Line Transformers		$ 3,726,953	$ 318,900	$ -	$ 4,045,853	$ 2,085,558	$ 117,279	$ -	$ 2,202,837	$ 1,843,016
47	1855	Services (Overhead & Underground)		$ 338,323	$ 30,900	$ -	$ 369,223	$ 37,826	$ 14,093	$ -	$ 51,919	$ 317,304
47	1860	Meters		$ 1,117,459	$ 10,000	-$ 801,102	$ 326,357	$ 739,082	$ 33,914	-$ 543,986	$ 229,011	$ 97,346
47	1860	Meters (Smart Meters)		$ 1,204,471	$ -	$ -	$ 1,204,471	$ 251,861	$ 79,697	$ -	$ 331,558	$ 872,913
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,070,772	$ 25,000	$ -	$ 1,095,772	$ 479,836	$ 37,171	$ -	$ 517,007	$ 578,765
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 233,528	$ 6,566	$ -	$ 240,094	$ 19,930
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 494,483	$ 22,200	$ -	$ 516,683	$ 438,924	$ 20,147	$ -	$ 459,071	$ 57,612
50	1920	Computer Equip.-Hardware(Smart Meters)		$ 18,764	$ -	$ -	$ 18,764	$ 11,132	$ 5,973	$ -	$ 17,105	$ 1,659
12	1925	Software		$ 373,256	$ 55,000	$ -	$ 428,256	$ 324,735	$ 23,911	$ -	$ 348,647	$ 79,610
12	1925	Software (Smart Meters)		$ 68,016	$ -	$ -	$ 68,016	$ 35,435	$ 13,603	$ -	$ 49,038	$ 18,978
10	1930	Transportation Equipment - Large Vehicles		$ 1,011,195	$ -	$ -	$ 1,011,195	$ 278,968	$ 126,399	$ -	$ 405,368	$ 605,828
10	1930	Transportation Equipment - Small Vehicles		$ 171,823	$ -	$ -	$ 171,823	$ 138,376	$ 13,421	$ -	$ 151,797	$ 20,027
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	$ 0
8	1940	Tools, Shop & Garage Equipment		$ 289,725	$ 10,000	$ -	$ 299,725	$ 219,506	$ 12,961	$ -	$ 232,467	$ 67,257
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,331	$ 300	$ -	$ 132,631	$ 1,479
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,955	$ 177	$ -	$ 19,132	$ 88
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ 175,000	$ -	$ 737,328	$ 324,977	$ 31,781	$ -	$ 356,758	$ 380,570
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,130,721	-$ 588,100	$ 96,964	-$ 2,621,857	-$ 0	-$ 96,964	$ 96,964	-$ 0	-$ 2,621,857
	etc.										$ -	$ -
		Total		**$ 25,678,601**	**$ 1,795,900**	**-$ 704,138**	**$ 26,770,364**	**$ 13,196,172**	**$ 1,001,018**	**-$ 447,022**	**$ 13,750,169**	**$ 13,020,195**

Table 2.2.5(b): Fixed Asset Continuity Statement – 2013 (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,412,282	$ 896,700	-$ 121,867	$ 6,187,115	$ 1,339,447	$ 155,584	-$ 120,043	$ 1,374,988	$ 4,812,127
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,792,795	$ 353,100	-$ 141,554	$ 5,004,341	$ 2,245,167	$ 76,808	-$ 125,881	$ 2,196,094	$ 2,808,247
47	1835	Overhead Conductors & Devices		$ 2,236,788	$ 99,700	-$ 28,571	$ 2,307,917	$ 1,094,508	$ 26,099	-$ 25,363	$ 1,095,244	$ 1,212,673
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,346,413	$ 16,021	$ -	$ 1,362,434	$ 586,507
47	1845	Underground Conductors & Devices		$ 1,772,824	$ 387,500	$ -	$ 2,160,324	$ 868,206	$ 40,122	$ -	$ 908,329	$ 1,251,995
47	1850	Line Transformers		$ 3,672,084	$ 318,900	-$ 42,010	$ 3,948,974	$ 1,975,176	$ 62,659	-$ 39,772	$ 1,998,063	$ 1,950,911
47	1855	Services (Overhead & Underground)		$ 338,323	$ 30,900	$ -	$ 369,223	$ 30,044	$ 5,676	$ -	$ 35,719	$ 333,503
47	1860	Meters		$ 1,117,459	$ 10,000	-$ 801,102	$ 326,357	$ 739,082	$ 33,914	-$ 543,986	$ 229,011	$ 97,346
47	1860	Meters (Smart Meters)		$ 1,204,471	$ -	$ -	$ 1,204,471	$ 247,938	$ 75,774	$ -	$ 323,712	$ 880,759
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,070,772	$ 25,000	$ -	$ 1,095,772	$ 461,208	$ 16,550	$ -	$ 477,758	$ 618,015
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 231,408	$ 4,357	$ -	$ 235,765	$ 24,259
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 494,483	$ 22,200	$ -	$ 516,683	$ 438,924	$ 22,367	$ -	$ 461,291	$ 55,392
45	1920	Computer Equip.-Hardware(Smart Meters)		$ 18,764	$ -	$ -	$ 18,764	$ 11,132	$ 3,753	$ -	$ 14,885	$ 3,879
52	1925	Software		$ 373,256	$ 55,000	$ -	$ 428,256	$ 324,735	$ 23,911	$ -	$ 348,647	$ 79,610
12	1925	Software (Smart Meters)		$ 68,016	$ -	$ -	$ 68,016	$ 35,435	$ 13,603	$ -	$ 49,038	$ 18,978
10	1930	Transportation Equipment - Large Vehicles		$ 1,011,195	$ -	$ -	$ 1,011,195	$ 278,968	$ 126,399	$ -	$ 405,368	$ 605,828
	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 & Garage Equipment		$ 289,725	$ 10,000	$ -	$ 299,725	$ 219,506	$ 12,961	$ -	$ 232,467	$ 67,257
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,331	$ 300	$ -	$ 132,631	$ 1,479
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,955	$ 177	$ -	$ 19,132	$ 88
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ 175,000	$ -	$ 737,328	$ 314,444	$ 20,422	$ -	$ 334,867	$ 402,461
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,166,197	-$ 588,100	$ 64,211	-$ 2,690,085	$ -	-$ 64,211	$ 64,211	$ -	-$ 2,690,085
	etc.										$ -	$ -
		Total		$ 25,229,022	$ 1,795,900	-$ 1,070,893	$ 25,954,029	$ 12,511,128	$ 682,735	-$ 790,834	$ 12,403,029	$ 13,551,000

Gross Assets Tables:

Table 2.2.6(a): Gross Assets (CGAAP)

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	Variance 2009 Approved to 2009 Actual	2010 Actual	Variance 2009 Actual to 2010 Actual	2011 Actual	Variance 2010 Actual to 2011 Actual	2012 Bridge	Variance 2011 Actual to 2012 Bridge	2013 Test	Variance 2012 Bridge to 2013 Test
	Fixed Assets											
1611	Computer Software (Formally known as Account 1925)		0	0	0	0	0	0	0	0	0	0
1612	Land Rights (Formally known as Account 1906)		0	0	0	0	0	0	32,555	32,555	32,555	0
1805	Land	365,298	381,738	16,440	381,738	0	381,738	0	381,738	0	381,738	0
1806	Land Rights	32,555	32,555	0	32,555	0	32,555	0	0	(32,555)	0	0
	-	0	0	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	4,153,946	2,615,015	(1,538,931)	5,023,306	2,408,291	5,041,733	18,427	5,604,933	563,200	6,501,633	896,700
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	3,962,563	4,039,127	76,564	4,214,995	175,868	4,583,735	368,740	4,907,335	323,600	5,260,435	353,100
1835	Overhead Conductors and Devices	1,888,492	1,849,708	(38,785)	2,049,549	199,841	2,197,671	148,123	2,288,831	91,160	2,388,531	99,700
1840	Underground Conduit	0	0	0	2,092	2,092	3,605	1,514	1,948,941	1,945,336	1,948,941	0
1845	Underground Conductors and Devices	3,132,065	3,059,746	(72,319)	3,262,387	202,641	3,325,660	63,273	1,772,824	(1,552,836)	2,160,324	387,500
1850	Line Transformers	3,247,803	3,120,898	(126,904)	3,346,007	225,109	3,423,353	77,346	3,726,953	303,600	4,045,853	318,900
1855	Services	238,956	167,962	(70,994)	182,968	15,005	304,423	121,455	338,323	33,900	369,223	30,900
1860	Meters	1,040,782	1,044,292	3,510	1,065,646	21,354	1,104,459	38,813	1,117,459	13,000	326,357	(791,102)
1860	Meters (Smart Meters)	0	0	0	0	0	0	0	1,204,471	1,204,471	1,204,471	0
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0	0	0
1905	Land	0	0	0	0	0	0	0		0		0
1908	Buildings and Fixtures	974,699	966,206	(8,493)	984,361	18,155	1,025,772	41,411	1,070,772	45,000	1,095,772	25,000
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0
1915	Office furniture & Equipment (10 years)	246,273	251,230	4,958	259,029	7,799	260,024	995	260,024	0	260,024	0
1915	Office furniture & Equipment (5 years)		0	0	0		0		0	0	0	0
1920	Computer Equipment - Hardware	420,487	430,341	9,854	458,908	28,567	464,983	6,075	494,483	29,500	516,683	22,200
1920	Computer Equip.-Hardware(Smart Meters)		0	0	0		0		18,764	18,764	18,764	0
1920	Computer Software	313,858	305,754	(8,104)	345,754	40,000	363,056	17,303	373,256	10,200	428,256	55,000
1925	Software (Smart Meters)								68,016	68,016	68,016	0
1930	Transportation Equipment - Large Vehicles	1,096,092	1,047,274	(48,818)	1,047,274	0	858,183	(189,091)	1,011,195	153,012	1,011,195	0
1930	Transportation Equipment - Small Vehicles						161,023	161,023	171,823	10,800	171,823	0
1935	Stores Equipment	8,610	8,610	0	8,610	0	8,610	0	8,610	0	8,610	0
1940	Tools, Shop and Garage Equipment	262,199	259,865	(2,335)	266,128	6,263	272,825	6,697	289,725	16,900	299,725	10,000
1945	Measurement and Testing Equipment	2,634	2,634	0	2,634	0	2,634	0	2,634	0	2,634	0
1950	Power Operated Equipment		0	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	131,713	132,253	540	134,110	1,857	134,110	0	134,110	0	134,110	0
1955	Communication Equipment (Smart Meters)		0	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	19,220	19,220	0	19,220	0	19,220	0	19,220	0	19,220	0
	-	0	0	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises		0	0	0	0	0	0		0	0	0
1980	System Supervisory Equipment	365,803	357,012	(8,791)	452,129	95,117	562,328	110,198	562,328	0	737,328	175,000
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property		0	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(985,010)	(1,259,866)	(274,857)	(1,429,952)	(170,086)	(1,621,821)	(191,869)	(2,130,721)	(508,900)	(2,621,857)	(491,136)
2005	Property under Capital Lease											
TOTAL GROSS FIXED ASSETS		20,919,038	18,831,573	(2,087,465)	22,109,446	3,277,873	22,909,879	800,433	25,678,601	2,768,722	26,770,364	1,091,762

Table 2.2.6(b): Gross Assets (MIFRS)

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	Variance 2009 Approved to	2010 Actual	Variance 2009 Actual	2011 Actual	Variance 2010 Actual	2012 Bridge	Variance 2011 Actual	2013 Test	Variance 2012 Bridge
	Fixed Assets											
1611	Computer Software (Formally known as Account 1925)	0	0	0	0	0	0	0	0	0	0	0
1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	32,555	32,555	32,555	0
1805	Land	365,298	381,738	16,440	381,738	0	381,738	0	381,738	0	381,738	0
1806	Land Rights	32,555	32,555	0	32,555	0	32,555	0	0	(32,555)	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50	0	0	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 k	4,153,946	2,615,015	(1,538,931)	5,023,306	2,408,291	5,041,733	18,427	5,412,282	370,549	6,187,115	774,833
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	3,962,563	4,039,127	76,564	4,214,995	175,868	4,583,735	368,740	4,792,795	209,060	5,004,341	211,546
1835	Overhead Conductors and Devices	1,888,492	1,849,708	(38,785)	2,049,549	199,841	2,197,671	148,123	2,236,788	39,117	2,307,917	71,129
1840	Underground Conduit	0	0	0	2,092	2,092	3,605	1,514	1,948,941	1,945,336	1,948,941	0
1845	Underground Conductors and Devices	3,132,065	3,059,746	(72,319)	3,262,387	202,641	3,325,660	63,273	1,772,824	(1,552,836)	2,160,324	387,500
1850	Line Transformers	3,247,803	3,120,898	(126,904)	3,346,007	225,109	3,423,353	77,346	3,672,084	248,731	3,948,974	276,890
1855	Services	238,956	167,962	(70,994)	182,968	15,005	304,423	121,455	338,323	33,900	369,223	30,900
1860	Meters	1,040,782	1,044,292	3,510	1,065,646	21,354	1,104,459	38,813	1,117,459	13,000	326,357	(791,102)
1860	Meters (Smart Meters)	0	0	0	0	0	0	0	1,204,471	1,204,471	1,204,471	0
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0	0	0
1905	Land	0	0	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	974,699	966,206	(8,493)	984,361	18,155	1,025,772	41,411	1,070,772	45,000	1,095,772	25,000
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0
1915	Office furniture & Equipment (10 years)	246,273	251,230	4,958	259,029	7,799	260,024	995	260,024	0	260,024	0
1915	Office furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0
1920	Computer Equipment - Hardware	420,487	430,341	9,854	458,908	28,567	464,983	6,075	494,483	29,500	516,683	22,200
1920	Computer Equip.-Hardware(Smart Meters)	0	0	0	0	0	0	0	18,764	18,764	18,764	0
1920	Computer Software	313,858	305,754	(8,104)	345,754	40,000	363,056	17,303	373,256	10,200	428,256	55,000
1925	Software (Smart Meters)	0	0	0	0	0	0	0	68,016	68,016	68,016	0
1930	Transportation Equipment - Large Vehicles	1,096,092	1,047,274	(48,818)	1,047,274	0	858,183	(189,091)	1,011,195	153,012	1,011,195	0
1930	Transportation Equipment - Small Vehicles	0	0	0	0	0	161,023	161,023	171,823	10,800	171,823	0
1935	Stores Equipment	8,610	8,610	0	8,610	0	8,610	0	8,610	0	8,610	0
1940	Tools, Shop and Garage Equipment	262,199	259,865	(2,335)	266,128	6,263	272,825	6,697	289,725	16,900	299,725	10,000
1945	Measurement and Testing Equipment	2,634	2,634	0	2,634	0	2,634	0	2,634	0	2,634	0
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	131,713	132,253	540	134,110	1,857	134,110	0	134,110	0	134,110	0
1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	19,220	19,220	0	19,220	0	19,220	0	19,220	0	19,220	0
0	0	0	0	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	365,803	357,012	(8,791)	452,129	95,117	562,328	110,198	562,328	0	737,328	175,000
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	(985,010)	(1,259,866)	(274,857)	(1,429,952)	(170,086)	(1,621,821)	(191,869)	(2,166,197)	(544,376)	(2,690,085)	(523,889)
2005	Property under Capital Lease											
TOTAL GROSS FIXED ASSETS		**20,919,038**	**18,831,573**	**(2,087,465)**	**22,109,446**	**3,277,873**	**22,909,879**	**800,433**	**25,229,022**	**2,319,143**	**25,954,029**	**725,007**

Variance Analysis on Gross Assets:

The Gross Asset Variance analysis for the variances highlighted in Table 2.2.6(a) and Table 2.2.6(b) of Exhibit 2, Tab 2, Schedule 2 is provided as follows:

<u>2009 Board Approved vs. 2009 Actual</u>

The opening balance in 2009 in accordance with the 2009 COS Application was approximately $200,000 higher than the actual 2008 ending balance due to less spending in 2008 than what was forecast.

The 2009 Board Approved Fixed Asset value was based on the completion of the Fourth Street substation project in 2009 at a budget cost of $1,262,800. Although substantially all the costs ($1,072,257) for the project were paid in 2009, energization of the substation did not occur until early 2010. Consequently, the in service date did not occur until the substation was energized. The costs incurred were recorded in account #2055 Construction WIP for the year 2009 and were transferred to the asset base account #1820 in 2010. This reduced spending in 2009 by $190,273. Additional costs were incurred in 2010 for this project in the amount of $179,886 for a total project cost of $1,252,413. Amortization on the substation did not occur until 2010.

The reduced capital spending was also as a result of an adjustment made to the 2008 capital of $230,000 for work accrued in 2008 which was not completed in 2009. In addition, development contributions were paid in 2009 but not included in the 2009 COS Application in the amount of $116,132. The Bourgeois Lane Kiosk project was not completed in 2009 totaling $159,200, however, additional projects were done throughout the year.

Transportation Equipment purchases were $48,800 less than what was budgeted due to the removal of a trailer in the 2008 vehicle assets of $22,345 and the removal of the vehicle replaced in 2009 of $23,700.

2009 Actual vs. 2010 Actual

The variances in gross assets for 2009 Actual compared to 2010 Actual are the result of capital expenditures in 2010, and disposal of a generator (USoA Account #1908 in the amount of $5,442) during the year. The energization of the Fourth Street Substation in early 2010 accounted for approximately $1,200,000 of the additions in 2010 as the values were transferred from WIP to fixed assets.

2010 Actual vs. 2011 Actual

The variances in gross assets for 2010 Actual compared to 2011 Actual are the result of capital expenditures in 2011 and the disposal of a vehicle ($30,492) and a mailing machine ($15,524) in 2011.

2011 Actual vs .2012 Bridge Year (CGAAP)

The variances in gross assets for 2011 Actual compared to 2012 Bridge Year are the result of capital expenditures in 2012 and the disposal of two vehicles ($372,388) during the year. In addition, smart meter capital costs have been recorded as capital assets in 2012. Midland PUC submitted its Application to the OEB under EB -2011-0434 for disposition and recovery of costs related to smart meter deployment. The OEB's Decision and Order on May 3, 2012 approved the disposition for recovery of costs for smart meter deployment and operation. Midland PUC was ordered to record the capital and operating expenses accounts as is the case with other regular distribution assets and costs.

<u>2012 Bridge Year (CGAAP) vs. 2013 Test Year (CGAAP)</u>

The variances in gross assets for the 2012 Bridge Year compared to the 2013 Test Year are the result of capital expenditures in 2013 (total capital expenditures in 2013 - $1,795,900). Stranded meter assets in the amount of $801,000 were disposed of in the year.

<u>2011 Actual vs .2012 Bridge Year (MIFRS)</u>

The variances in gross assets for 2011 Actual compared to 2012 Bridge Year are the result of capital expenditures in 2012, the disposal of two vehicles ($372,388) during the year and the disposal of pole line and substation related distribution assets totaling approximately $414,000 under MIFRS asset recognition. In addition, smart meter capital costs have been recorded as capital assets in 2012. Midland PUC submitted its Application to the OEB under EB -2011-0434 for disposition and recovery of costs related to smart meter deployment. The OEB's Decision and Order on May 3, 2012 approved the disposition for recovery of costs for smart meter deployment and operation. Midland PUC was ordered to record the capital and operating expenses accounts as is the case with other regular distribution assets and costs.

<u>2012 Bridge Year (CGAAP) vs. 2013 Test Year (CGAAP)</u>

The variances in gross assets for the 2012 Bridge Year compared to the 2013 Test Year are the result of capital expenditures in 2013 (total capital expenditures in 2013 - $1,795,900). Stranded meter assets in the amount of $801,000 were disposed of in the year. In addition, pole line and substation related distribution assets totaling approximately $334,000 were disposed of under MIFRS asset recognition.

1 **Accumulated Amortization Table:**

Table 2.2.7(a) - Accumulated Amortization (CGAAP)

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	Variance 2009 Approved to 2009 Actual	2010 Actual	Variance 2009 Actual to 2010 Actual	2011 Actual	Variance 2010 Actual to 2011 Actual	2012 Bridge	Variance 2011 Actual to 2012 Bridge	2013 Test	Variance 2012 Bridge to 2013 Test
	Fixed Assets											
1611	Computer Software (Formally known as Account 1925)		0	0	0	0	0	0	0	0	0	0
1612	Land Rights (Formally known as Account 1906)		0	0	0	0	0	0	15,060	15,060	15,060	0
1805	Land		0	0	0	0	0	0	0	0	0	0
1806	Land Rights	15,060	15,060	0	15,060	0	15,060	0	0	(15,060)	0	0
0	0		0	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV		0	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1,068,476	1,016,431	(52,044)	1,151,157	134,726	1,334,736	183,578	1,529,649	194,913	1,753,760	224,111
1825	Storage Battery Equipment		0	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1,843,100	2,016,968	173,868	2,139,983	123,015	2,276,158	136,175	2,413,449	137,291	2,560,287	146,838
1835	Overhead Conductors and Devices	1,153,508	993,529	(159,980)	1,054,126	60,598	1,121,197	67,071	1,188,818	67,621	1,261,141	72,323
1840	Underground Conduit	0	0	0	0	0	0	0	1,403,222	1,403,222	1,475,205	71,983
1845	Underground Conductors and Devices	1,927,017	1,925,543	(1,475)	2,046,110	120,568	2,168,226	122,116	883,700	(1,284,526)	929,032	45,333
1850	Line Transformers	1,736,935	1,745,372	8,437	1,856,434	111,062	1,970,928	114,494	2,085,558	114,630	2,202,837	117,279
1855	Services	15,330	5,425	(9,906)	12,387	6,962	25,029	12,642	37,826	12,797	51,919	14,093
1860	Meters	629,428	629,876	448	666,264	36,388	703,094	36,831	739,082	35,988	229,011	(510,072)
1860	Meters (Smart Meters)		0	0	0	0	0	0	251,861	251,861	331,558	79,697
1865	Other Installations on Customer's Premises		0	0	0	0	0	0	0	0	0	0
1905	Land		0	0	0	0	0	0		0		0
1908	Buildings and Fixtures	380,129	380,049	(81)	411,026	30,978	444,415	33,389	479,836	35,421	517,007	37,171
1910	Leasehold Improvements		0	0	0	0	0	0	0	0	0	0
1915	Office furniture & Equipment (10 years)	221,846	222,236	390	228,700	6,464	226,029	(2,672)	233,528	7,499	240,094	6,566
1915	Office furniture & Equipment (5 years)		0	0	0	0	0	0	0	0	0	0
1920	Computer Equipment - Hardware	384,206	384,576	370	400,856	16,280	419,275	18,419	438,924	19,649	459,071	20,147
1920	Computer Equip.-Hardware(Smart Meters)		0	0	0	0	0	0	11,132	11,132	17,105	5,973
1920	Computer Software	200,052	196,978	(3,074)	244,118	47,140	292,447	48,329	324,735	32,289	348,647	23,911
1925	Software (Smart Meters)								35,435	35,435	49,038	13,603
1930	Transportation Equipment - Large Vehicles	464,046	418,871	(45,175)	527,261	108,389	482,962	(44,298)	278,968	(203,994)	405,368	126,399
1930	Transportation Equipment - Small Vehicles						122,196	122,196	138,376	16,180	151,797	13,421
1935	Stores Equipment	8,610	8,610	0	8,610	0	8,610	0	8,610	0	8,610	0
1940	Tools, Shop and Garage Equipment	250,997	187,449	(63,548)	197,367	9,918	207,890	10,523	219,506	11,616	232,467	12,961
1945	Measurement and Testing Equipment	0	2,634	2,634	2,634	0	2,634	0	2,634	0	2,634	0
1950	Power Operated Equipment		0	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	84,655	130,207	45,552	131,731	1,524	132,031	300	132,331	300	132,631	300
1955	Communication Equipment (Smart Meters)		0	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	3,698	18,078	14,380	18,601	523	18,778	177	18,955	177	19,132	177
0	0		0	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises		0	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	249,676	248,799	(877)	270,652	21,853	298,397	27,745	324,977	26,580	356,758	31,781
1985	Sentinel Lighting Rentals		0	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property		0	0	0	0	0	0	(0)	(0)	0	0
1995	Contributions and Grants		0	0	0	0	0	0	0	0	(0)	(0)
2005	Property under Capital Lease		0	0	0	0	0	0	0	0	0	0
TOTAL GROSS FIXED ASSETS		**10,636,770**	**10,546,691**	**(90,079)**	**11,383,077**	**836,386**	**12,270,092**	**887,016**	**13,196,172**	**926,080**	**13,750,169**	**553,997**

Table 2.2.7(b) - Accumulated Amortization (MIFRS)

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	Variance 2009 Approved to 2009 Actual	2010 Actual	Variance 2009 Actual to 2010	2011 Actual	Variance 2010 Actual to 2011	2012 Bridge (MIFRS)	Variance 2011 Actual to 2012	2013 Test (MIFRS)	Variance 2012 Bridge to 2013 Test
	Fixed Assets											
1611	Computer Software (Formally known as Account 1925)	0	0	0	0	0	0	0	0	0	0	0
1612	Land Rights (Formally known as Account 1906)	0	0	0	0	0	0	0	15,060	15,060	15,060	0
1805	Land	0	0	0	0	0	0	0	0	0	0	0
1806	Land Rights	15,060	15,060	0	15,060	0	15,060	0	0	(15,060)	0	0
		0	0	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	0	0	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1,068,476	1,016,431	(52,044)	1,151,157	134,726	1,334,736	183,578	1,339,447	4,711	1,374,988	35,541
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1,843,100	2,016,968	173,868	2,139,983	123,015	2,276,158	136,175	2,245,167	(30,992)	2,196,094	(49,073)
1835	Overhead Conductors and Devices	1,153,508	993,529	(159,980)	1,054,126	60,598	1,121,197	67,071	1,094,508	(26,689)	1,095,244	736
1840	Underground Conduit	0	0	0	0	0	0	0	1,346,413	1,346,413	1,362,434	16,021
1845	Underground Conductors and Devices	1,927,017	1,925,543	(1,475)	2,046,110	120,568	2,168,226	122,116	868,206	(1,300,020)	908,329	40,122
1850	Line Transformers	1,736,935	1,745,372	8,437	1,856,434	111,062	1,970,928	114,494	1,975,176	4,248	1,998,063	22,887
1855	Services	15,330	5,425	(9,906)	12,387	6,962	25,029	12,642	30,044	5,015	35,719	5,676
1860	Meters	629,428	629,876	448	666,264	36,388	703,094	36,831	739,082	35,988	229,011	(510,072)
1860	Meters (Smart Meters)	0	0	0	0	0	0	0	247,938	247,938	323,712	75,774
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0	0	0
1905	Land	0	0	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	380,129	380,049	(81)	411,026	30,978	444,415	33,389	461,208	16,792	477,758	16,550
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0
1915	Office furniture & Equipment (10 years)	221,846	222,236	390	228,700	6,464	226,029	(2,672)	231,408	5,379	235,765	4,357
1915	Office furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0
1920	Computer Equipment - Hardware	384,206	384,576	370	400,856	16,280	419,275	18,419	438,924	19,649	461,291	22,367
1920	Computer Equip.-Hardware(Smart Meters)	0	0	0	0	0	0	0	11,132	11,132	14,885	3,753
1920	Computer Software	200,052	196,978	(3,074)	244,118	47,140	292,447	48,329	324,735	32,289	348,647	23,911
1925	Software (Smart Meters)	0	0	0	0	0	0	0	35,435	35,435	49,038	13,603
1930	Transportation Equipment - Large Vehicles	464,046	418,871	(45,175)	527,261	108,389	482,962	(44,298)	278,968	(203,994)	405,368	126,399
1930	Transportation Equipment - Small Vehicles	0	0	0	0	0	122,196	122,196	131,797	9,601	141,283	9,487
1935	Stores Equipment	8,610	8,610	0	8,610	0	8,610	0	8,610	0	8,610	0
1940	Tools, Shop and Garage Equipment	250,997	187,449	(63,548)	197,367	9,918	207,890	10,523	219,506	11,616	232,467	12,961
1945	Measurement and Testing Equipment	0	2,634	2,634	2,634	0	2,634	0	2,634	0	2,634	0
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	84,655	130,207	45,552	131,731	1,524	132,031	300	132,331	300	132,631	300
1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	3,698	18,078	14,380	18,601	523	18,778	177	18,955	177	19,132	177
		0	0	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	249,676	248,799	(877)	270,652	21,853	298,397	27,745	314,444	16,047	334,867	20,422
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	0	0	0	0	0	0	0	0	0	0	0
2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0	0	0
TOTAL GROSS FIXED ASSETS		**10,636,770**	**10,546,691**	**(90,079)**	**11,383,077**	**836,386**	**12,270,092**	**887,016**	**12,511,128**	**241,035**	**12,403,029**	**(108,099)**

Variance Analysis on Accumulated Amortization:

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identified assets.

Table 2.2.7(a) shows the changes in accumulated amortization from 2009 Actual to the 2013 Test Year under CGAAP. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, and write-offs of fully-amortized assets as appropriate over the four year period. Stranded meters have been disposed of in 2013 resulting in a decrease to accumulated amortization of $543,986. Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

Table 2.2.7(b) shows the changes in accumulated amortization from 2009 Actual to the 2013 Test Year under MIFRS. The change in accumulated amortization is a result of capital expenditures, amortization expense each year, write-offs of fully-amortized assets and disposals as appropriate over the four year period. Stranded meters have been disposed of in 2013 resulting in a decrease to accumulated amortization of $543,986. Amortization expense has decreased in 2012 and 2013 to reflect increase in the useful lives of the assets in accordance with the Asset Depreciation Study dated July 8, 2010. Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

CAPITAL BUDGET:

Introduction:

Midland PUC's Asset Management Plan identifies the capital projects required based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, Midland PUC may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of Midland PUC's capital investments are driven by the Load Study and Asset Management Plan referred to in Appendices A and B. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year will be completed and in service in that year.

Midland PUC has provided explanations to address its actual capital investments for the years 2009 to 2011 and has provided details in support of its 2012 Bridge Year and 2013 Test Year capital and working capital requirements as required in the Filing Requirements.

Midland PUC submits one of the main drivers of capital investments since 2007 has been the replacement of its substations which are well over 50 years of age. In addition, investments in pole line reconstruction and other infrastructure are required to ensure the distribution system remains stable and safe. Midland PUC further submits that its forecasted capital investments for the 2012 Bridge Year and 2013 Test Year are consistent with the required investments of prior years and are prudent and just in supporting the continued growth in the Town of Midland and the continued safety and reliability of its distribution system.

Midland PUC has an obligation to serve new growth within our service area in a timely and cost effective way. In order to fulfill this obligation, Midland PUC identifies all potential areas where new growth may occur, while recognizing that the actual timing of each possible new development is uncertain. This is the prudent approach to planning since it ensures that we are ready to accommodate the most extreme demands we may face. Nevertheless, we recognize it is unlikely all of the plans developers have in our service area will proceed as quickly as expected. Our capital budget reflects the level of growth we anticipate based on the overall rate of development in our service area in recent years, anticipated economic conditions and management judgment. Given the uncertainty of development in our area, our plans are updated regularly to ensure that they reflect the most current plans of developers.

All projects, except for the Development Contribution Project, are considered renewals. The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, it is estimated Midland PUC will pay a transfer price of for the assets installed by the developer.

Midland PUC has a vehicle replacement plan for the replacement of its rolling stock. In addition, assessments are done on the vehicles each year to ensure that the plan is kept up to date. The strategic vehicle replacement program will replace aging vehicles in an even fashion avoiding sudden increases in capital acquisitions. Midland PUC's vehicle replacement process considers the following criteria:

Vehicle operational condition;
Vehicle safety;
Mileage; age; engine hours;
Department needs; and
Replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

The vehicle replacement program is based on annual condition surveys and life cycle planning. New vehicles and equipment support productivity through innovation, improve crew response time, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Each year Midland PUC looks at other plant, equipment and vehicles, along with the distribution system and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of Midland PUC's distribution system are made.

Midland PUC has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending by project category for the years 2007 to 2013 is provided in Table 2.3.1 (a) below. Table 2.3.1(b) provides a summary of these detailed capital projects.

Details of Midland PUC's actual capital expenditures in comparison to budget for the years 2009, 2010 and 2011 are provided in Tables 2.3.2 to 2.3.7. Details of Midland PUC's capital budget for the 2012 Bridge Year and 2013 Test year are provided in Tables 2.3.8 to 2.3.11. Exhibit 2, Tab 3, Schedule 2 provides details of these capital projects by USoA and by project.

Table 2.3.1(a) – Capital Spending by Project Category 2007 to 2013

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Substation Projects						**& CGAAP**	
Scott/Brandon	743,693	1,322,652					
Project 1: Fourth St Substation			1,072,527	179,886			
Project 5: Montreal Substation			59,179				
Project 6: Brandon St Substation			-230,007				
Project 2: Dorion St Substation				1,178,364			
Project 1: Montreal St Substation						563,200	
Project 1: Queen St Substation							896,700
Sub-Total	**743,693**	**1,322,652**	**901,699**	**1,358,250**	**0**	**563,200**	**896,700**
Pole Line Projects							
Pole Line construction	235,703	404,611					
Project 2: Yonge St Pole Line			246,173				
Project 3: Sunnyside Pole Line			88,237				
Project 4: Miscellaneous Pole Replacements			52,076				
Project 4: Hugel Ave Pole Line				120,003			
Project 7: Tornado Rebuild				127,659			
Project 1: Gloucester Pole Line					56,552		
Project 2: Bay St Pole Line					95,559		
Project 3: Albert St Pole Line					65,742		
Project 4: Pole Replacements Misc					70,326		
Project 6: Tornado Rebuild					228,215		
Project 2: William St. North Pole Line						150,760	
Project 3: Pratt's Field Pole Line						71,400	
Project 4: Selected Pole Replacements						84,100	
Project 2: William St. South Pole Line							162,900
Project 3: Fourth St Pole Line							117,600
Project 4: Selected Pole Replacements							84,100
Sub-Total	**235,703**	**404,611**	**386,487**	**247,661**	**516,394**	**306,260**	**364,600**
Transformers							
Pad Mount and Pole Top	48,817	106,438		54,059		87,200	87,200
Project 3: Bourgeois Lane Kiosk				79,275			
Sub-Total	**48,817**	**106,438**	**0**	**133,334**	**0**	**87,200**	**87,200**
Economic Evaluations - System Expansions							
Economic Evaluations - System Expansions			116,132	35,272	-141,484	107,000	100,000
Sub-Total	**0**	**0**	**116,132**	**35,272**	**-141,484**	**107,000**	100,000
Vehicles							
Large and Small Trucks	151,987	43,925					
Project 9: Truck Purchase			377,620				
Project 9: Vehicles						536,200	
Sub-Total	**151,987**	**43,925**	**377,620**	**0**	**0**	**536,200**	**0**
Software/Hardware							
CIS System	142,024						
Project 5: Mapping & Asset Management				107,668	110,198		
Project 8: Scada							187,265
Project 9: Harris CIS Upgrade							55,000
Sub-Total	**142,024**	**0**	**0**	**107,668**	**110,198**	**0**	**242,265**
Metering Infrastructure							
Project 7: Smart Meter Infrastructure Implementation						1,291,251	
Sub-Total	**0**	**0**	**0**	**0**	**0**	**1,291,251**	**0**
Miscellaneous	**129,612**	**111,957**	**246,809**	**264,601**	**289,747**	**164,800**	**105,100**
Total	**1,451,837**	**1,989,583**	**2,028,746**	**2,146,787**	**774,855**	**3,055,911**	**1,795,865**

Table 2.3.1(b) – Capital Spending Summary 2007 to 2013

Year	Total Distribution Plant	Capital Contributions	Net Distribution Plant	General Plant	Total Capital net of Contributions	$ increase / (decrease)	% increase / (decrease)
2007	1,278,891	(218,797)	1,060,094	391,743	1,451,837		
2008	2,176,611	(299,742)	1,876,868	132,087	2,008,955	557,118	38%
2009 COS	2,623,800	(273,500)	2,350,300	470,100	2,820,400	811,445	40%
2009	1,004,480	(523,731)	480,749	475,471	956,220	(1,864,180)	-66%
2010**	3,250,200	(234,087)	3,016,113	203,200	3,219,313	2,263,093	237%
2011	840,098	(265,869)	574,228	200,627	774,856	(2,444,458)	-76%
2012	2,925,431	(594,100)	2,331,331	724,580	3,055,911	2,281,055	294%
2013	2,096,800	(588,100)	1,508,700	287,200	1,795,900	(1,260,011)	-41%

** 2010 includes $1,072,527 spending for the Fourth St substation which was considered WIP at the end of 2009

The updated filing requirements for Exhibit 2 (Rate Base) request actual historical summary information for the last 5 years. Note that 2007 and 2008 expenditures are presented for informational purposes only and will not be discussed in detail in this application.

In 2009, the main driver of the decrease of 66% was due to the recognition of the Fourth Street Substation project as Work in Progress (WIP) in 2009. This project was slated to be in service in 2009. Although $1,072,527 was spent in 2009, the station was put into service in early 2010. The reduced capital spending was also as a result of an adjustment made to the 2008 capital of $230,000 for work accrued in 2008 which was not completed in 2009. In addition, development contributions included in the 2009 Board Approved of approximately $300,000 were not paid as development did not occur. Contributions and Grants exceeded Board Approved amounts by $250,000. Transportation Equipment purchases were $48,800 less than what was budgeted due to the removal of a trailer in the 2008 vehicle assets of $22,345 and the removal of the vehicle replaced in 2009 of $23,700.

In 2010, the main driver of the increase of 237% over 2009 spending levels was the transfer of the $1,072,527 for the Fourth Street Substation from WIP to fixed assets. Midland PUC also completed the Dorion Substation project at a cost of $1,178,364. These two projects represent $2,430,776 of spending (Fourth St: $1072,527 in 2009 and $179,886 in 2010 = $1,252, 413 plus Dorion Substation $1,178,364). 2010 General Plant additions decreased over 2009 mainly due to the addition of a new truck in 2009. Midland PUC's spending in 2010 included approximately one half of the cost ($107,668) of the Asset Management Plan. In addition, on June 23, 2010 an F2 Tornado with peak speeds of 180 to 240 km/h struck Midland. Extensive damage was done to Midland PUC's distribution system resulting in fixed asset replacements.

In 2011, Midland PUC's capital expenditures reduced significantly. No substation upgrades were completed in 2011, however, other distribution and general plant upgrades remained constant with 2010. Midland PUC's spending in 2011 also included the balance of the cost of the Asset Management Plan ($110,198) and the balance of the fixed asset costs relating to the tornado in 2010.

For 2012, an increase in spending is forecast as Midland PUC's completes the upgrade to the Montreal Substation at a projected cost of $563,200. Midland PUC is planning a number of projects to update its aging infrastructure totaling $844,700. Midland PUC will be replacing two trucks in 2012 at a cost of $536,200. In 2012, Midland PUC completed its prudence review of smart meter infrastructure under EB-2011-0434. Assets and associated amortization values have been recorded in fixed assets in 2012.

In 2013, Midland PUC is planning to complete the upgrade of the last substation (Queen St) at a cost of $896,700. A number of projects to upgrade the aging infrastructure are planned totaling $906,100. Spending over the 2013 in General Plant will be reduced significantly. No fleet additions are expected, however, $175,000 has been included for the installation of a SCADA system.

Exhibit 2, Tab 3, Schedule 2 provides details of all projects.

The capital spending numbers reported above in Table 2.3.1 include all amounts relating to the smart meter infrastructure. The capital spending in Table 2.3.1 are exclusive of spending required to meet the needs of the Green Energy Act. As discussed in our Green Energy Plan, Midland does not anticipate incurring additional capital expenditures relating to the provisions of the Green Energy Act. These expenses are discussed as part of Midland PUC's Green Energy Plan which can be found in Exhibit 2, Appendix C.

Provincial Sales Tax Impact

As a result of the implementation of HST in the province of Ontario on July 1, 2010, Midland PUC has considered the reduction in capital expenditures relating to the purchase of products and services due to the increased input tax credit (ITC). Neither the 2012 Bridge Year forecast nor the 2013 Test Year budget for capital expenditures includes tax on purchases of products or services made after July 1, 2010.

CAPITAL PROJECTS BY YEAR AND USoA

The tables below summarize Midland PUC's actual investment in construction projects vs. OEB 2009 Approved and Midland PUC Board Approved for the years 2009, 2010, 2011. Midland PUC has summarized the projects for the 2012 Bridge Year and 2013 Test Year. Project descriptions are also provided.

Table 2.3.2 - 2009 Capital Projects

USoA #	Description	CCA Class	Project 1: Fourth St Substation	Project 2: Yonge St Pole Line	Project 3: Sunnyside Pole Line	Project 4: Miscellaneous Pole Replacements	Project 5: Montreal Substation	Project 6: Brandon St Substation	Project 7: Economic Evaluations - System Expansions	Project 8: - Upgrades & New Customer Additions	Project 9: Truck Purchase	Project 10: Miscellaneous Capital Projects	2009 COS Project - Bourgeois Lane Kiosk	Total
1805	Land	N/A										$ 16,440		$ 16,440
1806	Land Rights	CEC										$ -		$ -
1808	Land and Buildings	47										$ -		$ -
1810	Leasehold Improvements	13										$ -		$ -
1815	Transformer Station Equipment - Normally > 50 kV	47										$ -		$ -
1820	Distribution Station Equipment - Normally < 50 kV	47	$ 1,055,336			$ -	$ 58,594	$ 1,251				$ 21,504		$ 1,136,685
1830	Poles, Towers, Fixtures	47	$ 8,396	$ 195,500	$ 81,327	$ 20,848	$ 586	$ 236		$ 107,269		$ 27,872		$ 442,034
1835	Overhead Conductors & Devices	47		$ 28,992	$ 6,910	$ 7,351	$ -	-$ 232,021		$ 78,538		$ 9,739		-$ 100,491
1845	Underground Conductor & Devices	47	$ 8,795	$ 580		$ 12,239			$ 228,900	$ 42,966		$ 17,847		$ 311,327
1850	Line Transformers	47		$ 21,102		$ 19,591			$ 70,000	$ 49,573		$ 45,071		$ 205,337
1855	Services	47						$ 526	$ 50,000	$ 4,663		$ 6,394		$ 61,583
1860	Meters	47										$ 4,092		$ 4,092
1908	Building & Fixtures	47										$ 23,865		$ 23,865
1915	Office Furniture & Equipment	8										$ 2,087		$ 2,087
1920	Computer Equipment - Hardware	10										$ 31,529		$ 31,529
1925	Computer Software	12										$ 23,218		$ 23,218
1930	Vehicle	10									$ 377,620	$ -		$ 377,620
1935	Stores Equipment	8										$ -		$ -
1940	Tools, Shop & Garage Equipment	8										$ 17,153		$ 17,153
1955	Communications Equipment	8										$ -		$ -
1980	System Supervisory Equipment	47										$ -		$ -
														$ -
														$ -
														$ -
1995	Contributions and Grants - Credit					-$ 7,954			-$ 232,768	-$ 283,010				-$ 523,731
	Total Actual Capital Expenditures		**$ 1,072,527**	**$ 246,173**	**$ 88,237**	**$ 52,076**	**$ 59,179**	**-$ 230,007**	**$ 116,132**	**$ -**	**$ 377,620**	**$ 246,809**	**$ -**	**$ 2,028,746**
	OEB 2009 Approved Expenditures		**$ 1,262,800**	**$ 177,300**	**$ 107,900**	**$ 63,100**	**$ -**	**$ -**	**$ 400,000**	**$ 0**	**$ 386,500**	**$ 263,600**	**$ 159,200**	**$ 2,820,400**
	Variance		**-$ 190,273**	**$ 68,873**	**-$ 19,663**	**-$ 11,024**	**$ 59,179**	**-$ 230,007**	**-$ 283,868**	**-$ 0**	**-$ 8,880**	**-$ 16,791**	**-$ 159,200**	**-$ 791,654**

DISTRIBUTION PLANT PROJECTS

2009 Project 1: Fourth St Substation

Need: In 2006, Midland PUC completed a substation study that provided an analysis of existing infrastructure and a plan for the replacement taking into consideration potential future growth in our distribution territory. Midland PUC's distribution system includes six substations. The Fourth Street Substation was built in 1954 and is in need of replacement. The substation was located in the middle of an office building. This substation upgrade was required to enable Midland PUC to serve customers without putting safety and reliability at risk. If substation upgrades are delayed, Midland PUC will be faced with multiple infrastructure replacements at the same time, or in emergency situations cost increases would result due to the nature of the emergency.

Scope: The Fourth Street Substation was the third of six substations to be upgraded. The project included:

Transformer Replacement:

The transformer replacement included the manpower, equipment, transportation and disposal of the existing 3000 Kva transformer, and the installation of the 5000 Kva transformer. The increase to a 5.0 Mva power transformer is necessary for future electric demand.

Secondary Switchgear Replacement:

This part of the upgrade includes the supply and installation of four 5 Kv-3000 Amp breaker cells, supply and installation of one 2000 amp main breaker & four 1200 amp feeder breakers, and the supply and installation of four underground feeders.

Relay Protection Upgrade:
The existing relays were replaced with four Schweitzer protection & breaker control relays.

Additional costs included:
Building construction to house the transformer and equipment
Removal of old substation
Midland PUC Switching and feeder installation.
SCADA Commissioning.
Installation of stone.

As the substations age, it is becoming harder and harder to obtain replacement parts should a substation require repair. As part of our replacement plan, Midland PUC will retain parts that are in a good state of repair from the abandoned stations to provide inventory should one of the existing stations require maintenance.

Prior to the replacement of the substations, engineering studies are completed to support equipment selection; protection co-ordination study, short circuit analysis, ground grid study and an equipment evaluation study. The protection co-ordination study and short circuit analysis were required as part of the equipment evaluation process. The ground grid study is performed before and after the substation is completed.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equipment	$1,055,336
#1830 – Poles, Towers & Fixtures	$ 8,396
#1835 – Overhead Conductors & Devices	$ 8,795
Total Project Cost	$1,072,527

Consultants were hired for project management, engineering and drafting etc. The project was planned and purchase orders issued as required. A security deposit of $74,980 was required by the manufacturer and included with the purchase order.

The building upgrades included construction of washroom facilities ($24,795) security cameras ($12,897) and HVAC upgrades ($19,434). Project management ($39,692).

Budget Comparison:

This project was completed in 2010 at a total cost of $1,257,627, $5,214 below budget. This project is shown as WIP in the year 2009, but spending is included in the 2009 budget year.

Start Date: 2009

In-Service Date: 2010

2009 Project 2: Yonge Street Pole Line - Renewal

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects with some being damaged due to snow plowing operations and other vehicle mishaps.

Scope: 75 poles from County Road 93 to First Street were replaced. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring were replaced. Existing transformer loading was calculated and rebalanced as required. New transformers were installed where required.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 195,500
#1835 – Overhead Conductors & Devices	$ 28,992
#1845 – Underground Conductor & Devices	$ 580
#1850 – Line Transformers	$ 21,102
Total Project Cost	$ 246,173

Budget Comparison:

The project costs were $68,873 over budget, mainly due to the expansion of the project from 49 pole replacements to 75 pole replacements.

Start Date: 2009

In-Service Date: 2009

2009 Project 3: Sunnyside Pole Pole Line – Renewal/Capacity

Need: A new 4.16/2.4 Kv distribution pole line is required to provide capacity to future development within the Town of Midland along the harbor and marina.

Scope: The pole line will be built to accommodate three feeders. 25 poles will be installed. Two circuits will be constructed with the ability to add a third circuit as development demands.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 81,327
#1835 – Overhead Conductors & Devices	$ 6,910
Total Project Cost	$ 88,237

Budget Comparison:

This project came in less than budget by $19,663. Actual labour hours were substantially reduced due to the use of a hydrovac machine for the excavation of the pole placements, rather than manual labour.

Start Date: 2009

In-Service Date: 2009

2009 Project : Miscellaneous Pole Replacements - Renewal

Need: Deteriorated poles at the end of their useful life were replaced before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. The poles replaced were identified as high priority.

Scope: 39 poles were identified and replaced. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring were replaced as required. Existing transformer loading was calculated and rebalanced as required.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 20,848
#1835 – Overhead Conductors & Devices	$ 7,351
#1845 – Underground Conductor & Devices	$ 12,239
#1850 – Line Transformers	$ 19,591
#1995 – Contributions and Grants	-$ 7,954
Total Project Cost	$ 52,076

Budget Comparison:

Midland PUC received contributions of $7,954 for this project which were not taken into account at the time the budget was fixed.

Start Date: 2009

In-Service Date: 2009

2009 Project 5: Montreal Substation

Need: In November, 2009 the Montreal Substation failed requiring replacement of underground wiring.

Scope: New underground copper wire was installed. Loading was shifted to alternate stations while the work was performed.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equipment	$58,594
#1830 – Poles, Towers & Fixtures	$ 586
Total Project Cost	$59,179

Budget Comparison:

This project was an emergency replacement, not taken into account at the time the budget was fixed.

Start Date: 2009

In-Service Date: 2009

2009 Project 6: Brandon Street Substation

In 2008, the Brandon Substation project was completed. This project replaced a 50 plus year old substation. Additional project costs totaling $2,013 were required in 2009. The total project costs for the substation were recorded, by the, then Operations Manager in 2008 as $1,282,190 when in fact, they should have been recorded as $1,052,183 a difference of $232,021. As part of this project, funds were paid to a contractor to be used to construct a pole line adjacent to the substation in 2009. This pole line project was not a part of the Brandon Substation project and was not approved for completion by Midland PUC's Management or Board of Directors. Identification of this erroneous recording was made in the late spring of 2009 and the funds were returned to Midland PUC by the contractor. Midland PUC has made the corrections to the USofA accounts as follows:

Capital Costs:

Acct # & Description	**Amount**
#1820 – Distribution System Equip	$ 1,251
#1830 – Poles, Towers & Fixtures	$ 236
#1835 – Overhead Conductors & Devices	-$ 232,021
#1855 – Services	$ 526
Total Project Cost	-$ 230,007

2009 Project 7: Development Contributions - Economic Evaluations – Customer Demand

Need: The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, Midland PUC records the assets and the offsetting contributed capital.

Scope: In 2009, development contributions totaled $232,768, for the Riverwalk Green development.

Capital Costs:

Acct # & Description	**Amount**
#1845 – Underground Conductors/Devices	$ 228,900
#1850 – Line Transformers	$ 70,000
#1855 – Services	$ 50,000
#1995 – Contributions & Grants	-$232,768
Total Project Cost	**$ 116,132**

Budget Comparison:

At the time the budget was fixed for this project, it was expected Midland PUC would pay developers $400,000 for projects in 2009. Developments did not materialize as expected, resulting in actual spending of $116,132 and under budget variance of $283,868.

Start Date: 2009

In-Service Date: 2009

<u>2009 Project 8: Contribution and Grants</u>

Need: Midland PUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. Midland PUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense account #5705 in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001. Article 410 of the APH provides for the accounting treatment of capital contributions. The appropriate asset account is debited and account #1995 is credited with the contribution. Consequently, no return is earned in the rate base for these contributions.

Scope: Projects will be designated by customers. Once Midland PUC has completed the required work, costs will be allocated to the appropriate general ledger asset account and customer deposits will be allocated to contributed capital account #1995.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 107,269
#1835 – Overhead Conductors & Devices	$ 78,538
#1845 – Underground Conductors/Devices	$ 42,966
#1850 – Line Transformers	$ 49,573
#1855 – Services	$ 4,663
#1995 – Contributions and Grants	-$283,010
Total Project Cost	**$0.00**

Start Date: 2009

In-Service Date: 2009

<u>GENERAL PLANT PROJECT:</u>

<u>2009 Project 9: Truck Purchases</u>

Purchase of Bucket Truck; Purchase of Metering Van

Need: Vehicle Replacements: It is Midland PUC's policy to replace aging vehicles in an even fashion avoiding where possible sudden increases in capital acquisitions. Midland PUC's vehicle replacement process considers the vehicle operational condition (# of repairs and cost during the previous years), vehicle safety, mileage & age, department needs and replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

The vehicle replacement program is based on annual condition surveys and life cycle planning.

New vehicles and equipment support productivity through innovation, improve crew response time, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Truck #4 Replacement: – 1990 Ford Double Bucket Truck. This truck is 18 years old. Many repairs have been done on this truck over a number of years. There have been technical problems and rusting issues. In 2008, this vehicle underwent substantial repairs to the steel ballast framing which has rusted through. Midland PUC has been advised that additional repairs will be required over the next year, estimated at $10,000 to replace bearings. The double bucket truck has a working height of 54'. As a result of Regulation 22/04, greater clearances for conductors and hardware are required therefore, higher poles are required. The new truck would have a working platform of 60' allowing the work to be performed safely.

Truck #6 (1997 GMC Safari Van). This vehicle is 12 years old and is used by our operations department on a daily basis. This vehicle is showing the wear from daily use and has major rust problems along the lower sections of the front and rear quarter panels and doors making for costly body repairs. Midland PUC's plan is to replace this vehicle in 2009 before it becomes too costly to repair and unsafe to operate.

Scope: Purchase Bucket Truck and Van for Operations Department

Capital Costs:

Acct # & Description	**Amount**
#1930 – Transportation Equipment	$377,620
Total Project Cost	**$377,620**

Budget Comparison:

The purchase of the bucket truck was approximately $9,000 less than budgeted due to changes to the options available at the time of purchase.

Start Date: 2009

In-Service Date: 2009

<u>2009 Project #10 – Miscellaneous Projects (Each Under Materiality)</u>

Need: Provision is made for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Also included in this category are small tool purchases, computer hardware and software purchases, meter and transformer purchases.

Scope: Multiple small jobs completed throughout the year, equipment purchases, all under $50,000 materiality.

Costs: Costs are identified as per individual project and USofA # in Table 2.3.3 below:

Table 2.3.3 Project 10: Miscellaneous Project Costs

PROJECT #10		
Bourgeois Lane Kiosk	$1,765	#1845
Fault current indicators	$5,540	#1835
Kabar Replacements	$11,232	#1830/#1845
Taylor's field	$6,600	#1830
Engineering Services	$11,739	#1830
Poles, Cribs - property	$16,440	#1805
Tools	$17,153	#1940
Metering	$831	#1860
Overhead Transformers	$45,071	#1830
Borsa Lane	$10,818	#1830/35/45
Scott St. Rebuild	$1,722	#1830
Air Break Switch	$444	#1830
Misc Capital	$5,597	#1830/#1835
New Connections	$9,655	#1855/#1860
Dorion Substation	$21,504	#1820
Computer Hardware	$29,561	#1920
Computer Software	$23,218	#1925
Building & Misc Equip	$27,920	#1908/15/20
TOTAL	$246,809	

Budget Comparison:

Miscellaneous capital projects were $16,791 less than budget mainly due to the engineering fees included in the budget of $63,000 and an increase in unaccounted for small capital projects. Engineering fees included in actual spending totaled $33,243 (Dorion substation $21,504; Engineering Services project $11,739 for future pole line upgrades/rebuilds).

2009 COS Project – Bourgeois Lane Kiosk:

This project was not completed as planned in 2009. In discussions with the contractor it was determined that this project would require the re-wiring to various businesses in the downtown core. Further investigation revealed the current traceability of the wiring would need to be replaced to current standards. Consequently, additional planning and outage management required this project be transferred to 2010 and 2011.

Summary:

Although Midland PUC's capital spending in 2009 was $791,654 under budget in comparison to the OEB 2009 Approved Expenditures the cost drivers for this variance are the following:

Project	Amount
Fourth Street Substation (transferred to 2010)	$190,273
Brandon Substation	$230,007
Economic Evaluations	$283,868
Bourgeois Lane (transferred to 2010/2011)	$159,200

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Table 2.3.4 - 2010 Capital Projects

USoA #	Description	CCA Class	Project 1: Fourth St Substation	Project 2: Dorion St Substation	Project 3: Bourgeois Lane Kiosk	Project 4: Hugel Ave Pole Line	Project 5: Mapping & Asset Management	Project 6: Transformers	Project 7: Tornado Rebuild	Project 8: Economic Evaluations	Project 9: Misc Capital Projects Under $50000	Total
1805	Land	N/A										$ -
1806	Land Rights	CEC										$ -
1808	Land and Buildings	47										$ -
1810	Leasehold Improvements	13										$ -
1815	Transformer Station Equipment - Normally > 50 kV	47										$ -
1820	Distribution Station Equipment - Normally < 50 kV	47	$ 1,223,423	$ 1,175,233					$ 607		$ 9,028	$ 2,408,291
1830	Poles, Towers, Fixtures	47	$ 8,365	$ 259	$ 1,123	$ 59,400	$ 2,309		$ 32,516		$ 71,896	$ 175,868
1835	Overhead Conductors & Devices	47	$ 7,892	$ 2,872	$ 2,445	$ 52,735			$ 64,687		$ 69,211	$ 199,841
1840	Underground conduit	47			$ 2,092							$ 2,092
1845	Underground Conductor & Devices	47	$ 8,795		$ 57,659	$ 5,844			-$ 2,416	$ 126,381	$ 6,378	$ 202,641
1850	Line Transformers	47			$ 15,956			$ 54,059	$ 31,618	$ 71,465	$ 52,010	$ 225,109
1855	Services	47	$ 3,938			$ 2,024			$ 591	$ 2,849	$ 5,604	$ 15,005
1860	Meters	47							$ 56		$ 21,298	$ 21,354
1908	Building & Fixtures	47									$ 23,598	$ 23,598
1915	Office Furniture & Equipment	8									$ 7,799	$ 7,799
1920	Computer Equipment - Hardware	10									$ 28,567	$ 28,567
1925	Computer Software	12					$ 10,243				$ 29,757	$ 40,000
1930	Vehicle	10										$ -
1935	Stores Equipment	8										$ -
1940	Tools, Shop & Garage Equipment	8									$ 6,263	$ 6,263
1955	Communications Equipment	8									$ 1,857	$ 1,857
1980	System Supervisory Equipment	47					$ 95,117					$ 95,117
												$ -
												$ -
												$ -
1995	Contributions and Grants - Credit									-$ 165,423	-$ 68,664	-$ 234,087
	Total Actual Capital Expenditures		**$ 1,252,413**	**$ 1,178,364**	**$ 79,275**	**$ 120,003**	**$ 107,668**	**$ 54,059**	**$ 127,659**	**$ 35,272**	**$ 264,601**	**$ 3,219,313**
	2010 Midland PUC Board Budget		**$ 1,257,627**	**$ 1,211,400**	**$ 117,700**	**$ 135,200**	**$ 100,000**	**$ 12,400**	**$ -**	**$ 290,000**	**$ 284,500**	**$ 3,408,827**
	Variance		**-$ 5,214**	**-$ 33,036**	**-$ 38,425**	**-$ 15,197**	**$ 7,668**	**$ 41,659**	**$ 127,659**	**-$ 254,728**	**-$ 19,899**	**-$ 189,513**

<u>DISTRIBUTION PLANT PROJECTS</u>

<u>2010 Project 1: Fourth Street substation</u>

Need: This project is described under 2009 Project 1. The substation was put into service in 2010 and the bulk of costs were shown as WIP in 2009.

Capital Costs: Midland PUC incurred additional costs in 2010 in the amount of $179,886 upon energization. Total project costs are reflected below:

Acct # & Description	Amount
#1820 – Distribution Stn Equipment	$1,055,336
#1830 – Poles, Towers & Fixtures	$ 8,396
#1835 – Overhead Conductors & Devices	$ 8,795
Total Project Cost to 2009	**$1,072,527**
#1820 – Distribution Stn Equipment	$ 168,087
#1830 – Poles, Towers & Fixtures	-$ 31
#1835 – Overhead Conductors & Devices	$ 7,892
#1855 - Services	$ 3,938
Total Project Cost	**$1,252,413**

Budget Comparison:

This project was $5,214 under the projected cost of $1,257,627.

Start Date: 2009

In-Service Date: 2010

2010 Project 2: Dorion St Substation

Need: To upgrade our existing substation which is over 50 years old in accordance with the substation study completed by Rondar Engineering in 2006. The current substation is 50 years old and is in need of replacement. This will provide customers with reliable service; provide additional abilities for load transfers and the ability to upgrade to accommodate additional growth if needed. The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable substation. Additionally, replacement parts are becoming very hard to find due to the age.

Scope: To remove the existing infrastructure and install a new ground grid, 7.5M transformer with the ability to upgrade to 10M in the future and switch gear. In addition, installation of compound fencing, a new building, scada, dip pole, engineering and commissioning are included in the cost of the project.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equipment	$1,175,233
#1830 – Poles, Towers & Fixtures	$ 259
#1835 – Overhead Conductors & Devices	$ 2,872
Total Project Cost to 2009	$1,178,364

Budget Comparison:

This project cost was $33,036 less than what was budgeted mainly due to a reduction in labour hours and materials as new poles, soil testing and disposal costs were not required.

Start Date: 2010

In-Service Date: 2010

DISTRIBUTION PLANT PROJECTS

2010 Project 3: Bourgeois Lane Pad Mount – Reliability/Renewal

Need: The current configurations are very old and have been installed as new services have come onboard. The wiring is in need of replacement as it is starting to deteriorate. In the event of a primary or secondary cable failure, repairs to the existing commercial customers will be lengthy. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project except for the underground boring. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: Current wiring of the businesses is out of date, nomenclature does not correspond with the purpose for which it is intended. The wiring is disintegrating. This project will entail the installation of a new padmount transformer with wiring configurations installed to correspond to the services in place. Additional spare ducts will be installed for future primary loop feed.

The Bourgeois Lane project was completed in three sections:
#1 - remove pole mounted transformer, install a pad mount transformer on Bourgeois Lane south of Dominion Avenue in the downtown core from Royal Bank to Bank of Montreal –King St – across to Bourgeois and French’s Dry Cleaners. This configuration is a very old and has layers of installations as new businesses were connected over the years. Contractor costs are incurred to complete underground boring to bring the single and three phase services to the vault.

#2 - ducting to bring in wires. Investigation and inspection to ensure all infrastructure is running/cycling in the correct direction.

#3 – identification and inspection of existing configuration; overtime work will be required as this must be done out of business hours due to downtown core location of services.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$ 1,123
#1835 – Overhead Conductors & Devices	$ 2,445
#1840 – Underground Conduit	$ 2,092
#1845 – Underground Conductors/Devices	$ 57,659
#1850 – Line Transformers	$ 15,956
Total Project Cost	**$ 79,275**

Budget Comparison:

This project was partially completed in 2010. The relocation of existing services to the new transformers was completed in 2011 at a cost of $37,990. This 2011 expense and the 2010 expense of $79,272 total $117,262 which is in line with the budgeted costs.

Start Date: 2010

In-Service Date: 2010 (all work done in 2010 was in service in 2010)

<u>2010 Project 4: Hugel Avenue Pole Line – Renewal</u>

Need: The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects, and damage from snow plowing operations and other vehicle mishaps have contributed to their deterioration. This pole line project is required to enable Midland PUC to serve customers without putting safety and reliability at risk. In addition, if this project is planned costs can be controlled. If this project was required as the result of an emergency, costs would increase due to the nature of the emergency.

In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Existing conductors will be assessed and transferred/replaced from old poles to new poles. Transformers and existing services will be transferred from the existing pole line to the new pole line. Existing transformer loading will be calculated and if required a rebalance of the electrical load will be undertaken within the scope of this project.

Scope: Replacement of 27 poles from County Road 93 to Eighth St.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 59,400
#1835 – Overhead Conductors & Devices	$ 52,735
#1845 – Underground Conductor/Devices	$ 5,844
#1855 – Services	$ 2,024
Total Project Cost	**$120,003**

Budget Comparison:

This project resulted in $15,197 under budget variance mainly due to the use of a hydrovac machine for the excavation of the pole placements for less days than originally anticipated.

Start Date: 2010

In-Service Date: 2010

<u>2010 Project 5: Mapping (GIS), Asset Management Study – Renewal, Regulatory, Reliability</u>

Need: Asset Management has been raised as an area of concern with LDCs and the OEB. As with the substation replacement program, Midland PUC will require a plan for the replacement or upgrade of aging infrastructure. This study will provide:

1. A condition assessment of our existing infrastructure; and,
2. At the same time ensure our nomenclature is up-to-date; and
3. At the same time, analyze our infrastructure for the appropriate information required as a result of the new IFRS accounting policies; and.
4. At the same time provide Midland PUC with capabilities with GIS applications

Midland PUC has incorporated these four, although separate requirements, into one study thereby achieving economies of scale.

Scope: To commission a study of the Distribution System and set-up of mapping/GIS applications. This project has provided Midland PUC with a plan (similar to the substation study done in 2006) going forward for the upgrading/replacement of pole lines, transformers. In addition, this study has provided setup and installation of a GIS system, including the relevant mapping and nomenclature. This plan will serve as a roadmap for Midland PUC's evolution into Smart Grid technologies and compliance with IFRS accounting policies.

This project will be phased in over two years. All information and set-up of GIS application is put into service during the year costs were incurred.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 2,309
#1925 – Computer Software	$ 10,243
#1980 – System Supervisory Equipment	$ 95,117
Total Project Cost	**$107,668**

Budget Comparison:

This project was relatively on budget with extra costs attributed to the purchase of pole tags.

Start Date: 2010

In-Service Date: 2010

2010 Project 6: Transformers – Renewal/Customer Demand

Need: In compliance with OEB accounting guidelines, transformers are capitalized at the time they are purchased rather than when installed. This expenditure represents the purchased cost of transformers for installation or inventory.

Scope: Transformers are purchased throughout the year in anticipation of future expected use to service new subdivisions and renewal projects including PCB transformer replacement and prudent backup requirements.

Capital Costs:

Capital costs of $54,059 were incurred under account #1850 Line Transformers for the year 2010.

Budget Comparison:

Additional transformers were required throughout the year due to the tornado and to replenish stock.

Start Date: 2010

In-Service Date: 2010

2010 Project 7: Tornado Rebuild - Renewal

Need: On June 23, 2010 a devastating F2 tornado with peak speeds of 180 to 240 km/h struck Midland. Although no lives were lost, many Midland residents lost their homes or belongings or could only stand by and watch as what remained of their homes was deemed unsafe for occupancy.

The tornado first struck the Highway 93 corridor between Yonge Street and Highway 12. It then travelled over Little Lake and through Smith's Camp Trailer Park. Some trailers directly in the path were destroyed, others severely damaged. Businesses along King Street and Highway 12 also suffered extensive damage. Power lines were destroyed along with poles, transformers , cross arms, insulators, etc.

Scope: With the goal of restoring power as quickly as possible, Midland PUC crews immediately canvassed the affected areas to see the extent of help needed. Midland PUC made arrangements with two CHEC LDCs, Wasaga Beach and Collingwood, to help our crews restore power to the town as fast as we could. While Midland PUC was replacing its infrastructure, Hydro One was repairing its distribution lines along Highway 93 and Newmarket-Tay Power was restoring power to their affected customers. Once these two LDCs finished their repairs they readily lent a hand to Midland PUC.

These crews worked tirelessly over the following days to restore power and complete the cleanup of the affected areas. Over 3000 Midland customers were without power for most of the night. By the following morning (June 24th) Midland PUC had restored power to half of those customers. Later that morning most customers had power, except of course those that sustained damage. By 5 p.m., less than 24 hours after the tornado hit, all customers who were not directly affected by the tornado, had power restored.

By the end of the weekend, Midland PUC finished the upgrades to its distribution system and restored power to all affected residents and businesses that could safely be energized.

Midland PUC distribution system upgrades:

King Street	new pole line rebuild
Brandon Field	new pole line rebuild
Albert Street	new pole line rebuild
Taylor Field	new pole line rebuild

Capital Costs:

Over $350,000 in infrastructure damage resulted from the tornado. In 2010, Midland PUC divided the costs into two categories – Group 1 costs included Midland PUC labour (regular hours) and materials totaling $127,659. The Group 2 costs included incremental labour (overtime), neighbouring LDC charges, subcontractor costs and material costs totaling $228,215. Group 1 costs were recorded as a capital project for the year 2010 as non-incremental capital renewal costs. Group 2 costs were recorded under Regulatory Assets in 2010 for application to the OEB under a Z Factor IRM application during the 2011 IRM process, subject to Midland PUC Board of Director Approval.

Group 1 Costs:

Acct # & Description	**Amount**
#1820 – Distribution Stn Equipment	$ 607
#1830 – Poles, Towers & Fixtures	$ 32,516
#1835 – Overhead Conductors & Devices	$ 64,687
#1845 – Underground Conductor & Devices	-$ 2,416
#1850 – Line Transformers	$ 31,618
#1855 – Services	$ 591
#1860 - Meters	$ 56
Total Project Cost	$127,659

Start Date: 2010

In-Service Date: 2010

2010 Project 8: Economic Evaluations – Developer Contributions – Customer Demand

Need: The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization Midland PUC records the assets and the offsetting contributed capital.

Scope: In 2010, development contributions totaled $165,423 for the Timberridge development.

Capital Costs:

Acct # & Description	Amount
#1845 – Underground Conductors/Devices	$ 126,381
#1850 – Line Transformers	$ 71,465
#1855 – Services	$ 2,849
#1995 – Contributions & Grants	-$165,423
Total Project Cost	**$ 35,272**

Budget Comparison:

In 2010, Midland PUC budgeted $290,000 for the Tiffin Garden Estates and Mundys Harbour Developments. During the year, these developments did not materialize, however, payment on the Timberridge Development was made.

Start Date: 2010

In-Service Date: 2010

2010 Project #9: Contribution and Grants – (Small Capital Projects < $50,000)

Need: Midland PUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. Midland PUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense account #5705 in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001. Article 410 of the APH provides for the accounting treatment of capital contributions. The appropriate asset account is debited and account #1995 is credited with the contribution. Consequently, no return is earned in the rate base for these contributions.

Scope: Projects will be designated by customers. Once Midland PUC has completed the required work, costs will be allocated to the appropriate general ledger asset account and customer deposits will be allocated to contributed capital account #1995.

Capital Costs:

In 2010, numerous small projects were included as contributed capital, the costs of which are included under the small projects under $50,000 category below.

Start Date: 2010

In-Service Date: 2010

2010 Project #9 – Miscellaneous Projects (Each Under Materiality)

Need: Provision is made for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Also included in this category are small tool and equipment purchases, computer hardware and software purchases, meter and transformer purchases.

Scope: Multiple small jobs completed throughout the year, equipment purchases, all under $50,000 materiality.

Costs: Costs are identified as per individual project and USofA # in the following table:

Table 2.3.5 Project 9: Miscellaneous Project Costs

PROJECT #9		Amount	USofA#
Air Break Switch	$	22,845	#1830/35/50
Bay Street Pole Rebuild	$	15,705	#1830/#1840
Vinden St. Pole & Conducto	$	10,956	#1830/#1840
Pad Mount Transformers	$	2,057	#1850
Pole Replacements	$	31,361	#1830/#1840
Kabar Replacements	$	3,707	#1845
New Service Connections	$	6,131	#1855/#1860
Misc Capital Work	$	17,974	#1820/30/35/45/50
Yonge St Pole Line	$	8,727	#1830
Sunnyside Pole Line	$	17,966	#1830/35/45/50
Substation Security Sys	$	9,293	#1820/#1908
Computer hardware/software	$	29,226	#1915/1920/1925
Office Furniture & Equip	$	5,091	#1915
Harris CIS upgrade	$	21,150	#1925
Telephone Sys Upgrade	$	9,654	#1920
Building windowfilm	$	2,810	#1908
Tools	$	6,263	#1940
Meters	$	20,688	#1955
Generator	$	20,140	#1908
Portable Radios	$	2,858	#1915/#1955
TOTAL	$	264,601	

Budget Comparison:

Miscellaneous capital projects were $19,899 less than budget mainly due to a decrease in unaccounted for small capital projects. As well, the number of transformer purchases was reduced due to the replenishment under the tornado project.

Table 2.3.6 - 2011 Capital Projects

USoA #	Description	CCA Class	Project 1: Gloucester Pole Line	Project 2: Bay St Pole Line	Project 3: Albert St Pole Line	Project 4: Pole Replacements Misc	Project 5: Mapping & Asset Management	Project 6: Tornado Rebuild	Project 7: Economic Evalulations	Project 8: Contributions & Grants	Project 9: Misc Capital Projects Under $50000	Total
1805	Land	N/A										$ -
1806	Land Rights	CEC										$ -
1808	Land and Buildings	47										$ -
1810	Leasehold Improvements	13										$ -
1815	Transformer Station Equipment - Normally > 50 kV	47										$ -
1820	Distribution Station Equipment - Normally < 50 kV	47									$ 18,427	$ 18,427
1830	Poles, Towers, Fixtures	47	$ 56,552	$ 51,187	$ 40,890	$ 70,326		$ 77,745		$ 32,084	$ 39,955	$ 368,739
1835	Overhead Conductors & Devices	47	$ -	$ 38,152	$ 24,852	$ -		$ 76,177		$ 8,917	$ 25	$ 148,123
1840	Underground conduit	47									$ 1,514	$ 1,514
1845	Underground Conductor & Devices	47	$ -			$ -				$ 54,258	$ 11,423	$ 65,680
1850	Line Transformers	47		$ -		$ -				$ 27,858	$ 49,489	$ 77,346
1855	Services	47	$ -	$ 6,220	$ -	$ -		$ 74,292			$ 40,943	$ 121,455
1860	Meters	47								$ 1,269	$ 37,544	$ 38,813
1908	Building & Fixtures	47									$ 41,411	$ 41,411
1915	Office Furniture & Equipment	8									$ 16,519	$ 16,519
1920	Computer Equipment - Hardware	10									$ 6,075	$ 6,075
1925	Computer Software	12									$ 17,303	$ 17,303
1930	Vehicle	10									$ 2,425	$ 2,425
1935	Stores Equipment	8									$ 6,697	$ 6,697
1940	Tools, Shop & Garage Equipment	8									$ -	$ -
1955	Communications Equipment	8									$ -	$ -
1980	System Supervisory Equipment	47					$ 110,198				$ -	$ 110,198
											$ -	$ -
											$ -	$ -
											$ -	$ -
1995	Contributions and Grants - Credit								-$ 141,484	-$ 124,385		-$ 265,869
	Total Actual Capital Expenditures		**$ 56,552**	**$ 95,559**	**$ 65,742**	**$ 70,326**	**$ 110,198**	**$ 228,215**	**-$ 141,484**	**$ -**	**$ 289,747**	**$ 774,855**
	2011 Midland PUC Board Budget		**$ 52,400**	**$ 68,900**	**$ 47,500**	**$ 80,300**	**$ 118,100**		**$ 157,000**	**$ -**	**$ 346,100**	**$ 870,300**
	Variance		**$ 4,152**	**$ 26,659**	**$ 18,242**	**-$ 9,974**	**-$ 7,902**	**$ 228,215**	**-$ 298,484**	**$ -**	**-$ 56,353**	**-$ 95,445**

<u>2011 Project 1: Gloucester Pole Line: - Reliability/Renewal</u>

Need: Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring was replaced. Wiring was restrung. Existing transformer loading was calculated and a rebalancing of the electrical load was undertaken within the scope of this project.

The current pole line is in poor condition. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To replace 9 poles on Gloucester Street from William St. to Manly St. in the Town of Midland.

Capital Costs: Project costs of $56,552 were recorded in account #1830 Poles, Towers & Fixtures

Budget Comparison:

This project cost was $4,152 over what was originally budgeted, mainly due to additional overtime labour hour requirements. One additional day was required for the hydrovac machine to excavate the pole placements.

Start Date: 2011

In-Service Date: 2011

<u>2011 Project 2: Bay Street Reconductoring and Pole Line: - Reliablity/Renewal</u>

Need: The current conductor is too small to enable effective switching and loading in this area. This upgrade required wiring to be restrung. Existing transformer loading was calculated and if required a rebalance of the electrical load was undertaken within the scope of this project.

Pole tops are rotting from years of adverse weather effects, including damage from snow ploughing operations and other vehicle mishaps. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring was placed.

The current pole line is too small and needs to be upgraded to provide adequate switching and loading capabilities. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To reconductor a section of the Bay Street pole line from King Street to Russell Street in Town of Midland, to include the replacement of 8 poles.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 51,187
#1835 – Overhead Conductors & Devices	$ 38,152
#1855 – Services	$ 6,220
Total Project Cost	$ 95,559

Budget Comparison:

This project cost was $26,659 over what was originally budgeted. At the time of construction a sewer main, not identified in the original plan was encountered. This unanticipated event, resulted in relocation of poles and additional survey costs. In addition, labour hours were incurred and overtime was required due to the nature of the work being performed in the downtown core. Due to the relocation of the pole line, the height of the poles was increased in accordance with ESA standards.

Start Date: 2011

In-Service Date: 2011

2011 Project 3: Albert Street Pole Line: - Renewal, Reliability

Need: Pole tops are rotting from years of adverse weather effects. Poles have become unstable as they are presently located in a field. In conjunction with pole relocation, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Wiring will be restrung. Existing transformer loading will be calculated and if required a rebalance of the electrical load will be undertaken within the scope of this project.

The current pole line is in poor condition. The location of this pole line is in the field near Kindred Industries. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum. Access to the existing pole line in inclement weather is hazardous as well.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To relocate 9 poles from the field lying in Franke Kindred property to the pole line along William and Albert Streets in Town of Midland.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 40,890
#1835 – Overhead Conductors & Devices	$ 24,852
Total Project Cost	$ 65,742

Budget Comparison:

This project was over budget by $18,242, mainly due to the installation of four additional poles not included in the original forecast. Additional switches were identified as being required to be replaced at the time of installation. Additional work ($16,100) which was budgeted in the 44kV Feeder Improvement Project under Miscellaneous Projects was included in this project due to the close proximity of the two projects. The 44kV Feeder Improvement project was originally budgeted at $24,800. Actual costs were $10,262, a variance of $16,100. Consequently, the Albert Street Project #3 came in relatively on budget.

Start Date: 2011

In-Service Date: 2011

2011 Project 4: Miscellaneous Pole Replacements: - Renewal

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority.

Scope: 12 poles were identified and replaced. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring were replaced as required. Existing transformer loading was calculated and rebalanced as required.

Capital Costs: Project costs of $70,326 were recorded in account #1830 Poles, Towers & Fixtures

Budget Comparison:

Actual costs were $9,974 less than what was budgeted, mainly due to less labour and inventory requirements on this project as less work was required on the project.

Start Date: 2011

In-Service Date: 2011

<u>2011 Project 5: Mapping (GIS), Asset Management Study – Renewal, Regulatory, Reliability</u>

Need: Particulars of this project are described under "2010 Project 5: Mapping (GIS), Asset Management Study – Renewal, Regulatory, Reliability". The 2011 Project represents the second phase of the two year project cost.

Capital Costs: Project costs of $110,198 were recorded in account #1980 System Supervisory Equipment

Budget Comparison:

The total budget for this project for both 2010 and 2011 totalled $218,100 ($118,100 for 2011 and $100,000 for 2010). Actual costs totalled $217,866 ($110,198 for 2011 and $107,668 for 2010). Overall, this project has been on budget.

Start Date: 2011

In-Service Date: 2011

2011 Project 6: Tornado Rebuild: - Renewal

Need: On June 23, 2010 a devastating F2 tornado with peak speeds of 180 to 240 km/h struck Midland. This project is more particularly described under "2010 Project 7: Tornado Rebuild – Renewal".

Capital Costs: As mentioned above, over $350,000 in infrastructure damage resulted from the tornado. In 2010, Midland divided the costs into two categories – Group 1 costs included Midland PUC labour (regular hours) and materials totaling $127,659. The Group 2 costs included incremental labour costs (overtime), materials, neighbouring LDC charges, subcontractor costs totaling $228,215. Group 1 costs were recorded as a capital project for the year 2010 as non-incremental capital renewal costs. Group 2 costs were recorded under Regulatory Assets in 2010 for application to the OEB under a Z Factor IRM application during the 2011 IRM process, subject to Midland PUC Board of Director approval. In 2011, Midland PUC Board approved the allocation of the Group 2 costs to capital from Regulatory Assets as a capital project in 2011, as evidenced by the Audited Financial Statements as at December 31, 2011.

Group 2 Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 77,745
#1835 – Overhead Conductors & Devices	$ 76,177
#1855 – Services	$ 74,292
Total Project Cost	$228,215

Start Date: 2010

In-Service Date: 2010 (transferred to Capital in 2011)

<u>2011 Project 7: Economic Evaluations – Developer Contributions – Customer Demand</u>

Need: The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, Midland PUC records the assets and the offsetting contributed capital.

Scope: The 2009 economic evaluation for Riverwalk Green Phase 1 development was updated in 2011. In 2009, development contributions totalled $232,768 on the Riverwalk Green Phase 1 development. In 2011, contributions and grants were increased resulting in a further credit to contributed capital of $106,212.

The 2010 economic evaluation for Timberridge was updated in 2011. In 2010, development contributions totaled $165,423 on the Timberridge development. In 2011, contributions and grants were increased resulting in a further credit to contributed capital of $35,272. These two projects totaled $141,484 (Riverwalk Green Phase 1 - $106,212; Timberridge $35,272).

Capital Costs:

Acct # & Description	Amount
#1995 – Contributions & Grants	-$ 141,484
Total Project Cost	**-$ 141,484**

Budget Comparison:

In 2011, Midland PUC included $157,000 in its budget for payment to developments Riverwalk Greens Phase 2, Tiffin Garden Estates and Mundys Harbour. These projects did not materialize as expected.

<u>2011 Project #8: Contribution and Grants</u>

Need: Midland PUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. Midland PUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense account #5705 in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001. Article 410 of the APH provides for the accounting treatment of capital contributions. The appropriate asset account is debited and account #1995 is credited with the contribution. Consequently, no return is earned in the ratebase for these contributions.

Scope: Projects will be designated by customers. Once Midland PUC has completed the required work, costs will be allocated to the appropriate general ledger asset account and customer deposits will be allocated to contributed capital account #1995.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$ 32,084
#1835 – Overhead Conductors & Devices	$ 8,917
#1845 – Underground Conductors/Devices	$ 54,258
#1850 – Line Transformers	$ 27,858
#1860 – Meters	$ 1,269
#1995 – Contributions & Grants - Customers	-$ 124,385
Total Project Cost	**$ 0**

Start Date: 2011

In-Service Date: 2011

2011 Project #8– Miscellaneous Projects (Each Under Materiality)

Need: Provision is made for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Also included in this category are small tool and equipment purchases, computer hardware and software purchases, meter and transformer purchases.

Scope: Multiple small jobs completed throughout the year, equipment purchases, all under $50,000 materiality.

Costs: Costs are identified as per individual project and USofA# in Table 2.3.7.

Budget Comparison:

Miscellaneous projects were budgeted at $346,100 in 2011 vs actual costs of $289,747 which resulted in an under budget variance of $56,353. The 44kV Feeder Improvement project was originally budgeted at $24,800. Actual costs were $10,262, a variance of $16,100. Additional work which was included in this project was incorporated into the Albert Street Project #3 which was over budget by $18,242. Consequently, the Albert Street Project #3 came in relatively on budget. The Miscellaneous Projects variance would therefore be reduced by $16,100 to $40,253.

Two small building projects at the substations (replacement of windows and doors) totaling $23,000 were transferred to 2012 as the materials were on backorder. Bourgeois Lane Kiosk project labour and material actual costs were $10,400 less than budgeted.

Table 2.3.7 Project 8: Miscellaneous Project Costs

PROJECT #8	AMOUNT		ACCOUNT #
Montreal Substation	$	8,500	#1820
Queen Substation	$	8,500	#1820
Bourgeois Lane	$	37,990	#1840/45/55
44kV Feeder Improvements	$	10,262	#1830
Pad Mount Transformers	$	5,993	#1850
Pole Mount Transformers	$	4,345	#1850
Kabar Replacements	$	5,685	#1845
New Connections	$	15,260	#1830/55/60
Misc Capital Work	$	28,193	#1820/30/35
Tools	$	6,697	#1940
Meters	$	35,439	#1860
Trasnformers	$	39,150	#1850
Vehicle	$	2,425	#1930
Computer Hardware/Software	$	23,377	#1920/#1925
Building	$	41,411	#1908
Furniture & Equipment	$	16,519	#1915
TOTAL	$	289,747	

Table 2.3.8 - 2012 Capital Projects

USoA #	Description	CCA Class	Project 1: Montreal St Substation	Project 2: William St. North Pole Line	Project 3: Pratt's Field Pole Line	Project 4: Selected Pole Replacements	Project 5: Economic Evaluations	Project 6: Transformers	Project 7: Smart Meter Infrastructure Implementation	Project 8: Contributions & Grants	Project 9: Vehicles	Project 10: Misc Capital Projects Under $50000	Total
1805	Land	N/A											$ -
1806	Land Rights	CEC											$ -
1808	Land and Buildings	47											$ -
1810	Leasehold Improvements	13											$ -
1815	Transformer Station Equipment - Normally > 50 kV	47											$ -
1820	Distribution Station Equipment - Normally < 50 kV	47	$ 563,200										$ 563,200
1830	Poles, Towers, Fixtures	47		$ 130,000	$ 59,400	$ 84,100				$ 48,000		$ 2,100	$ 323,600
1835	Overhead Conductors & Devices	47		$ 20,760	$ 12,000					$ 39,500		$ 18,900	$ 91,160
1840	Underground conduit	47											$ -
1845	Underground Conductor & Devices	47					$ 255,000			$ 121,300		$ 16,200	$ 392,500
1850	Line Transformers	47					$ 145,000	$ 87,200		$ 71,400			$ 303,600
1855	Services	47					$ 7,000			$ 13,900		$ 13,000	$ 33,900
1860	Meters	47							$ 1,186,439			$ 13,000	$ 1,199,439
1908	Building & Fixtures	47										$ 45,000	$ 45,000
1915	Office Furniture & Equipment	8											$ -
1920	Computer Equipment - Hardware	10							$ 18,764			$ 29,500	$ 48,264
1925	Computer Software	12							$ 86,048			$ 10,200	$ 96,248
1930	Vehicle	10									$ 536,200		$ 536,200
1935	Stores Equipment	8											$ -
1940	Tools, Shop & Garage Equipment	8										$ 16,900	$ 16,900
1955	Communications Equipment	8											$ -
1980	System Supervisory Equipment	47											$ -
													$ -
													$ -
													$ -
1995	Contributions and Grants - Credit						-$ 300,000			-$ 294,100			-$ 594,100
	Total Capital Expenditures		**$ 563,200**	**$ 150,760**	**$ 71,400**	**$ 84,100**	**$ 107,000**	**$ 87,200**	**$ 1,291,251**	**$ -**	**$ 536,200**	**$ 164,800**	**$ 3,055,911**

2012 Project 1: Montreal Street Substation

Need: This substation is the 5th in the series of 6 substations to be upgraded/renewed in accordance with the substation study completed by Rondar in 2006. This study was updated in a Load Study in 2011. A copy of the Load Study is attached as Appendix A. This project will upgrade the existing induction disc relays with a microprocessor based system to provide more information pertaining to the daily operation of the power system. In addition, installation of ground conductor connecting to the substation ground grid; installation of a second bonding connection between the ground grid and ground bus within the switchgear; upgrading the bonding connection between the three lightning arresters to include a continuous loop to a second connection to the ground grid; replacement of 3 lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV; relocation of existing cables into the back of the switchgear; installation of power fuses; installation of a residual connected ground fault relay.

The current substation is in need of upgrading. This will provide customers with reliable service, provide additional abilities for load transfers and the ability to upgrade to accommodate additional growth if needed.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable substation. Additionally, replacement parts are becoming very hard to find due to the age.

Scope: To upgrade existing switchgear at Montreal Substation.

Midland PUC requested four quotes. Tiltran, Wilson High Voltage and Black and MacDonald quoted on this project for this upgrade and consequently, we have been able to keep costs to a minimum. Rondar declined to quote. Commercial Switch Gear is the only certified Areva representative and our four previous stations are equipped with Areva gear. Consequently, Midland PUC chose Areva switch gear. Areva is now owned by Schneider Ltd. The quote provided by Tiltran includes Areva Switchgear and the required factory testing and programming similar to the other substations which have been upgraded in past years. Tiltran will also provide the programming to connect with our SCADA system. These costs are not included in the Wilson High Voltage and Black and MacDonald quotes and have been added to these quotes for comparative purposes.

Capital Costs: Project costs of $563,200 are budgeted in account #1820, Distribution Station Equipment.

Start Date: 2012

In-Service Date: 2012

2012 Project 2: William St. North Pole Line: - Reliablity/Renewal

Need: Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Wiring will be restrung. Existing transformer loading will be calculated and if required, a rebalance of the electrical load will be undertaken within the scope of this project. Both 5KV circuits will be re-conductored and the 44KV conductor will be transferred.

The current pole line is in poor condition. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To replace 20 poles along William Street from Yonge to Gloucester in the Town of Midland.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$130,000
#1835 – Overhead Conductors & Devices	$ 20,760
Total Project Cost	$150,760

Start Date: 2012

In-Service Date: 2012

<u>2012 Project 3: Pratt's Field Pole Line – Reliability/Renewal</u>

Need: The existing 4.16Kv, 44Kv pole line is in poor condition. Pole tops are rotting from years of adverse weather effect. Insulators and conductor are undersized. In addition to the transfer of the two existing 4.16Kv feeders, a 44Kv extension will be added between Dorion substation and Brandon Road to provide a tie line onto the Waubaushene TS M4 feeder. This project will require the construction of a temporary access road.

The current pole line is in poor condition. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old, and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To replace 10 poles on Pratt's Field between the Dorion substation and King Street, in the Town of Midland.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$59,400
#1835 – Overhead Conductors & Devices	$12,000
Total Project Cost	$71,400

Start Date: 2012

In-Service Date: 2012

<u>2012 Project 4: Selected Pole Replacements: - Renewal</u>

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority

Scope: 30 poles were identified to be replaced. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be replaced as required. Existing transformer loading will be calculated and rebalanced as required.

Capital Costs: Project costs of $84,100 were budgeted and recorded in account #1830 Poles, Towers & Fixtures

Start Date: 2012

In-Service Date: 2012

2012 Project 5: Economic Evaluations – Developer Contributions – Customer Demand

Need: The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, in 2012, Midland PUC expects to pay a transfer price of $107,000 for the assets installed by the developer.

Scope: Midland PUC has budgeted the transfer price to the developer of Riverwalk Greens Phase 2 in the amount of $57,000 and to VLA in the amount of $50,000.

Capital Costs:

Acct # & Description	**Amount**
#1845 – Underground Conductors/Devices	$ 255,000
#1850 – Line Transformers	$ 145,000
#1855 – Services	$ 7,000
#1995 – Contributions & Grants	-$ 300,000
Total Project Cost	**$ 107,000**

Start Date: 2012

In-Service Date: 2012

2012 Project 6: Transformers – Renewal/Customer Demand

Need: In compliance with OEB accounting guidelines, transformers are capitalized at the time they are purchased rather than when installed. This expenditure represents the purchased cost of transformers for installation or inventory.

Scope: Transformers are purchased throughout the year in anticipation of future expected use to service new subdivisions, renewal projects and prudent backup requirements.

Capital Costs: Capital costs of $87,200 are budgeted under account #1850 Line Transformers for the year 2012.

Start Date: 2012

In-Service Date: 2012

2012 Project 7: Smart Meter Infrastructure – Renewal/Regulatory

Need: The provincial smart meter initiative was implemented to achieve the government objective for deployment of smart electricity meters in every home by December 31, 2010. The underlying premise behind this mandate was to educate customers on their consumption habits and to implement new rate structures that encouraged load shifting and conservation of energy, thereby reducing the requirement for increased power generation capabilities. In accordance with this provincial initiative, Midland PUC became authorized to deploy smart meters under O.Reg 427/06 as amended by O.Reg 238/09 in accordance with the London Hydro RFP process.

Midland PUC complied with the Regulation and the London Hydro RFP process for the procurement of smart meters and associated equipment and for services to install and operate the smart meters and associated equipment.

Scope: Midland PUC, working with other members of the CHEC Group (Cornerstone Hydro Electric Concepts Inc.) installed meters and related infrastructure in 2009 and 2010 and by June, 2011 started billing on Time-of-Use rates to all residential and general service < 50kW customers.

In December, 2011 Midland PUC submitted its Application to the Ontario Energy Board (EB-2011-0434) for recovery of costs associated with this initiative and pursuant to the Decision and Order dated May 3, 2012, all capital and OM&A costs were approved. Capital costs, although incurred in previous years were transferred from Regulatory Assets to capital in 2012.

Capital Costs:

Acct # & Description	Amount
#1860 - Meters	$ 1,186,439
#1920 – Computer Hardware	$ 18,764
#1925 – Computer Software	$ 86,048
Total Project Cost	**$ 1,291,251**

Start Date: 2006

In-Service Date: 2012

2012 Project 8: Contribution and Grants

Need: Midland PUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. Midland PUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense account #5705 in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001. Article 410 of the APH provides for the accounting treatment of capital contributions. The appropriate asset account is debited and account #1995 is credited with the contribution. Consequently, no return is earned in the rate base for these contributions.

Scope: Projects will be designated by customers. Once Midland PUC has completed the required work, costs will be allocated to the appropriate general ledger asset account and customer deposits will be allocated to contributed capital account #1995.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 48,000
#1835 – Overhead Conductors & Devices	$ 39,500
#1845 – Underground Conductors/Devices	$ 121,300
#1850 – Line Transformers	$ 71,400
#1855 – Services	$ 13,900
#1995 – Contributions and Grants	-$294,100
Total Project Cost	**$0.00**

Start Date: 2012

In-Service Date: 2012

GENERAL PLANT PROJECT:

2012 Project 9: Truck Purchases – Bucket Truck, Digger Derrick, Dump Trailer

Need: Vehicle Replacements: It is Midland PUC's policy to replace aging vehicles in an even fashion avoiding where possible, sudden increases in capital acquisitions. Midland PUC's vehicle replacement process considers the vehicle operational condition (# of repairs and cost during the previous years), vehicle safety, mileage & age, department needs and replacement of vehicles before they become costly to repair, uneconomic and unsafe to operate.

The vehicle replacement program is based on annual condition surveys and life cycle planning.

New vehicles and equipment support productivity through innovation, improve crew response time, reduce fuel costs, lower maintenance costs, and increase environmental responsibility through fuel reduction and alternate fuel usage.

Purchase of Bucket Truck:

Truck #3 Replacement: – 1993 GMC Kodiak Single Bucket Truck. This truck is 20 years old. Many repairs have been done on this truck over a number of years. There have been technical problems and rusting issues. This truck is used in connecting secondary services, pole mount transformers and construction of high voltage power lines in the day-to-day operations at Midland PUC. Midland PUC's distribution system includes

44 kV feeders, 8.32 kV feeders and 4.16kV feeders. As a result of this large diversity, it is necessary to purchase this truck to reach 50 feet with full material handling capabilities.

Truck #3 is well beyond its useful life and the cost of extraordinary repairs is rising substantially year after year. In 2009 the costs were $1,500, in 2010 $4,000, in 2011 $14,000. We are advised parts are becoming very scarce for this vehicle. In addition, critical components are failing more frequently. The steel body has deteriorated to the point where it will need to be repaired at a cost of $12,000. This repair will not be required once replaced in 2012.

Midland PUC looked at various options – renting, purchasing new, purchasing used. There are no rental or secondhand vehicles available with the required specifications. Midland PUC also determined we would not receive a discount by purchasing two trucks (i.e. the digger derrick and single bucket from the same supplier). Therefore, it is not necessary to purchase the vehicles from the same manufacturer. There is a small trade-in value associated with this truck.

Midland PUC has explored the option of renting a vehicle only during the months of heavy capital work. This will leave Midland PUC vulnerable to lack of equipment for emergency outages and day-to-day operations. Consequently, this is not an option. Midland PUC has determined rental costs would be approximately $50,000 to $60,000 per year and by purchasing the vehicle we could recoup that cost in 3 years (i.e. $180k / 3 years = $60k). Midland PUC's 2012 budget includes the purchase of a 2012 Single Bucket Truck at a cost of $250,000, less a trade-in allowance of $8,000 for a net cost of $242,000.

<u>Purchase of a 2012 Digger Derrick Truck:</u>

The Digger Derrick truck is used for augering holes and hoisting poles into place. It is also used to hoist pole mount or pad mount transformers. Midland PUC's plan is to sell the current vehicle (2006 International Digger Derrick) and use those proceeds to reduce the overall cost of the new vehicle. Due to the nature of work on and around energized power lines and in close proximity to personnel, it is imperative the boom operates in conjunction with intentional commands. Over the past couple of years there have been severe issues with the operation of the boom with the current Digger Derrick in that at times the boom does not respond to the operator's directions. For example, if the operator is positioning the boom to go in direction "A" the boom will on its own, move itself in direction "B". Although this by itself may seem to be a minor defect, the problem cannot be resolved easily and safety concerns may put our employees at risk. This problem was identified and reported to the manufacturer. Numerous attempts to repair this problem over the past year have proven unsuccessful.

Midland PUC looked at two options:

1. Repair the existing Digger Derrick and continue operating:
   The repairs needed for this truck include the repair of the leaking turntable and the change to electric controls over hydraulics. Even with these repairs, the manufacturer will not warranty the work and will not guarantee the hydraulics will be effective. Without the guarantee and warranty this is not an option.

2. Repair the truck and sell it: Repairs will be needed to maximize the sale value of this truck. By selling the truck now, Midland PUC will be maximizing the sale price as its value will diminish

significantly as years progress. Midland PUC is advised a 2004 unit is currently selling in the $60,000 range. In addition, we are advised the Digger Derrick truck's value is high at this point due to the year and configuration.

The gross cost of $275,400 will be offset by the sale of the 2006 model of $100,000, for a net cost to Midland PUC of $175,400.

There are no rental or used vehicles available with the required specifications. Investigations revealed there were 2 used 2007 vehicles that have been sold recently at a cost of $140,000 per vehicle vs. the net cost to Midland PUC of $175,400 for a 2012 vehicle.

Purchase of an aluminum Dump Trailer:

This trailer is used by Midland PUC in day-to-day operations in transporting of materials to jobs, tree trimming and transformer transport.

Scope: To purchase a 2012 Single Bucket Truck at a cost of $250,000; to purchase a 2012 Digger Derrick Truck at a net cost of $275,400; to purchase an aluminum dump trailer at a net cost of $10,800.

Capital Costs: Project costs of $536,200 are budgeted in account #1930, Transportation Equipment.

Start Date: 2012

In-Service Date: 2012

2012 Project #10 – Miscellaneous Projects (Each Under Materiality)

Need: Provision is made for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Also included in this category are small tool purchases, computer hardware and software purchases, meter and transformer purchases.

Scope: Multiple small jobs completed throughout the year, equipment purchases, all under $50,000 materiality.

Costs: Costs are identified as per individual project and USofA # in the following table:

Table 2.3.9 Project 10: Miscellaneous Project Costs

PROJECT #10	**AMOUNT**		**ACCOUNT #**
Kabar Replacements	$	16,200	#1845
New Service Connections	$	13,000	#1855
Misc Capital Work	$	21,000	#1830/#1835
Tools	$	16,900	#1940
Meters	$	13,000	#1860
Hardware	$	29,500	#1920
Software	$	10,200	#1925
Building	$	45,000	#1908
TOTAL	$	164,800	

Table 2.3.10 - 2013 Capital Projects

USoA #	Description	CCA Class	Project 1: Queen St Substation	Project 2: William St. South Pole Line	Project 3: Fourth St Pole Line	Project 4: Selected Pole Replacements	Project 5: Economic Evaluations	Project 6: Transformers	Project 7: Contributions and Grants	Project 8: Scada	Project 9: Harris CIS Upgrade	Project 10: Misc Capital Projects Under $50000	Total
1805	Land	N/A											$ -
1806	Land Rights	CEC											$ -
1808	Land and Buildings	47											$ -
1810	Leasehold Improvements	13											$ -
1815	Transformer Station Equipment - Normally > 50 kV	47											$ -
1820	Distribution Station Equipment - Normally < 50 kV	47	$ 896,700										$ 896,700
1830	Poles, Towers, Fixtures	47		$ 133,600	$ 85,300	$ 84,100			$ 48,000			$ 2,100	$ 353,100
1835	Overhead Conductors & Devices	47		$ 29,300	$ 12,000				$ 39,500			$ 18,900	$ 99,700
1840	Underground conduit	47											$ -
1845	Underground Conductor & Devices	47					$ 250,000		$ 121,300			$ 16,200	$ 387,500
1850	Line Transformers	47			$ 20,300		$ 140,000	$ 87,200	$ 71,400				$ 318,900
1855	Services	47					$ 4,000		$ 13,900			$ 13,000	$ 30,900
1860	Meters	47										$ 10,000	$ 10,000
1908	Building & Fixtures	47										$ 25,000	$ 25,000
1915	Office Furniture & Equipment	8											$ -
1920	Computer Equipment - Hardware	10								$ 12,265		$ 9,900	$ 22,165
1925	Computer Software	12									$ 55,000		$ 55,000
1930	Vehicle	10											$ -
1935	Stores Equipment	8											$ -
1940	Tools, Shop & Garage Equipment	8										$ 10,000	$ 10,000
1955	Communications Equipment	8											$ -
1980	System Supervisory Equipment	47								$ 175,000			$ 175,000
													$ -
													$ -
													$ -
1995	Contributions and Grants - Credit						-$ 294,000		-$ 294,100				-$ 588,100
Total			**$ 896,700**	**$ 162,900**	**$ 117,600**	**$ 84,100**	**$ 100,000**	**$ 87,200**	**$ -**	**$ 187,265**	**$ 55,000**	**$ 105,100**	**$ 1,795,865**

2013 Project 1: Queen Street Substation

Need: This substation is the 6^{th} in the series of 6 substations to be upgraded/renewed in accordance with the substation study completed by Rondar in 2006. This study was updated in a Load Study in 2011. A copy of the Load Study is attached as Appendix A. The current substation is over 50 years old and is in need of upgrading. This will provide customers with reliable service, provide additional abilities for load transfers and the ability to upgrade to accommodate additional growth if needed.

This project will upgrade the existing induction disc relays with a microprocessor based system to provide more information pertaining to the daily operation of the power system. In addition, installation of new switchgear complete with vacuum air circuit breakers and a standalone relay panel; installation of ground conductor connecting to the substation ground grid; installation of a second bonding connection between the ground grid and ground bus within the switchgear; upgrading the bonding connection between the three lightning arresters to include a continuous loop to a second connection to the ground grid; replacement of 3 lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV; The current transformer will be upgraded to a 10MVA power transformer which is recommended as per the Load Study completed in 2011.

The risks of not proceeding with the project include increased threats of major failure due to an old and potentially unreliable substation. Additionally, replacement parts are becoming very hard to find due to the age.

Scope: To upgrade our existing 5MVA substation built in 1954, in accordance with the substation study completed by Rondar Engineering in 2006 and Load Study completed in 2011. Midland has received three quotes for this upgrade and therefore has been able to keep costs to a minimum. Commercial Switch Gear is the only certified Areva representative and our five previous stations are equipped with Areva gear. Consequently, Midland PUC chose Areva switch gear. The current transformer will be upgraded to a 10MVA power transformer which is recommended as per the load study completed in 2011. The existing 5 MVA transformer will be kept in stock for backup purposes as it can backup both Queen and Montreal stations if required.

Capital Costs: Project costs of $896,700 are budgeted in account #1820, Distribution Station Equipment.

Start Date: 2013

In-Service Date: 2013

<u>2013 Project 2: William St. South Pole Line: - Reliability/Renewal</u>

Need: Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Wiring will be restrung. Existing transformer loading will be calculated and if required, a rebalance of the electrical load will be undertaken within the scope of this project.

The current pole line is in poor condition. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To replace 26 poles along William Street, south of Yonge Street to Bayview Drive (Birchwood area) in the Town of Midland.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$133,600
#1835 – Overhead Conductors & Devices	$ 29,300
Total Project Cost	$162,900

Start Date: 2013

In-Service Date: 2013

2013 Project 3: Fourth Street Pole Line: - Reliability/Renewal

Need: Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Wiring will be restrung. Existing transformer loading will be calculated and if required, a rebalance of the electrical load will be undertaken within the scope of this project.

The current pole line is in poor condition. Should an unplanned outage occur, increased costs may include overtime hours, increased costs to purchase the materials in an emergency situation and as well, potential lost revenues from lack of power. This plan is to prevent or reduce unplanned, lengthy outages by installing new infrastructure. Internal resources will be used for this project. Consequently, costs will be kept to a minimum.

The risks of not proceeding with the project include increased threats of major failure due to an old and potentially unreliable infrastructure. Additionally, in the event of an outage repairs will be costly due to increased hours spent at potentially overtime rates.

Scope: To replace 10 poles along Fourth Street from Ontario Street to Montreal Street

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$ 85,300
#1835 – Overhead Conductors & Devices	$ 12,000
#1850 – Line Transformers	$ 20,300
Total Project Cost	$117,600

Start Date: 2013

In-Service Date: 2013

2013 Project 4: Selected Pole Replacements: - Renewal

Need: Deteriorated poles at the end of their useful life in need of replacement before becoming a safety hazard to the public and/or plant failure resulting in related power outages and high cost of emergency repair or replacement. Poles were identified as high priority

Scope: 30 poles were identified to be replaced. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be replaced as required. Existing transformer loading will be calculated and rebalanced as required.

Capital Costs: Project costs of $84,100 were budgeted and recorded in account #1830 Poles, Towers & Fixtures

Start Date: 2013

In-Service Date: 2013

<u>2013 Project 5: Economic Evaluations – Developer Contributions – Customer Demand</u>

Need: The Development Contribution Projects are budgeted based on new customer connections for new subdivisions. These are developer installed projects. An Expansion Deposit has been agreed to for the projects and will be reduced annually during the connection horizon as the forecasted connections are connected. Upon energization, in 2012, Midland PUC expects to pay a transfer price of $100,000 for the assets installed by the developer.

Scope: Midland PUC has budgeted the transfer price to developer(s) of $100,000.

Capital Costs:

Acct # & Description	Amount
#1845 – Underground Conductors/Devices	$ 250,000
#1850 – Line Transformers	$ 140,000
#1855 – Services	$ 4,000
#1995 – Contributions & Grants	-$ 294,000
Total Project Cost	**$ 100,000**

Start Date: 2013

In-Service Date: 2013

2013 Project 6: Transformers – Renewal/Customer Demand

Need: In compliance with OEB accounting guidelines, transformers are capitalized at the time they are purchased rather than when installed. This expenditure represents the purchased cost of transformers for installation or inventory.

Scope: Transformers are purchased throughout the year in anticipation of future expected use to service new subdivisions, renewal projects and prudent backup requirements.

Capital Costs: Capital costs of $87,200 are budgeted under account #1850 Line Transformers for the year 2013.

Start Date: 2013

In-Service Date: 2013

2012 Project 7: Contribution and Grants

Need: Midland PUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. Midland PUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense account #5705 in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001. Article 410 of the APH provides for the accounting treatment of capital contributions. The appropriate asset account is debited and account #1995 is credited with the contribution. Consequently, no return is earned in the rate base for these contributions.

Scope: Projects will be designated by customers. Once Midland PUC has completed the required work, costs will be allocated to the appropriate general ledger asset account and customer deposits will be allocated to contributed capital account #1995.

Capital Costs:

Acct # & Description	**Amount**
#1830 – Poles, Towers & Fixtures	$ 48,000
#1835 – Overhead Conductors & Devices	$ 39,500
#1845 – Underground Conductors/Devices	$ 121,300
#1850 – Line Transformers	$ 71,400
#1855 – Services	$ 13,900
#1995 – Contributions and Grants	-$294,100
Total Project Cost	**$0.00**

Start Date: 2013

In-Service Date: 2013

2013 Project 8: Scada - substations

Need: Midland PUC's six substations are equipped with remote terminal units (RTU) which capture the real time amperages and voltages of the distribution feeders. The master station, which is located at the Operations Centre, is proprietary software called VMS and is outdated. Consequently, it is becoming difficult to maintain. A change to a Windows based platform will simplify the operational use allowing users to better record and store data. The current server will be required to be upgraded to an SQL server at the time of the SCADA software upgrade.

The benefits of SCADA include the efficiency of remote operation of the distribution which mitigates the impact of power outages through switching to alternate supply for isolated problems. In addition, Scada information facilitates efficient system operation including feeder balancing to minimize line losses etc.

Scope: To purchase Scada software and SQL server

Capital Costs:

Acct # & Description	Amount
#1920 – Computer Equip - Hardware	$ 12,265
#1980 – System Supervisory Equip.	$175,000
Total Project Cost	**$187,265**

Start Date: 2013

In-Service Date: 2013

<u>2013 Project 9: Harris CIS Upgrade – General Plant</u>

Need: Midland PUC will upgrade their billing software to the next version (V6.4) in 2013 through our billing co-operative Utility Collaborative Services Inc (UCS). Testing of this software throughout the marketplace will occur in 2011 and 2012 with the upgrade to the USC software taking place in 2013.

Scope: To upgrade billing software to comply with industry standards.

Capital Costs: Project costs of $55,000 are budgeted in account #1925, Computer Software

Start Date: 2013

In-Service Date: 2013

<u>2013 Project #10 – Miscellaneous Projects (Each Under Materiality)</u>

Need: Provision is made for urgent and necessary equipment replacement identified as a result of routine system inspections and customer service calls. Reactive renewal of assets with a "run to failure" replacement strategy are included in this category (eg. distribution transformers, underground cable). This category also includes replacement or adjustment to distribution system plant as required to accommodate customer demand work.

Also included in this category are small tool purchases, computer hardware and software purchases, meter and transformer purchases.

Scope: Multiple small jobs completed throughout the year, equipment purchases, all under $50,000 materiality.

Costs: Costs are identified as per individual project and USofA # in the following tables:

Table 2.3.11 Project 10: Miscellaneous Project Costs

PROJECT #10	AMOUNT		ACCOUNT #
Kabar Replacements	$	16,200	#1845
New Service Connections	$	13,000	#1855
Misc Capital Work	$	21,000	#1830/#1835
Tools	$	10,000	#1940
Meters	$	10,000	#1860
Hardware	$	9,900	#1920
Building	$	25,000	#1908
TOTAL	$	105,100	

APPENDIX A

LOAD STUDY

MIDLAND POWER UTILITY CORPORATION

BARKLEY TECHNOLOGIES INC.
UTILITY CONSULTANTS

42 KING CRESCENT
HUNTSVILLE, ONT.
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System Load Growth

And

Substation Expansion

Study

April 2011

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Section 1

Introduction

As the Town of Midland continues to grow in terms of urban density and planned developments, our responsibility as planners is to monitor this growth and to ensure that capacity is available on the distribution system to accommodate growth without compromising reliability and operational performance.

Midland PUC has been proactive in meeting this demand by systematically upgrading Municipal Substations and replacing small conductor. Increasing transformer size and upgrading switch gear has given the utility the ability to deliver a reliable energy source to new and existing customers.

The purpose of this study is to review the previous expansion studies and compare the recommendations to new forecast data as well as where Midland PUC is with regards to system improvements and expansions and determine what changes or adjustments may be required.

Section 2

Methodology

In previous expansion studies, power flow simulation was used to model load growth in the Town of Midland. This method is still the most effective way to inject forecasted development into an existing distribution system and study its effects. DESS (Distribution Engineering Software Solution) was used as a tool for this power flow simulation. Midland PUC has the DESS software and all files will be included as part of the deliverable for this project.

Study Data:

1. DESS model
2. Residential Development Data
3. SCADA Reports
4. Wholesale Metering Reports
5. Substation upgrade information

Procedure:

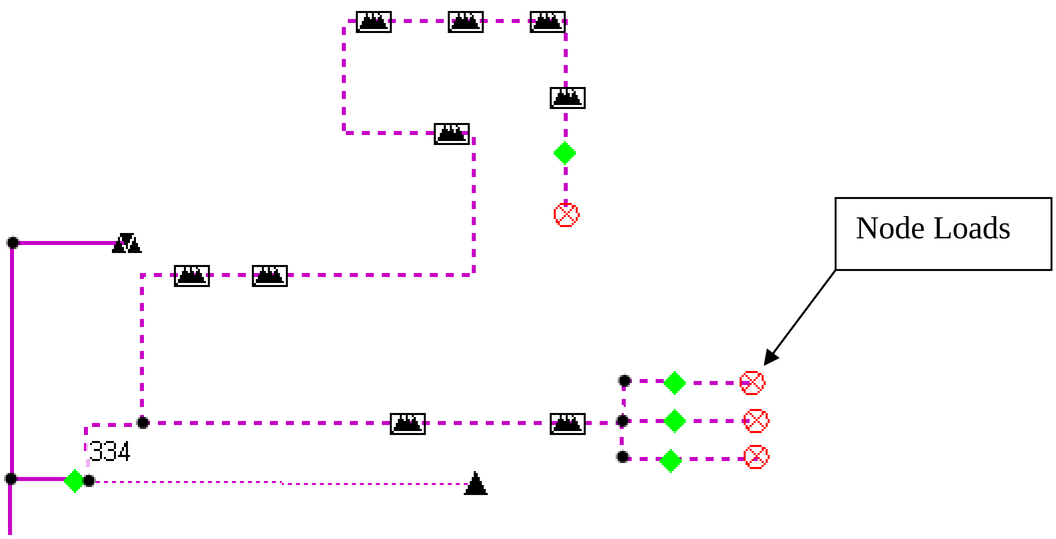
Power flow modeling requires up to date network data to accurately reproduce on the computer what is actually in the field. In addition to the network and equally as important is load data to allow the model to effectively and proportionately simulate the power flow – volts, amps, KW's and KVAR. Most planning exercises including loss reduction and load forecasting require that the system be modeled at peak values so the simulation shows the current at its highest while the voltage is at its lowest condition. Summer peak load conditions for 2010 were the highest that there has been for the last 5 years, providing issues for utility personnel but very good data for power flow modeling.

The SCADA data supplied was for September of 2010. The data was individual peak readings for the month and included per phase per feeder amps. The wholesale metering information provided peak KW's for the month of July. Wholesale metering was also requested for September.

The following were the steps used for the forecasting and expansion studies.

1. Update the DESS model
2. Update open points including removal of Dorian Sub from service as per existing switching configuration
3. Scale all substation loads based on September SCADA reports
4. Compare total load in DESS model to September whole sale metering.
5. The difference will be customer owned substation loads.

6. Scale customer owned station loads until the total system load matches the September wholesale peak (29.6 MW's)
7. Compare September wholesale metering (29.6 MW's) to July wholesale metering (40.3 MW's) absolute peak.
8. Now that the system has been proportionately adjusted, scale the complete system to absolute peak of 40.3 MW's.
9. Open and close switches on the model to reflect normal open points between stations. The available data required using SCADA data in an abnormal configuration for scaling and then putting the system back to normal to make the power flow in the right proportions.
10. Add all known forecasted development loads to the model, .based on the development map locations. Add them as node spot loads a below.



11. Run load flows to determine the effects on substations and feeders.
12. Analyze the results.
13. Develop reports

Section 3

Planned Development

Planned development refers to new potential load. Included in this forecast are developments that are:

1. Approved Development
2. Draft Approved Development
3. Application For Development

(See Section 7 “Reference Document “– Development Table – with notes)

This document provides the number of planned units to be added for each of the following categories:

1. Single Detached
2. Semi Detached
3. Townhouses
4. Apartments

The document does not describe the sq/ft of the units or the expected KW demand for each type of unit as was supplied for previous studies. An average KW per unit type was calculated using developments from previous Town of Midland planning studies.

(See Section 7 “Reference Document “– Development Table – with Calculations)

The final task is to determine where each development is and what corresponding feeder and station it will be fed from.

(See Section 7 “Reference Document “– Development_Map _Aug2010)

Section 4

Previous Recommendations

Please review expansion recommendations submitted in 2006 as they are still valid and should remain part of this report.

(See Section 7 “Reference Document “– Midland 2006 4kV Recommendations)

(See Section 7 “Reference Document “– Midland 2006 8kV Recommendations)

Section 5

New Study Results

Forecast Results:

The following is a comparison of forecasted load per substation in 2006 and the forecasted load per substation in 2010 and then in 2011.

Midland PUC Substation	2006 Future kW's	2010 Future kW's	2011 Future kW's
Brandon	2630	3515	3669
Dorian	4545	5705	6132
Fourth	5312	5439	5870
Montreal	4374	5159	5214
Queen	3984	5058	5059
Scott	3065	4209	3785
Firth's DS	8528	8737	6739
Total	32438	37822	36468

By comparing the three forecasts, the 2010 and 2011 expected load has continued approximately 1 MW to each station since the 2006 study except the 8kV Firth Substation forecast has been reduced.

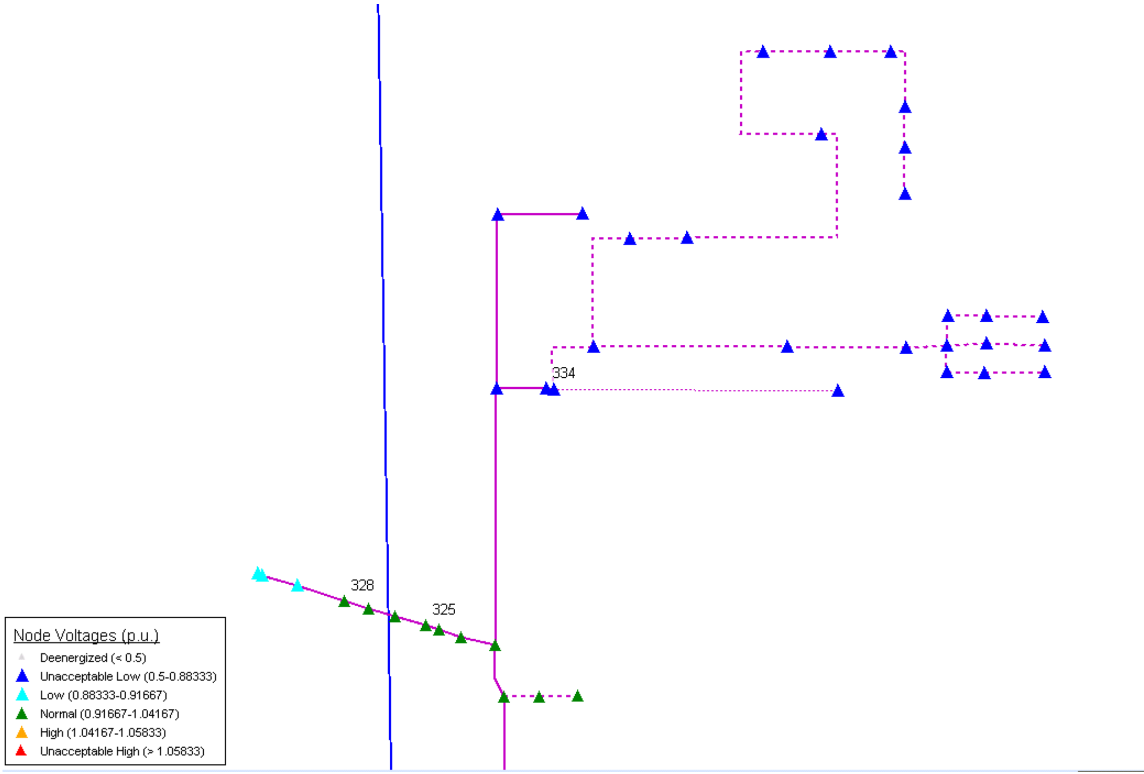
Review (Section 7 “Reference Document “– Sub Forecasted 2011) for load data for each station

Main Capacity Issues:

The majority of load growth is continuations of existing developments and for the most part can be absorbed by existing substations especially since most have been upgraded.

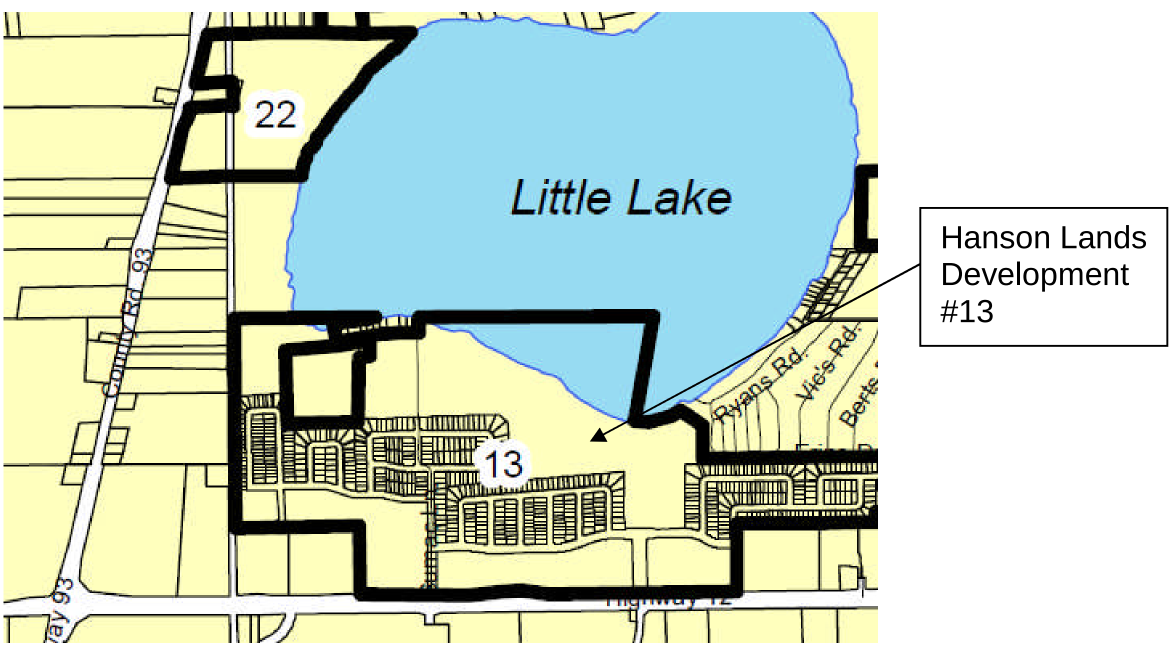
Bay Port Village

1.73 additional MW’s on Fourth St MS
This added load will bring the total for Bay Port Village to approximately 2.5 MW’s. The peak on the feeder will be 3.8 MW’s and the total station load will be 5.4 MW’s. This will overload the feeder conductor and the Fourth station transformer as well. Low voltage will also result at the development and surrounding customers.



Hanson Development

4.3 additional MW's on Firth DS at 8kV or on Brandon MS at 4kV



Section 6

Recommendations

Optimizations Studies
With the additional forecasted loads, distributing them between substations by opening and closing switches will provide the most efficient configuration and should be revisited as development continues.

Short Term

1. Distribute existing load between Montreal, Fourth and Queen through existing and proposed open points. An optimization has been performed specifically to address this issue taking into consideration transformer and feeder conductor sizes as well as the ability to back up each station. Upgrade conductor where required.
2. As load continues to grow at the Bay Port Village revisit the configuration periodically.
3. Distribute existing load between Scott, Dorian and Brandon using existing and proposed open points. The optimization has been performed to maximize the upgraded capacity of these substations. As the Tiffin developments along the shoreline and surrounding area evolves and load continues to grow, adjustments will need to be made to this configuration just like the north end of the system. Upgrade conductor where required.

Long Term

1. Previous recommendations that describe the Hanson Development on Hwy 12 and the operation benefits of feeding this area with 8KV is still a valid solution but since there is no current activity at the development the only activities to be invested should be planning and possibly some preliminary station property acquisition.
2. As the Tiffin development continues to use up capacity on Scott, Dorian and Brandon Substations, the need for a new substation in this vicinity as recommended in the 2006 study is still a valid suggestion. Optimizations and load flows will assist with determining the optimal location for a future station site.
3. The forecast for the Bay Port Village suggests that there would be enough demand for a small 44kV substation to feed this customer and remove it from the 4kV system. If this load continues to grow as planned a dedicated station either owned by the developer or possibly paid for by the developer will provide needed relief to Fourth St MS and allow it to give back up capacity to Montreal and Queen as it was originally planned to do.

4. Queen St. Substation is in a good position to not only provide support for Fourth and Montreal but can contribute capacity for the development along the water front north east of Scott St MS. To make sure Queen MS is able to effectively do this, upgrading the transformer size to 10 MVA is recommended. Queen St MS will be undergoing significant work on switchgear and ancillary equipment in 2011. It is a recommendation to upgrade the transformer in conjunction with this work as the station will be out of service to do this work anyway.

Section 7

Reference Documents

Development Table – with notes.pdf

Development Table – with calculations.pdf

Development_Map _Aug2010.pdf

Midland 2006 4kV Recommendations.pdf

Midland 2006 8kV Recommendations.pdf

Sub Forecasted 2011R1.pdf

Map Number	Owner	Total Units	Single Detached	Semi Detached	Townhouses	Apartment	Built/Under Construction	
Approved Development								
1	J. Stollar Construction	65	65	0	0	0	8	As market demand
2	J. Stollar Construction	31	31	0	0	0	26	
3	Little Lake Village Homes	38	0	0	38	0	7	
4	Helicon Properties	6	0	0	6	0	0	
5	Marina Park Resort	55	0	0	0	55	55	
6	Georgian Landing	41	0	0	41	0	0	
7	Captain's Cove	61	61	0	0	0	36	
8	Tiffin Pier	89	0	0	0	89	89	
10	Bay Port Village	63	63	0	0	0	25	
Draft Approved Development **								
7	Captain's Cove	104	0	0	0	104	0	2012
9	Mundy's Harbour	12	0	0	12	0	0	2012
10	Bay Port Village	507	0	0	177	330	0	2011 - 36 TH
11	LRG Midland	175	9	40	126	0	0	2011 - Phase I ± 50 un
12	Midland Bay Estates	92	92	0	0	0	0	2011 - Phase I ± 25 un
13	Hanson Development	1126	570	0	556	0	0	?
14	Midland Shores	145	145	0	0	0	0	?
15	Tiffin By The Lake	47	47	0	0	0	0	2011 - Start
16	Sunrise Pier	126	0	0	0	126	0	?
17	Pratt Homes	202	111	0	91	0	0	?
Application for Development **								
18	Sayward Investments	30	0	0	0	30	0	

*** all plans that are not approved are subject to change*

Potential Development Lands

	Zoning	Area
19	RT-H & RA-H	6.6 ha
20	R1-H	4.4 ha
21	R1-H	4.2 ha
22	R1-H & EP	17.4 ha
23	I	0.5 ha
24	R1-H & OS	6.5 ha

Zoning Symbols
RT - Residential Townhouses Zone
R1 - Residential Zone "R1"
RA - Residential Apartment Zone
OS - Open Space Zone
EP - Environmental Protection
"H" - Holding Provision

Date: May 2010
Location: P:\D02 Economic Development\Stats Package 2010\Residential_Development

			4.32345 kw	2.5 kw	3.3399 kw	2.7292 kw		
Map Number	**Owner**	**Total Units**	**Single Detached**	**Semi Detached**	**Townhouses**	**Apartment**	**Built/Under Construction**	
Approved Development			KWs					
1	J. Stollar Construction	65	65 281	0	0	0	8	As market demand
2	J. Stollar Construction	31	31 134	0	0	0	26	
3	Little Lake Village Homes	38	0	0	38 127	0	7	
4	Helicon Properties	6	0	0	6 20	0	0	
5	Marina Park Resort	55	0	0	0	55 150	55	
6	Georgian Landing	41	0	0	41 137	0	0	
7	Captain's Cove	61	61 264	0	0	0	36	
8	Tiffin Pier	89	0	0	0	89 243	89	
10	Bay Port Village	63	63 272	0	0	0	25	
Draft Approved Development **								
7	Captain's Cove	104	0	0	0	104 284	0	2012
9	Mundy's Harbour	12	0	0	12 40	0	0	2012
10	Bay Port Village	507	0	0	177 591	330 900	0	2011 - 36 TH
11	LRG Midland	175	9 39	40 100	126 421	0	0	2011 - Phase I ± 50 un
12	Midland Bay Estates	92	92 398	0	0	0	0	2011 - Phase I ± 25 un
13	Hanson Development	1126	570 2464	0	556 1857	0	0	?
14	Midland Shores	145	145 627	0	0	0	0	?
15	Tiffin By The Lake	47	47 203	0	0	0	0	2011 - Start
16	Sunrise Pier	126	0	0	0	126 344	0	?
17	Pratt Homes	202	111 480	0	91 304	0	0	?
Application for Development **								
18	Sayward Investments	30	0	0	0	30 82	0	

*** all plans that are not approved are subject to change*

5162 KWs | 100 KWs | 3497 KWs

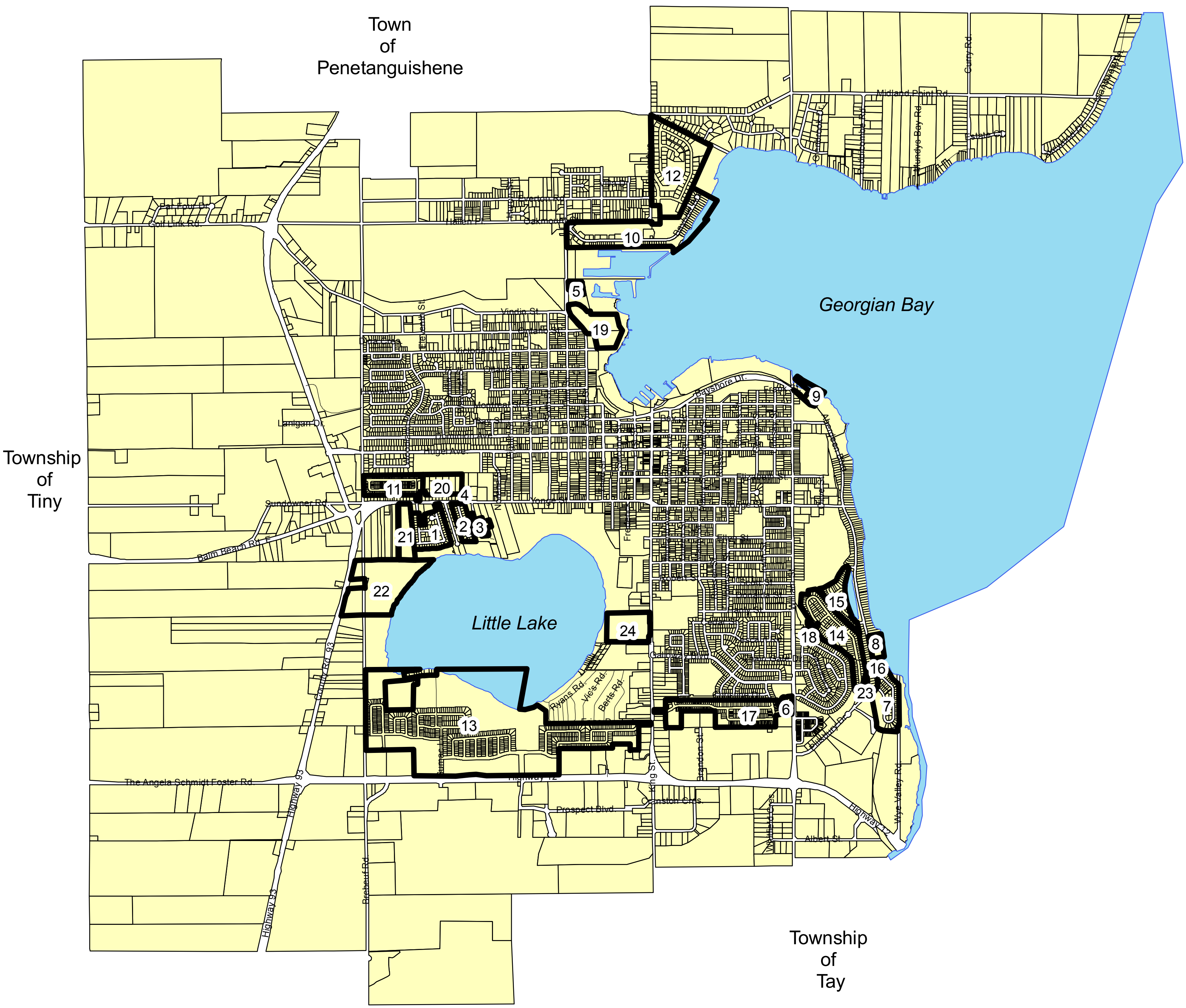
Potential Development Lands

	Zoning	Area
19	RT-H & RA-H	6.6 ha
20	R1-H	4.4 ha
21	R1-H	4.2 ha
22	R1-H & EP	17.4 ha
23	I	0.5 ha
24	R1-H & OS	6.5 ha

Zoning Symbols
RT - Residential Townhouses Zone
R1 - Residential Zone "R1"
RA - Residential Apartment Zone
OS - Open Space Zone
EP - Environmental Protection
"H" - Holding Provision

Date: May 2010
Location: P:\D02 Economic Development\Stats Package 2010\Residential_Development

Residential Development Projects



0 375 750 1,500
Metres

1:40,000

Date: May 2010
Created By: Midland Planning and Development Department
Location: P:/D02 Economic Development/ 2010/Residential_Development

Section 6

4kV Expansion

Long Term Option to load distribution between Fourth, Queen and Montreal

The two main criteria for selecting a location for a substation or upgrading an existing one are:

1. The ability to handle load growth.
2. The ability to move load to and from the station during routine maintenance or emergency conditions.

The majority of the 4kV load growth will take place along the waterfront and will continue to add to Dorian, Scott, Queen and Fourth Substations.
The transformers in both Scott and Fourth will need to be upgraded because of aging issues as well as loading issues. Increasing both of these stations from 3 to 5 MVA will provide needed capacity as well as the opportunity for relief on other stations.

Three factors limit the ability to take advantage of adding system capacity by upgrading station transformers.

1. The challenge of adding more feeders to the station structure or metal-clads.
2. Getting the feeders out and interconnected on the circuitry outside of the station especially in an urban area.
3. Tying circuitry to other stations for backup.

A new substation has been modeled on Yonge Street adjacent to lands where residential development will cause future loading issues on feeders coming from Montreal Sub and Queen Sub. Even though Montreal has capacity, there are no stations tied to it that can provide adequate backup long term. Adding a new station in this location will supply this backup to Montreal which can provide relief to Fourth Sub. Fourth Sub will require this relief as new development continues to grow to the northeast.

Section 5

8kV Expansion

The bulk of Midland PUC's power is supplied from Waubaushene TS at 44kV. The fact that Hydro One supplies approximately 2.5 Megawatts to Midland PUC from Firth's Corners DS, provides an interesting challenge. While not unique to surrounding utilities, 8.32/4.8kV is not compatible with Midland PUC's distribution voltage of 4.16/2.4kV. However, because of expanding boundaries and annexations, it is common for modern utilities to have several distribution voltages.

Firth's Corners DS is connected to Port McNicol DS by an open point on Hwy 12, providing options for moving load back and forth during emergencies.

A sizable portion of Residential and Industrial/Commercial development will take place on both sides of Hwy 12 that is currently fed by the 8kV from Firth's Corners. Since the substation is owned by Hydro One and it has very little capacity, any new load should be served from an alternative feed.

Extending the 4kV to this area will not only cause capacity issues, but it will make for a difficult integration with the existing 8kV. The Hanson Lands development has enough future load planned to justify a substation on its own. Industrial load growth on the south side of Hwy 12 will also make it difficult to feed at 4kV. This area is already an 8kV area so it makes more sense to install a new 8kV station and take advantage of existing station tie switches at both ends to feed during emergencies in either direction.

Midland PUC - System Load Growth

	Existing Stations				Recommended Stations		
	Transformer	2011	Future		Transformer	Future	
	Size	Load	Load	Load	Size	Load	Load
Station	KVA	KVA	KVA	%	KVA	KVA	%
Brandon	7500	3783	3669	49%	7500	5881	78%
Dorian	5000	3656	6132	123%	5000	3920	78%
Fourth	5000	4250	5870	117%	5000	3229	65%
Montreal	10000	4415	5214	52%	10000	6457	65%
Queen	5000	5096	5059	101%	10000	6457	65%
Scott	5000	3770	3785	76%	5000	3785	76%
Firth's DS	3000	2756	6739	225%	3000	0	0%
New 4kV Sub					5000	0	0%
New 8kV Sub					10000	6739	67%
Totals	40500	27726	36468		60500	36468	

Asset Management Plan Summary:

Midland PUC is an infrastructure-based business with its distribution system assets the key element in the delivery of electricity to its existing and new customers. Midland PUC's distribution assets range in age from new to over 60 years old.

Asset management is the professional management of physical infrastructure with a systematic methodology integrating best practices in all aspects of selection, design, construction, operation, maintenance, replacement and disposition. The goal is to use an Asset Management Plan to optimize the whole life business impact of costs, performance and risk exposures of Midland PUC physical assets. Performance of the assets is directly related to reliability of the distribution system which is another key regulatory and customer satisfaction measure second only to rates. In 2006, Midland PUC commissioned a substation study providing a plan for the replacement and/or upgrade of our 6 substations. Midland PUC did not have a formal asset management plan identifying other assets, such as poles, transformers, etc. and in 2010 and 2011 Rodan Energy Solutions Inc. was contracted to assist in the development of a comprehensive plan, along with the implementation of a GIS software based asset identification program. Accompanying this Schedule as Appendix B is a copy of our Asset Management Plan. It is important to note that Midland PUC's Asset Management Plan is in its early development stage. Midland PUC has completed a high level review of current assets and their age and has reviewed current strategies in dealing with maintenance and capital improvements. Also under review are the current and potential future activities expected to form the major parts of the Asset Management Plan in the future.

The plan for Substation assets was updated via a Load Study in 2011 with the two remaining substations being upgraded or replaced in 2012 and 2013.

Midland PUC has provided the forecast for 2014 and 2015 capital expenditures in Table 2.3.12 below. Amounts are reported under CGAAP. No changes to these capital expenditures will be required as a result of the transition to MIFRS. The annual replacement costs are engineering estimates only and the actual expenditure levels in the capital budgets could be adjusted based on project scope, prevailing construction costs and other outside influences (e.g. relocation requests, system expansions, etc.).

Table 2.3.12: 2014 & 2015 Capital Expenditure Forecast

Project #	Project Description		2014		2015
1	Victoria St. Pole Line Rebuild	$	65,100		
2	Quebec Street Pole Line - Fourth St to Eighth St	$	64,300		
3	Yonge Street Pole Line - William to Midland Avenue	$	134,500		
4	Foruth Street Pole Line - Bay St to Hugel Avenue			$	118,800
5	Queen Street Pole Line - Bay St to Gloucester St			$	57,300
6	M2 M4 Easement			$	62,100
7	Ten (10) Pad Mount Transformer Replacements 50KVA / 2400V	$	45,000	$	45,000
8	Five (5) Pole Mount Transformer Replacements 50KVA / 2400V	$	13,200	$	13,200
9	Selected Pole (30) Replacements (Various Locations)	$	84,100	$	84,100
10	Kabar Replacements - Four (4)	$	16,200	$	16,200
11	Economic Evaluations	$	100,000	$	100,000
12	New Service Connections During the Year	$	13,000	$	13,000
13	Misc. Capital Projects	$	21,000	$	21,000
14	Tools	$	10,000		10,000
15	Meters	$	10,000	$	10,000
16	Transformers	$	10,000	$	29,000
17	Vehicle	$	40,000		
18	Software Upgrade - Financial Statement Software	$	200,000		
19	Computer Purchases	$	10,000	$	10,000
20	Building and Equipment Upgrades	$	25,000	$	25,000
	TOTAL CAPITAL EXPENDITURE FORECAST	$	861,400	$	614,700

APPENDIX B

ASSET MANAGEMENT PLAN

RODAN

The Energy Solutions People

PUC

MIDLAND POWER UTILITY CORPORATION

Asset Management Plan & Strategy

Rodan Energy –Enabling Tomorrow's Smart Power Grid Today

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APPENDICES

Appendix A	Pole Risk Categories
Appendix B	Transformer Risk Categories
Appendix C	Conductor Risk Categories
Appendix D	Project Details
Appendix E	Project Schedule

Document Summary

Client Name	Midland PUC
Document Name	Asset Management Plan Report
Purpose	Asset Management Strategy for the 5-Year Period (2012 – 2016)

Revision History

Revision	Date	Reason
0.0	08-Sep-2011	Initial draft
0.3	04-Apr-2012	Revised after receiving further comments from Midland PUC.
1.0	23-Apr-2012	Final version after receiving comments from Midland PUC.

1. Executive Summary

This document outlines a course of action for Midland Power Utility Corporation's (Midland PUC) Asset Management Strategy for a 5-year period from 2012 to 2016.

Rodan recently completed a detailed asset inventory and condition assessment of the transmission and distribution network of Midland PUC for the purposes of developing a Geographic Information System (GIS) and Asset Management Strategy.

The outcome of this project provided an integrated mapping system and database to be used in future planning for asset replacements, technical upgrades, and ongoing asset management initiatives. With the data collected onsite, from existing resources, and using our industry knowledge regarding asset management practices, we developed an index that assesses the current status of assets within the network and a prioritization for future replacements. The tasks involved in this project are outlined below.

- Collect on-site field data and GPS locate all transmission and distribution assets
- Develop a GIS database
- Analyze and assess existing assets for future replacement
- Review projects and local developments with Midland PUC staff to ensure local/regional economic developments are accounted for.
- Utilize data to develop an asset management strategy

Table 1: Asset Inventory Summary

Asset Type	Qty	Multiplier	Units	Total
Poles	1846	1	Each	1846
Overhead Pole Mount Transformers	707	1	Each	707
Underground Pad Mount Transformers	385	1	Each	385
Overhead Switches	87	1	Each	87
Overhead Switches	151	3	Each	453
Pad Mount Switches	53	1	Each	53
Conductor – 14.4 kV Overhead – 3 Phase	12953	3	Metres	38859
Conductor – 14.4 kV (8.3) Overhead – 1 Phase	4960	1	Metres	4960
Conductor – 4kV Overhead – 3 Phase	46947	3	Metres	140841
Conductor – 4kV Overhead – 1 Phase	13825	1	Metres	13825
Conductor - 4kV Underground - 3 Phase	15240	3	Metres	45720
Conductor - 4kV Underground - 1 Phase	21357	1	Metres	21357

The inventory summary provides key values as indicated in Table 1. These values were further categorized in the study to provide future capital replacement of assets.

Midland PUC's primary focus was to ensure that the structural and electrical integrity of their assets was comparable or higher than other utilities throughout Ontario. This would ensure safety for customers, workers and the general public. A secondary focus of this study was to utilize industry standard asset life-cycles to define our criteria for determining asset replacement schedules. We have included key areas or circuit sections identified by utility personnel as areas where they recommended replacements or upgrades to the system.

We were able to obtain the number of years most assets have been in service and through field inspections and adjacent assets – determine the age of assets where no age was visible. This information combined with routine inspection and asset performance data allows us to model future asset replacement and can be used by Midland PUC as a tool for determining the future capital needs prior to asset failure.

Based on Rodan's review of Midland PUC's assets there are a number of assets that meet the age and condition degradation that should be planned for replacement within the next five years. Although the age of a number of other assets may suggest replacements will be required, we suggest continually (annual) monitoring and inspecting these assets, as they are still in adequate operational condition. It is standard practice that during a pole replacement, all attached equipment is reviewed for replacement at the same time.

The inventory and inspection of Midland PUC's asset base returned results typical of most Ontario based utilities. Although age can be used as an indicator for asset replacement, it should be only one of many assessment variables in addition to condition, location, and servicing to the customer base are to be used to ensure the full service life of each asset is utilized completely. There are a number of recommendations within this report that indicate an integration of inspection and maintenance records with the GIS will prove beneficial for decision making on both discretionary and non-discretionary capital projects in the future. For the short term (1-5 years), we have identified a number of projects requiring attention:

- Re-conductoring and pole replacement
- Individual asset replacements
    - Immediate (Within one year)
    - Planned (1-5 years)
- Individual transformer replacements
    - Immediate (Within one year)
    - Planned (1-5 years)
- Maintenance and repair

- Additions to the System
- Asset Nomenclature

Initial estimates suggest a capital requirement for 14 capital projects and 11 maintenance projects between 2012 and 2016. We recommend that these projects be reviewed by Midland PUC management as part of their capital planning and project selection process. This would allow for ranking and re-prioritizing the projects to provide the basis for the financial planning model to be developed for the short term. The project costs are for budgetary purposes only. Should Midland PUC wish to pursue the implementation of these projects, a detailed cost estimate and/or price quotation from one or more vendors based on detailed scope of work including equipment specifications is necessary.

A list of capital projects between 2012 and 2016 is summarized in Section 9: Identified Projects.

2. Introduction

Midland PUC provides electricity service to the Town of Midland. The distribution system consists of two primary voltages with 44kV feeders, feeding 39 Stations (6 Midland PUC Owned and 33 customer owned) at 4160/2400V, with a total of 23 feeders.

Table 2: Substation / Municipal Station Summary

Name	Civic Address	Voltage	Feeder Name
Brandon	850 Brandon Street	4160/2400	B1
			B2
			B3
Dorion	824 William Street	4160/2400	D1
			D2
			D3
Fourth	67 Fourth Street	4160/2400	F1
			F2
			F3
			F4
Montreal	809 Montreal Street	4160/2400	M1
			M2
			M3
			M4
			M5
Queen	187 Queen Street	4160/2400	Q1
			Q2
			Q3
			Q4
Scott	328 Scott Street	4160/2400	S1
			S2
			S3
			S4

The Ontario Energy Board issued a review[1] of Ontario's Electricity Local Distribution Companies on the status of processes for managing capital assets. The review identified four key processes that are consistent with good asset management practices:

- Inspections and Maintenance
- Capital Expenditure planning
- Capital Financing
- Information Management

[1] Review of Asset Management Practices in the Ontario Electricity Distribution Sector, March 10, 2009, http://www.oeb.gov.on.ca/OEB/_Documents/Audit/Report_Asset_Management_Practices.pdf

Inspection and Maintenance

The inspection process is used to support maintenance and capital planning. Physical asset condition and asset performance can be determined only by actual inspection and testing. It is a process that needs to be routinely performed, and information collected and updated. This leads to improved information, and allows for making important decisions when evaluating trade-offs between cost and performance.

With the inspection results, a utility may then make conscious and informed decisions about the level and frequency of maintenance. Objective analysis of actual reliability results is a key element in determining the level and frequency of maintenance.

Capital Expenditure

In order to select projects (e.g. self construct, contractor construction, etc) it is necessary to integrate the needs for renewal or development of the utility asset base with financial resource planning and acquisition. Projects may also be driven by safety or health concerns, customer growth, regulatory (legal/statutory) requirements, and those related to decreasing service quality or reliability. Utility management must have the information necessary to rank any project to determine the need to schedule immediately, versus those that may be postponed or deferred. Each significant project must be supported by appropriate documentation, such that a business case can be prepared identifying the cost and the expected benefits.

Capital Financing

A utility must balance their total capital spending with their availability of funds. There is often a trade-off between the availability and the level of spending. To support their capital plan, a utility must have access to sufficient capital at a reasonable cost. It is necessary for the utility to target a reasonable debt to equity ratio, that is maintaining a proportion of equity and debt used to finance the utility’s assets. The target debt to equity ratio determines the amount of capital spending in excess of funds generated from operations (including depreciation) that need to be funded by net new debt or new equity.

Information Management

The organization of, delivery of, and control over information is a key process for a utility to function. This information is the utilities asset data, and maintained in a database such as a (GIS). The data and the accuracy of the data are important in supporting each of the key processes of inspection, maintenance, capital planning and financing. The GIS must share a common base, and be accessible across all functional departments.

3. Objective

The objective of this exercise was to develop the asset management strategy for Midland PUC's transmission and distribution assets. The project involved a number of electrical utility experts to identify key components of the system that require short-term attention, as well as outline future asset replacement schedules and methods for the continuous maintenance of the asset registry.

The principles used to develop this document were derived from:

- Acts, Regulations, Codes and Guides
- General Public and Worker Safety
- Good Utility Practices
- Overall System Reliability and Customer Satisfaction

However, this strategy should be reviewed on an annual basis to ensure adjustments are accommodated with respect to the following:

- Regulatory changes
- Performance Reviews
- Health and Safety Assessments
- Asset Condition Assessments / Inspections

4. Scope

The development of the asset management strategy involves the analysis of the recent asset inventory / condition assessment data, as well as current and future capital construction plans from utility staff. The following asset groups and sub-groups were inventoried, assessed for current physical condition, categorized based on age, and reviewed for scheduled replacement:

- Transmission
    - Poles/Towers/Fixtures
    - Conductors
    - Switching Devices
- Substations / Metering Stations
    - Fencing
    - Grounding Grid
    - Reclosers / Switching Devices
    - Power Transformers
    - Switch Gears
    - HV/LV Cables, Insulators, and Duct Banks

    - Super structure – fuses, grounding, and lightning protection
- Distribution
    - Poles/Towers/Fixtures
    - Conductors
        - Overhead
        - Underground
    - Switching Devices
    - Transformers
        - Overhead (Pole Mounted)
        - Underground (Pad Mounted)
- Secondary
    - Poles/Towers/Fixtures
    - Conductors
    - Metering Points

5. Tasks / Deliverables

The tasks and deliverables for the asset management strategy were defined as follows:

- Complete field inventory data collection and asset condition assessment by a qualified/experienced lineman/journeyman.
- Conversion of field collected data into a AutoCAD Map 3D compatible Geographic Information System
- Summarize for each asset category a listing of:
    1. Potential issues
    2. Assets exceeding their life expectancy
    3. Assets categorized based on their relativity to the system (ie. Transmission, 3 Phase Distribution, Single Phase Distribution, Secondary/Servicing)
- Identify future needs outlined by local utility staff.
    1. Desired system enhancement projects
    2. Expansions due to local development projects
- Utilize asset inventory data within a system modeling software solution to provide technical suggestions for improvements to the system.
- Prioritize high-level deterioration models; thus, providing a list of capital replacements with respect to age, condition, system impact, and social/economic influence.
- Develop recommendations for improvement and a strategic plan for asset replacements.
- Provide a schedule for asset replacement for all four categories:
    1. Substations

2. Transmission
3. Distribution
4. Secondary

- Priority ranking of projects
- Recommendations for ongoing updates and use of the asset management strategy.

6. Pole Structure Assets

Pole Assets - Condition Assessment
Midland PUC's asset base includes 1791 wood, 18 concrete, and 37 steel poles.

In conducting life cycle analysis, no variable is more critical than the value assigned to the expected life of a product. Although wood pole systems may last longer than the periods perceived by most utilities, we have provided a series of expected life cycles for the various structure materials utilized within the Midland PUC network. The values assigned for each structure material life expectation were then grouped to provide an age ranking value. This age risk rating value was then applied to the GIS asset inventory information. This value can be used to calculate and identify the structures within the system that require more frequent monitoring and approximate timelines for replacement.

We also identify the periods at which the majority of the structures will need replacement. Note that some structures will exceed the expected life and typically 2%-4% of the structures that have exceeded their expected service life will need to be replaced annually. Ongoing inspections and monitoring will allow Midland PUC to determine which structures fall within this 2%-4% on an annual basis.

Throughout the life cycle of most structures, groundline decay is the predominant cause for failure.

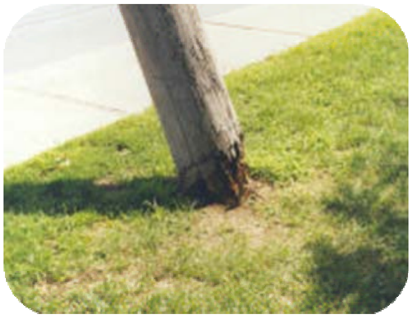

Figure 1: Groundline Decay

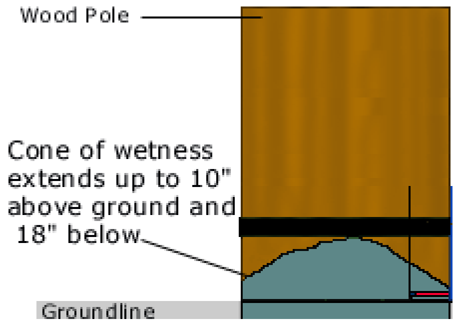

Figure 2 : Groundline Wetness Cone

However, in certain conditions other influencing factors contribute to pole failure:

- Pole top decay (stove piping)
- Decay at connections (bolt and pin holes for cross arms, insulators, equipment, and attachments)
- Weak segments (typically where knots are found)
- Splitting of pole tops
- Excessive weathering

Figure 3: Pole Top Decay / Weathering

We have excluded the following issues that cause structure failures and premature structure failure from our calculated values:

- Woodpecker damage
- Ant damage
- Mechanical damage (due to vehicular impacts)
- Line upgrades / Additions of Circuits
- Reroutes / Relocates

<u>Note:</u> If any of the above conditions existed in the field and were considered a safety concern – the location and details of the pole were immediately reported to Midland PUC for repair/replacement.

Throughout the asset inventory and condition assessment, the year of manufacture was recorded if it was available. The majority (70%) of the structures had a year stamp indicating the year of shipping from the manufacturer. In the event that a date stamp could not be located, an assumed year of manufacture was assigned at the same year of the oldest adjacent pole structure. Although we recognize this may not be the year of installation, we have assumed that in the majority of cases the year of installation is the same or within a few months from the date of purchase.

Age Risk:

Asset depreciation based on age is a useful tool for predicting future need; however, many assets will be structurally sound and operational for several years beyond expected life. These assets should be routinely inspected and monitored to ensure they are suitable for ongoing service.
A variety of studies and field collected data indicate that western cedar and steel structures have on average a longer life cycle than poles of other wood species. The following tables indicate the values applied in this study to calculate the age risk rating for various pole material types and wood species.

Table 3: Pole Material – Average Expected Life

Pole Material	Average Life (Yrs.)[5, 11]
Western Cedar (WC, WCC)	60
Southern Pine (JP, JPP, RP, RPP, SPP, SYP, Wood)	40
Douglas Fir	35
Ponderosa Pine	40
Lodge Pole Pine	35
Concrete	80
Steel	60
Composite	80

Table 4: Pole Material – Age Risk Category

Pole Material Type: - All Other Wood Types	
Age - Risk Rating Category	Year Grouping
1	< 5 yrs
2	5-9 yrs
3	10-19 yrs
4	20-29 yrs
5	> 30 yrs

Note: Age Risk categories are assigned to each pole asset found in Appendix A

[5] Dennis Hayward, "Wood Poles: How Long Do They Last? 30..45..60…100 Years? It Makes a Difference", Wood Pole Newsletter, vol.20, July 1996
[11] Ontario Energy Board – Kinectrics Inc., "Asset Amortization Study for the Ontario Energy Board", July 8, 2010

Table 5: Pole Material – Age Risk Category

Pole Material Type: - Western Cedar, Steel	
Age – Risk Rating Category	**Year Grouping**
1	< 10 yrs
2	11-24 yrs
3	25-40 yrs
4	41-54 yrs
5	> 55 yrs

Note: Age Risk categories are assigned to each pole asset found in Appendix A

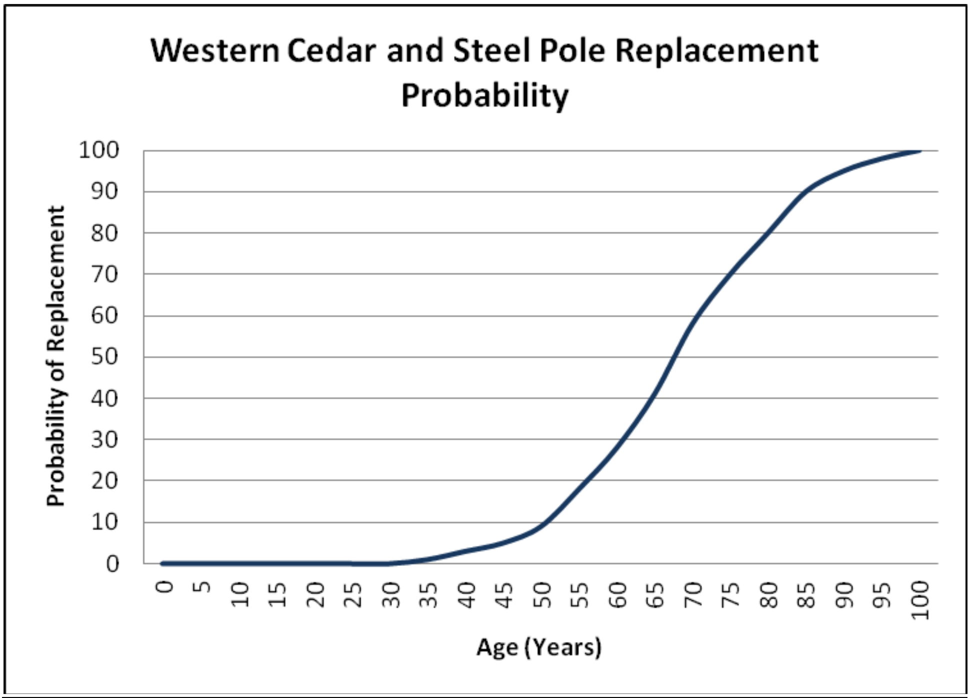

Figure 4: Western Cedar and Steel Pole Replacement Probability*

Note: Curve is for assisting with trending purposes only, and does not reflect the condition of Midland PUC poles.

**Source:* [5]Dennis Hayward, "Wood Poles: How Long Do They Last? 30..45..60…100 Years? It Makes a Difference", Wood Pole Newsletter, vol.20, July 1996

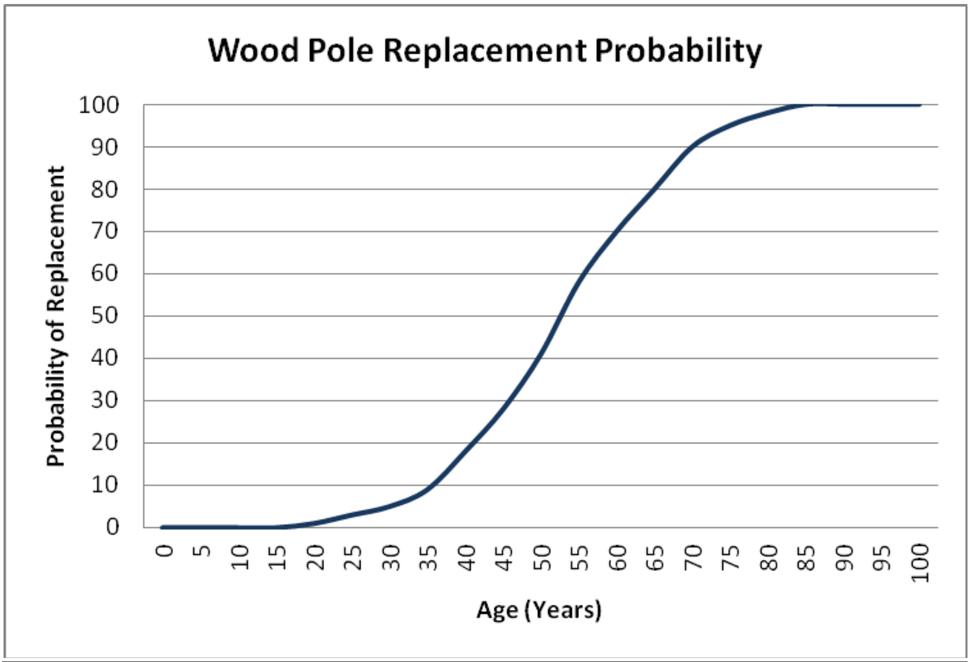

Figure 5: Wood Pole Replacement Probability*

Note: Curve is for assisting with trending purposes only, and does not reflect the condition of Midland PUC poles.

Using the asset inventory details and applying the age risk category to each structure, the calculated Age Risk for the Pole assets are as follows:

Table 6: Midland PUC - Distribution of Poles Based on Calculated Age Risk Category

Calculated Age Risk Rating Category	Quantity
1	377
2	122
3	353
4	339
5	655
Total	1846

Note: Individual pole asset detail information can be found in Appendix A

Condition Risk:

A visual inspection was completed by a qualified lineman/journeyman with an assignment of Poor, Average, or Good. At the same time a list of any damages was also recorded with respect to the pole, utility attachments, guys/anchors, and equipment. The issues that the field personnel identified were separated and itemized for inclusion in the maintenance budget. Any safety concerns were immediately reported to Midland PUC personnel. A hammer test was also conducted at the pole base as a basic means of detecting butt rot conditions. Based on the visual inspections and the hammer test, each structure was categorized with a 1-5 condition rating.

Table 7: Pole – Condition Risk Categories

Pole Condition: - All Wood Types			
Risk Rating Category	**Hammer Test**	**Visual Condition**	**Damages**
1 & 2	No Decay	Good	None
3	Some Decay	Average	Loose Hardware / Excessive Weathering
4	Significant Decay	Average	Loose Hardware / Excessive Weathering
5	Extreme Decay	Poor	Split / Pole Top Decay

Note: Condition Risk categories are assigned to each pole asset found in Appendix A

Location Risk:

In order to aid Midland PUC in prioritizing replacement programs the overall system reliability and continuity of service must be considered. Having a GIS provided the ability to apply a location risk rating to each asset. We determined that the location risk rating could be sub-divided into two categories; one pertaining to the entire system, and the other pertaining to the servicing of critical (public health/safety) and major economic customers. Tables 8 and 9 indicate the risk rating criteria used for the overall system and customer servicing/business risks. Figure 7 provides a visual schematic explanation of the criteria used to categorize each pole/tower/fixture asset with respect to its locational relevance to the system.

Table 8: Pole – Location Risk Categories

Pole Location: - All Wood Types: - Location Risk	
Risk Rating Category	**System Location**
1	Secondary / Servicing
2	Single Phase
3	Three Phase
4	Multiple Circuit / Close Proximity to Substation
5	Transmission

Note: Location Risk categories are assigned to each pole asset found in Appendix A

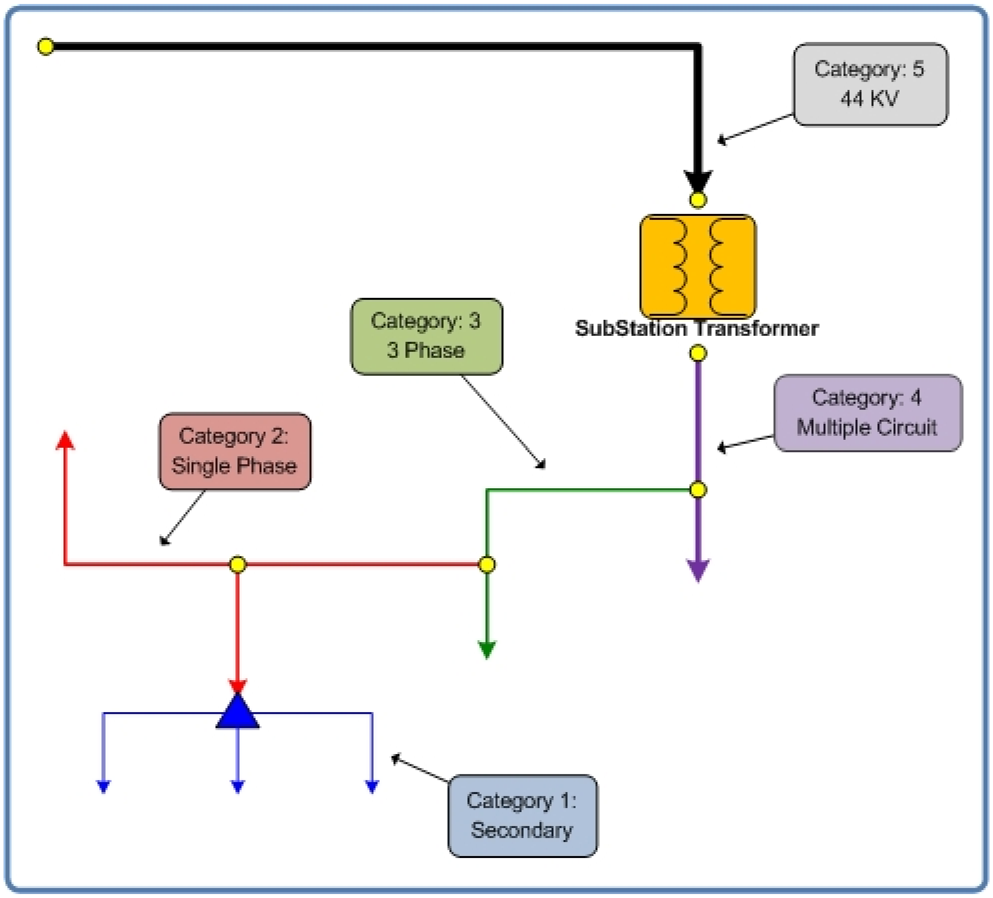

Figure 6: Location Risk Category Schematic

Table 9: Pole – Social/Economic Risk Categories

Pole Location: - All Wood Types: - Business Risk	
Risk Rating Category	**System Location (With Respect to Customer Base)**
1	End of Single Phase Run or Secondary
2	Three Phase
3	Close Proximity to Substation
4	Services One Critical Customer of Major Economic Customer
5	Services Multiple Critical Customers or Major Economic Customers

Note: Business Risk categories are assigned to each pole asset found in Appendix A

Pole Risk Categories:

The information regarding the supporting structures at Midland PUC that have been installed, maintained, and replaced at various periods throughout the existence of the utility is contained in Appendix A. During times of economic development and community growth, greater volumes of poles were installed than other periods. This trend is common in most utilities. However, the replacement strategy will in most cases mirror the initial construction schedule. Midland PUC required a means of inventorying all assets and determining a short and long term plan for monitoring, maintaining, and replacing assets. Appendix A provides this inventory listing and assigns numerical ratings for the following variables (according to industry standard life cycle models):

- Age Risk - The age of the asset with respect to the expected asset life.
- Condition Risk - The physical condition of the asset or any noticeable damages.
- Location Risk - The location of the asset with respect to the circuits – Transmission, Distribution, Secondary
- Business Risk - The location of the asset with respect to critical customers (i.e. does this structure support critical customers?)

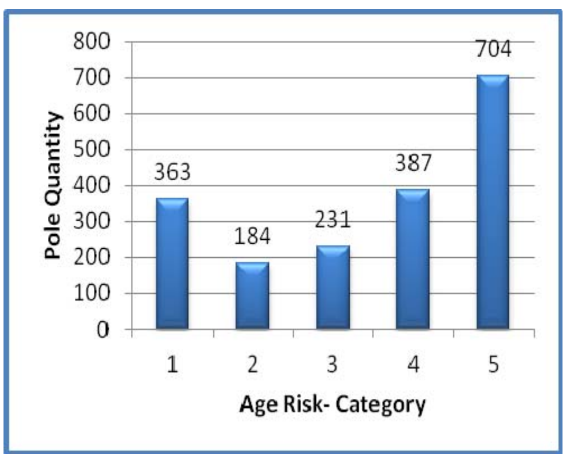

Figure 7: Pole Quantities Based on Age Risk Category

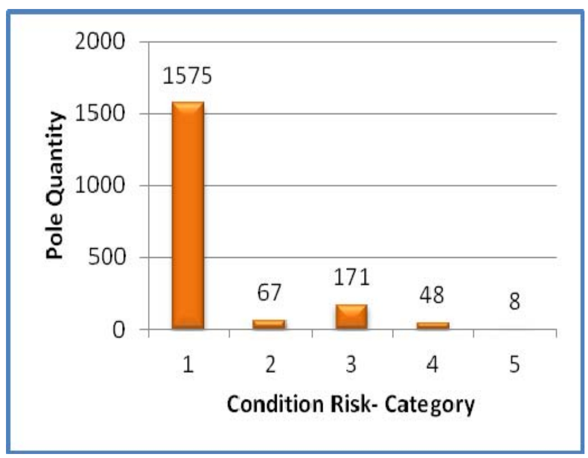

Figure 8: Pole Quantities Based on Condition Risk Category

Note: Age and Condition Risk categories are assigned to each pole asset found in Appendix A

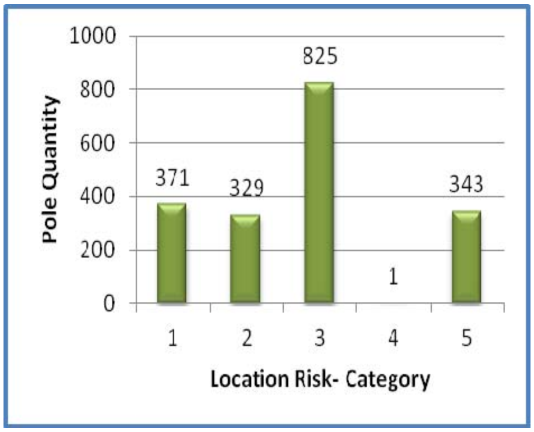

Figure 9: Pole Quantities Based on Location Risk Category

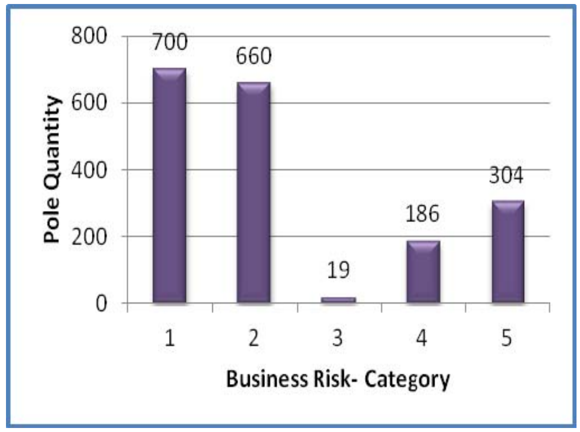

Figure 10: Pole Quantities Based on Business Risk Category

Note: Location and Business Risk categories are assigned to each pole asset found in Appendix A

A review of the categorized data revealed an inverse relationship between age of assets and their corresponding condition. In order to prioritize the pole structures in need further inspection (scientific or visual), we calculated an overall weighted risk rating using the aforementioned risk categories:

Overall Risk = [Age Risk (20%) + Condition Risk (50%) + Location Risk (20%) + Business Risk (10%)] x 4

Equation 1: Pole Risk Weightage Formula

Using this value as an attribute of the poles, we can utilize the GIS to thematically color code the poles in a GIS, providing the specific locations of structures determined to be a calculated risk.

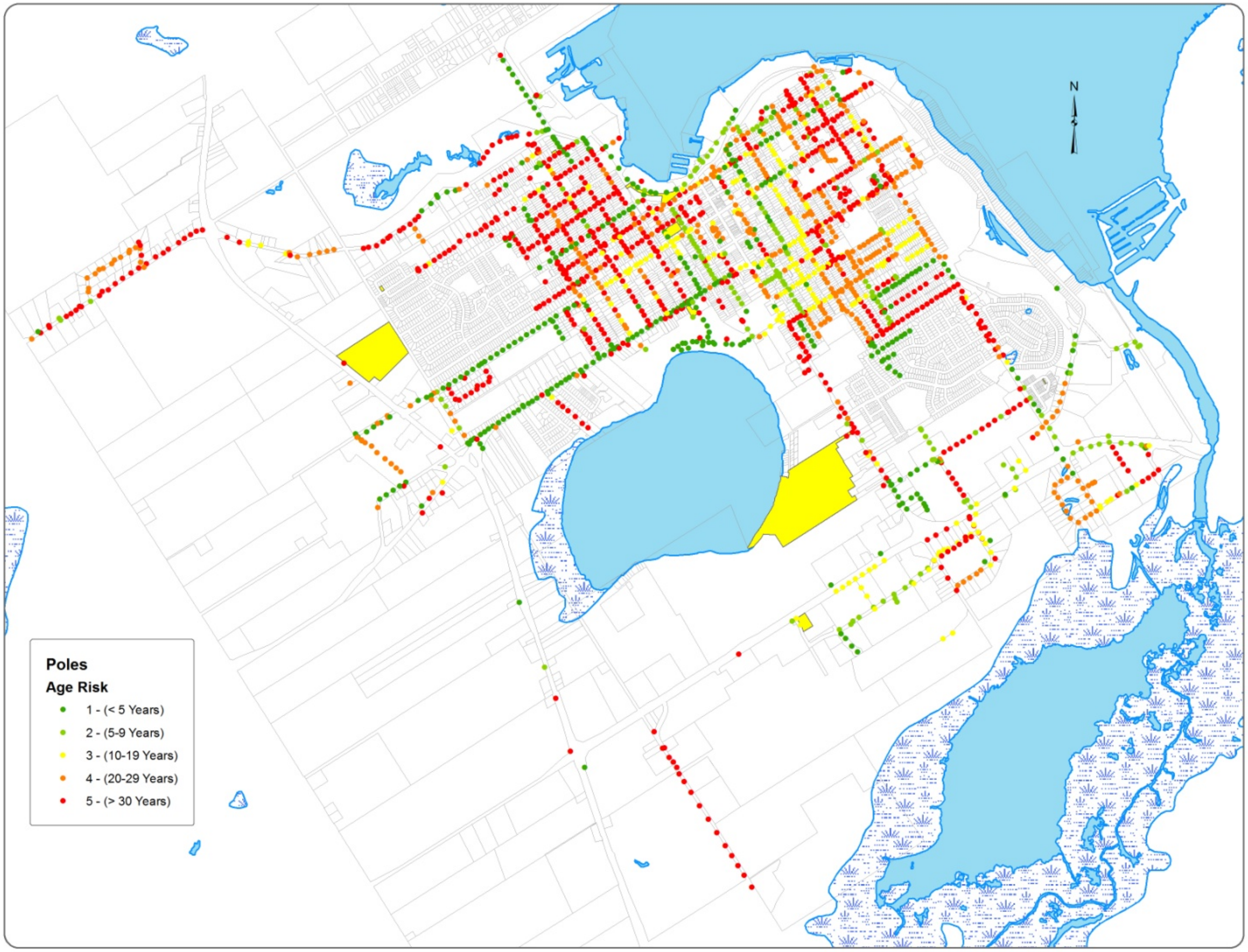

Figure 11: Town of Midland – Pole Age Risk Category Map
Note: Age Risk categories are assigned to each pole asset found in Appendix A

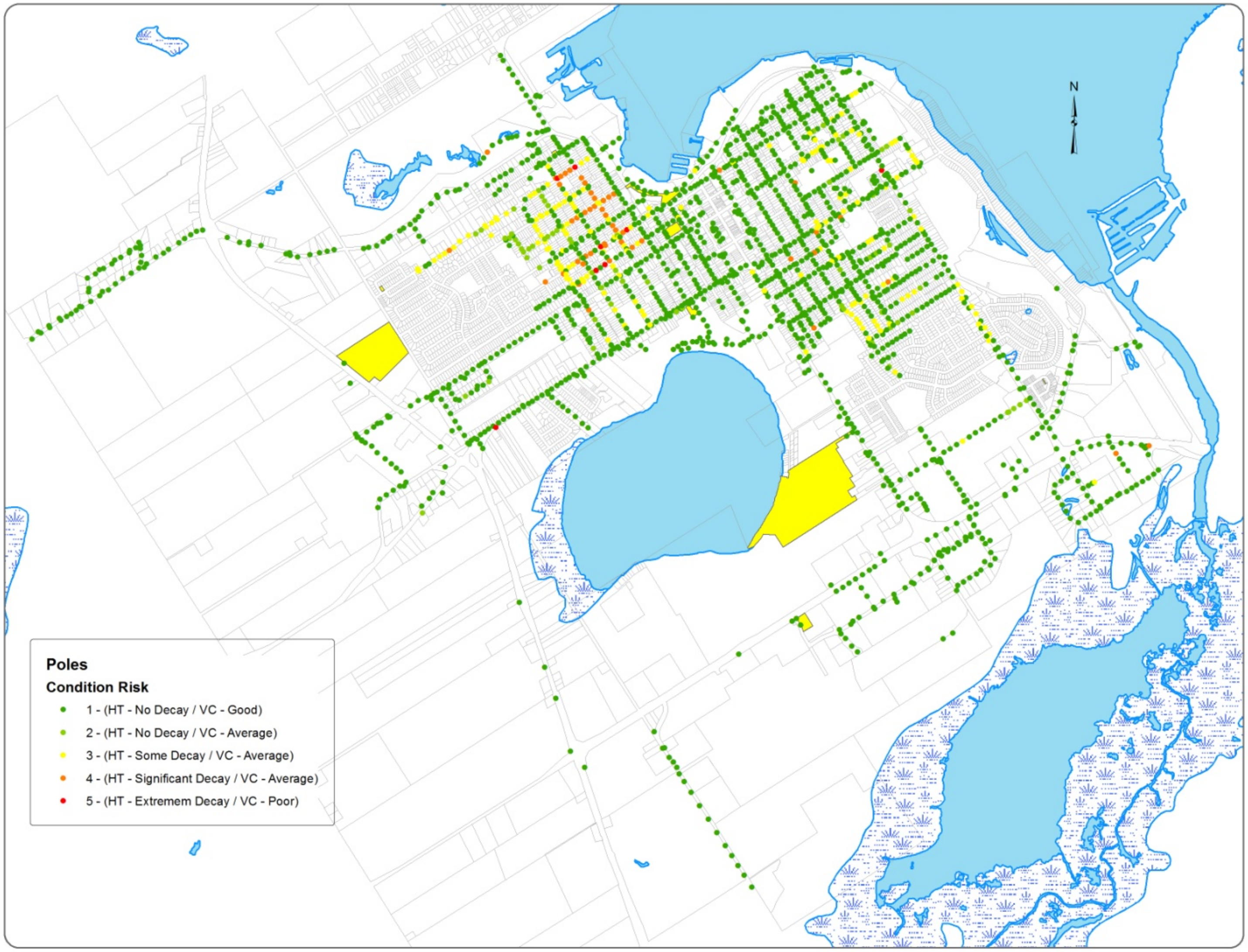

Figure 12: Town of Midland – Condition Risk Category Map

Note i: Condition Risk categories are assigned to each pole asset found in Appendix A

Note ii: HT = Hammer Test, VC = Visual Condition

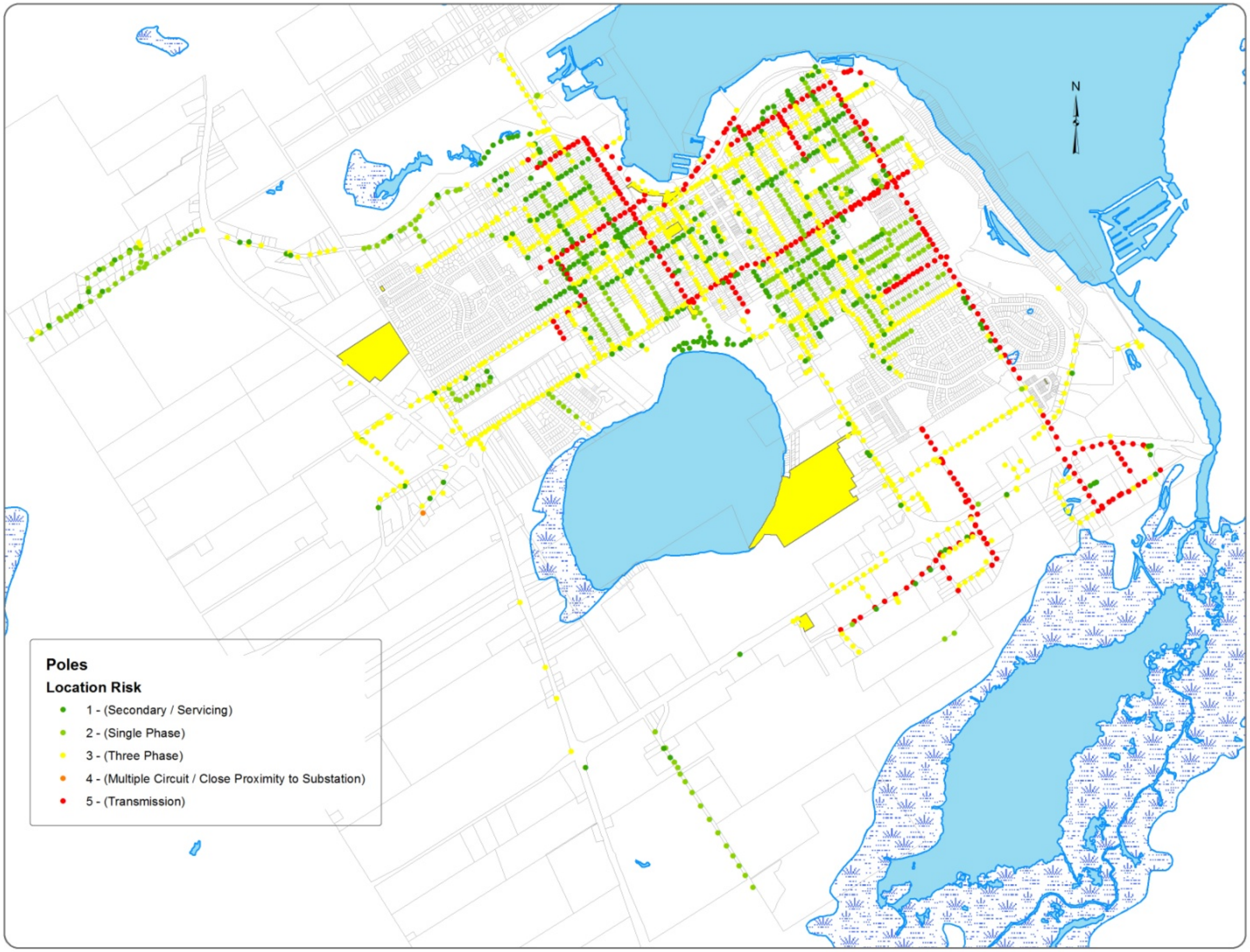

Figure 13: Town of Midland – Location Risk Category Map

Note: Location Risk categories are assigned to each pole asset found in Appendix A

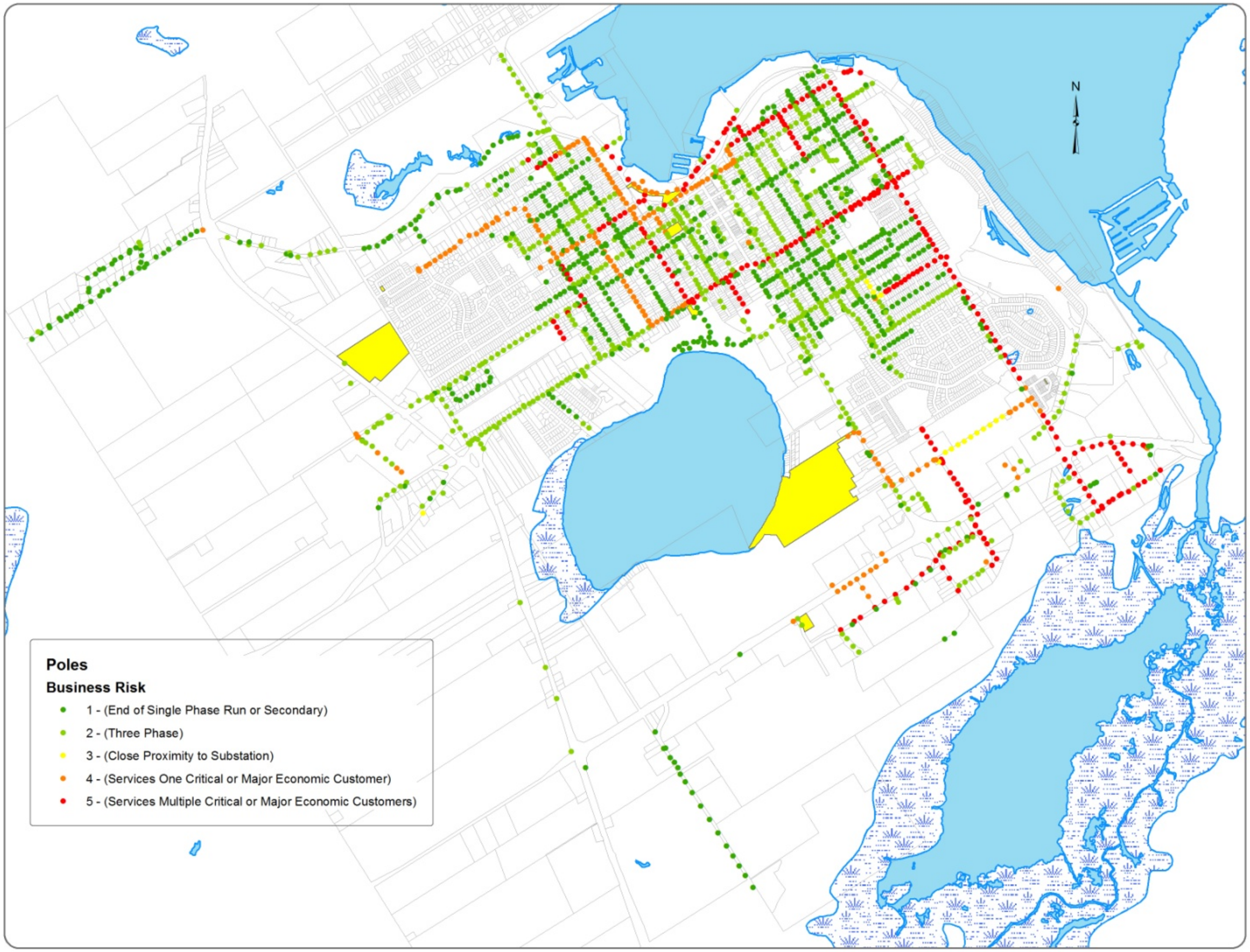

Figure 14: Town of Midland – Business Risk Category Map
Note: Business Risk categories are assigned to each pole asset found in Appendix A

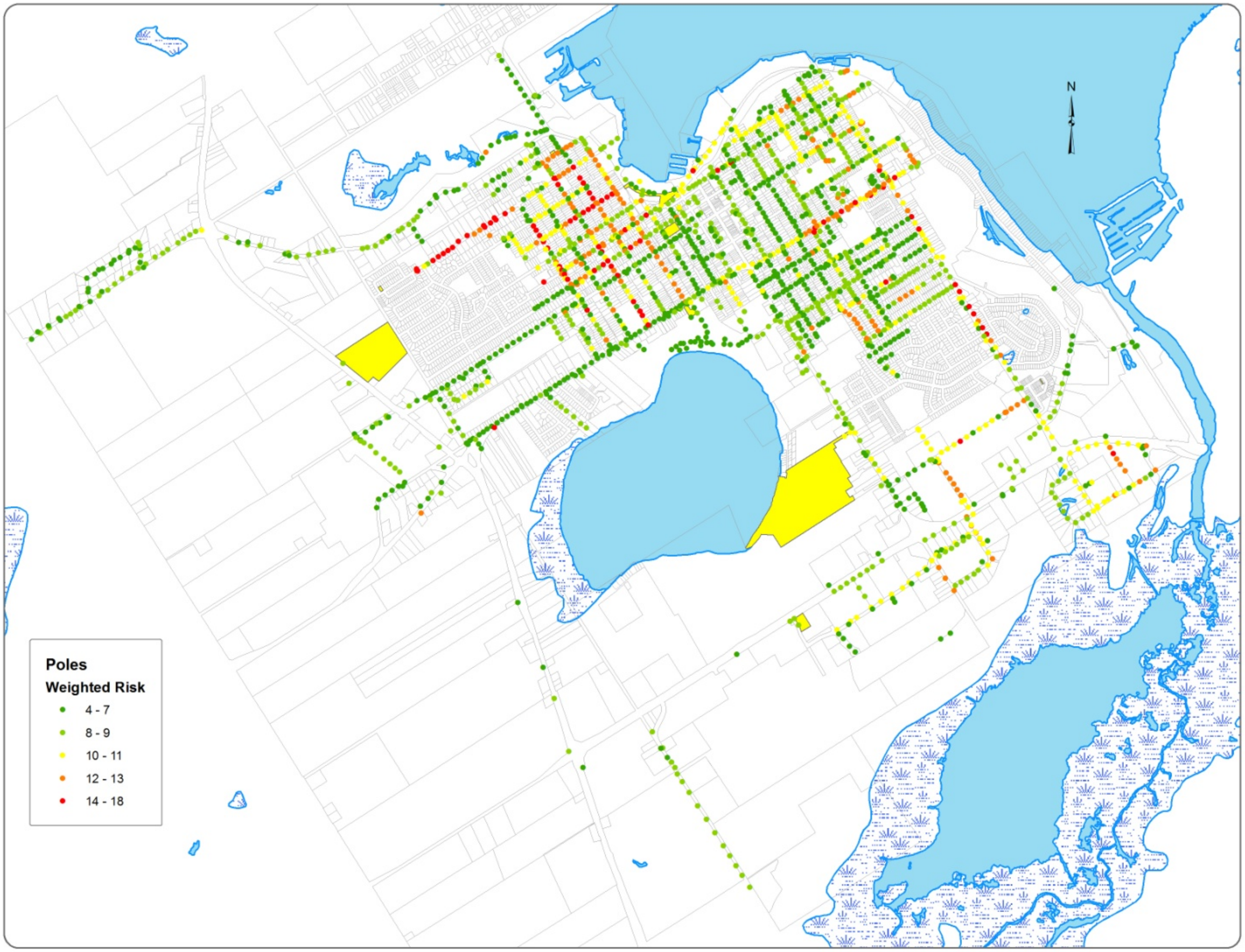

Figure 15: Town of Midland – Weighted Risk Category Map
Note: Weighted Risk categories are assigned to each pole asset found in Appendix A

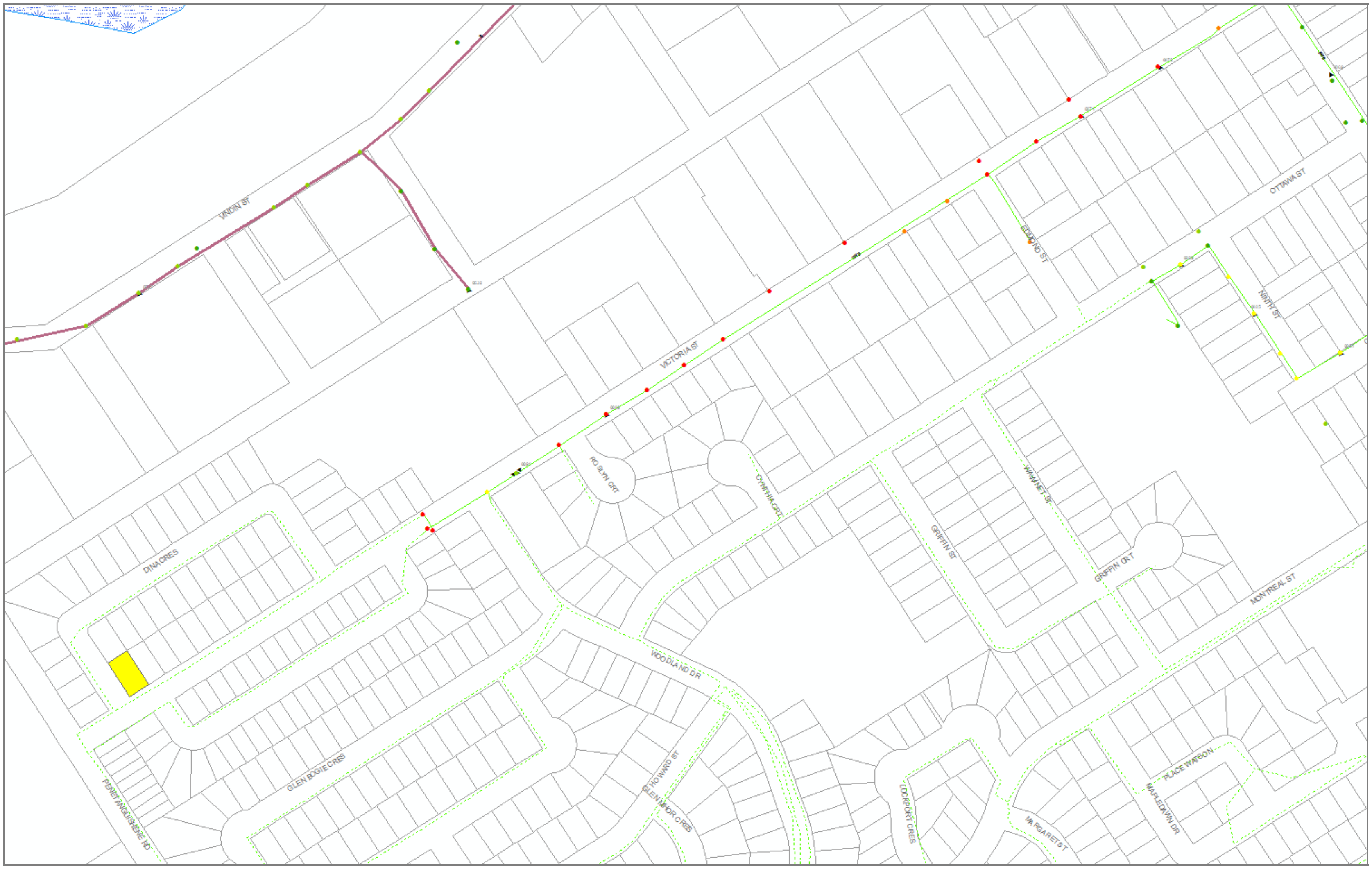

Figure 16: Victoria Street - Pole Monitoring/ Planned Replacement

Note: Weighted Risk categories are assigned to each pole asset found in Appendix A

Victoria St. – Pole Monitoring/Planned Replacement:

Based on the weighted risk methodology for monitoring/ replacement of poles, a section of the line at Victoria Street turned out to have a Weighted Risk score of 14 (replace/ monitor closely). A look at the underlying risk scores revealed the following:

Age Risk:	5 (Poles installed in 1950s and 1970s, > 30 years of age)
Condition Risk:	Majority are 3 (Average) – Some Decay with Poor-Average visual condition
Location Risk:	All poles in this stretch are a risk rating of 3 (Support a 3 phase circuit)
Business Risk:	All poles in this stretch are a risk rating of 4 (Provides service to one critical or major economic customer)
Weighted Risk:	14 = [Age Risk (20%) + Condition Risk (50%) + Location Risk (20%) + Business Risk (10%)] x 4

The planned replacement notations in the appendices indicate that this section should be closely monitored and identified as a section for future replacement. Although there is not an immediate need to replace this segment of line – the combined factors that may be used to identify and prioritize assets for future replacement are identifying this section of line as being relatively important and of future need for replacement.

Pole Capital Requirements:

The information for the capital requirement for the poles for the next five years is contained in Appendix A. These lists identify the structures that require replacement within one year as well as those pole structures that may require replacement and are determined to have reached or exceeded their expected life cycle. The table indicates which structures will need to be monitored closely for future replacement.

7. Transformer Assets

Transformer Assets – Condition Assessment

Midland PUC has 707 pole mounted and 385 pad mounted transformers.

Existing records provided the year of manufacture for transformers (if it was originally recorded/available). In the event that a manufacture date was not available, the year of oldest adjacent transformer was assumed. An assumption was also made that the date of installation in 95% of the cases would correspond with the installation date of the pole or line section that it was installed on. Although we recognize the year of manufacture may not be the year of installation – we assumed that in over 90% of the cases that the year of manufacture is the same year or within a few months from the date of purchase that the equipment was put into service.

Asset depreciation based on age is a useful tool for predicting future need. However, many assets are operational for many years beyond the expected life. These assets should be routinely inspected and monitored to ensure they are suitable for ongoing service. Transformer loading also contributes to the asset condition and life cycle. The incorporation of smart meter information to determine peak, duration, load profile, etc. will aid with identifying the transformer assets at the highest risk of failure. This detailed information may also be used for potentially derating transformers to a lower KVA and transferring customers with the intent of extending the life cycle of aged transformer assets.

Table 10: Age Risk Rating Categories for Pole/Pad Mounted Transformers

Pole and Pad Mount Transformers	
Age - Risk Rating Category	Year Grouping
1	< 5 yrs
2	5-9 yrs
3	10-19 yrs
4	20-29 yrs
5	> 30 yrs

Table 11: Age Risk Rating Categories for Pole/Pad Mounted Transformers Quantities

Calculated Age Risk Rating Category	Quantity
1	112
2	105
3	140
4	573

5	162
Total	1092

Location:

In order to determine a location risk rating; we required further information that links customer information to transformers. The most current Customer Information System yielded this information. An analysis has been done to identify which transformers feed critical customers as well as identify the particular assets servicing larger commercial and industrial customers. This information also permits accurate transformer loading to be assigned to each transformer. Ensuring transformers are neither over-loaded nor under-loaded will increase the service life of these assets.

Pole Mounted Transformers

The inventory and visual condition assessment information for the entire pole mounted transformers in the Midland PUC distribution system is contained in Appendix B. This includes the data collected in the field and the existing attributes from Midland PUC's transformer asset registry. The age of the transformer was collected in the original records. This age value was utilized to assign the numerical age risk category for prioritizing which assets will likely need replacement and in which order. It also provides a listing of the transformers that may require more frequent inspections and/or testing. Detailed depreciation and utilization models will be able to be determined once the customer information is integrated with the transformers. Actual loading values will be available to assist with determining over-loaded or under-loaded transformers (both contributing factors to decreasing the life expectancy of a transformer). For the purposes of this study, we focused on the age and condition variables to assist us with prioritizing which overhead pole mounted transformers to repair and replace.

Pad Mounted Transformers

The inventory and visual condition assessment information for the entire pad mounted transformers in the Midland PUC distribution system is contained in Appendix B. This includes the data collected in the field and the existing attributes from Midland PUC's transformer asset registry. The age of the transformer was collected during the field inventory/inspection. This age value was utilized to assign the numerical age risk category for prioritizing which assets will likely need replacement and in which order. It also provides a listing of the transformers that may require more frequent inspections and/or testing. Detailed depreciation and utilization models will be able to be determined once the customer information is integrated with the transformers. Actual loading values will be available to assist with determining over-loaded or under-loaded transformers (both contributing factors to decreasing the life expectancy of a transformer).

There are some older secondary and service line sections that will require replacement in the coming years. At this point they are providing acceptable levels of service and unless a customer requests a service to be replaced there is no need for replacement at this point. These lines should be part of a regular inspection process and monitored closely for changes in condition.

8. Deterioration Models and Assumptions

The field inventory provided detailed condition information for all the assets. A visual inspection was completed for all overhead and visible underground assets. Each asset was categorized into the following categories/subcategories and the current age of each asset was compared to an industry standard expected life cycle.

Table 12: Asset Typical Useful Life Cycles

Category	Sub-Category	Typical Useful Life (yrs.)
Transmission		
	Poles/Towers/Fixtures	45
	Conductors	60
	Switching Devices	45
Substations / Metering Stations		
	Fencing	40
	Grounding Grid	40
	Reclosers / Switching Devices	40
	Power Transformers	45
	Switch Gears	50
	HV/LV Cables, Insulators, and Duct Banks	50
	Super structure – fuses, grounding, and lightning protection	40
Distribution		
	Poles/Towers/Fixtures	45
	Conductors (Overhead)	60
	Conductors (Underground)	40
	Switching Devices	45
	Transformers (Overhead - Pole Mounted)	40
	Transformers (Underground - Pad Mounted)	40
Secondary		
	Poles/Towers/Fixtures	45

	Conductors	60
	Metering Points	30

____
* Source: [11] Ontario Energy Board – Kinectrics Inc., "Asset Amortization Study for the Ontario Energy Board", July 8, 2010

Asset Replacement Assumptions:

Transmission:

- Equipment is replaced concurrently with structure replacements
- Conductors are replaced concurrently with structure replacements
- Pole framings, hardware, cross arms, anchors, and guying are replaced concurrently with structure replacements.

Substations/Metering Stations:

- All components of a station structure are replaced when replacing a given substation or metering station.
- Each device or piece of equipment may be replaced as needed independent of the replacement of the overall structure.

Distribution:

- Equipment is replaced concurrently with structure replacements
- Conductors are replaced concurrently with structure replacements
- Pole framings, hardware, cross arms, anchors, and guying are replaced concurrently with structure replacements.

9. Identified Projects Schedule

The schedule of projects from 2012-2016 is summarized below. This includes the Asset Management Plan projects identified for that year, and additional projects developed to maintain and advance the Asset Management Plan.

Table 13: Project Schedule

Project ID	Type	Title	2012	2013	2014	2015	2016
MPUC-IP-001	Capital	William St. North - Yonge St. to Gloucester St.					
MPUC-IP-002	Capital	Pratt's Field - Brandon DS to Dorion DS					
MPUC-IP-003	Capital	William St. South - Yonge St. to Bayview St.					
MPUC-IP-004	Capital	Fourth St. - Victoria St. to Bay St.					
MPUC-IP-005	Capital	Victoria St. - Eighth St. to Woodland					
MPUC-IP-060	Capital	Quebec St. - Fourth St. to Eighth St.					
MPUC-IP-007	Capital	Yonge St. - William to King St.					
MPUC-IP-008	Capital	Fourth St. - Bay St. to Hugel					
MPUC-IP-009	Capital	Queen St. - Bay St. to Gloucester St.					
MPUC-IP-010	Capital	M2-M4 Easement					
MPUC-IP-011	Capital	King St. - Yonge to Elizabeth					
MPUC-IP-012	Capital	King St. - Robert St. to Galloway Blvd.					
MPUC-AM-001	Annual Maintenance	Thermal/Infra-Red Imaging					
MPUC-AM-002	Annual Maintenance	Pole Mount Transformer - Maintenance/Repair					
MPUC-AM-003	Annual Maintenance	Pad Mount Transformer - Maintenance/Repair					
MPUC-AM-004	Annual Maintenance	Vegetation Clearing					
MPUC-AM-005	Annual Maintenance	Pole/Line Inspections					
MPUC-AM-006	Annual Maintenance	Pole Top Maintenance					
MPUC-AM-007	Annual Maintenance	Substation Oil Tests/Analysis/Inpsections					

Project ID	Type	Title	2012	2013	2014	2015	2016
MPUC-RM-001	Repairs/Maintenance	Broken Ground Wires					
MPUC-RM-002	Repairs/Maintenance	Broken Guy Wires					
MPUC-RM-003	Repairs/Maintenance	Broken Moldings					
MPUC-RM-004	Repairs/Maintenance	Guy Repairs (Loose, Guy Guard Missing,...)					

MPUC-CA-001	Capital	Pole Replacements - Immediate (Within One Year)					
MPUC-CA-002	Capital	Pole Replacements - Planned (Within Five Years)					
MPUC-CA-003	Capital	Transformer Replacements - Immediate (Within One Year)					
MPUC-CA-004	Capital	Transformer Replacements - Planned (Within Five Years)					

IP	**Identified Projects**
AM	**Annual Maintenance**
RM	**Repairs & Maintenance**
CA	**Condition Assessment**

10. Recommendations

In order to ensure that asset management information is current and supportive enough to make sound decisions, and executing the appropriate projects at the proper time and at the appropriate level of expenditure we recommend the following activities:

Inspections

Routine inspections will assist with providing the information necessary for making accurate asset management decisions. The inspection results will aid with determining future inspection schedules and maintenance planning. At a minimum, inspections should comply with the OEB's Distribution System Code. We also encourage the inclusion of scientific testing on high priority assets (those identified with a higher calculated weighted value). This testing will provide quantitative results as well as provide values available for future regulatory requirements (ie. non-linear design requirements). It is also beneficial to consult with scientific testing firms to review results from their previous projects to identify trends in asset degradation relative to age, manufacturer, maintenance, treatment, etc. This will aid with identifying additional assets that may be at risk within your asset base.

The inspection records should be integrated with the GIS. This will permit Midland PUC the ability to visualize all inspection details in a spatial context. It will also permit the cross-referencing of outages and/or other network issues with individual assets. The inspection results should be a primary input for decisions on maintenance efforts. An internal audit or review should be performed to ensure all asset information is complete.

Maintenance

On-going asset maintenance requires continuous effort and decisions regarding extent and frequency. Over a period of time, records management will indicate reliability benefits with respect to efforts expended on maintenance. In some cases, inspections and maintenance can be completed concurrently (i.e. pole testing and treatment as well as a complete pole line inspection).

It is recommended that Midland PUC have some defined process for cause/effect analysis in the event of an outage. The results of the cause/effect analysis could be cross-referenced in the GIS for other assets with similar characteristics to ensure inspections and maintenance is applied accordingly. The cause/effect analysis should incorporate standardized codes that are in compliance with those codes determined by the OEB.

It is also recommended that maintenance standards be defined in a document, providing specific detail regarding procedures for each maintenance activity. This will ensure consistency for each time an activity is performed. Maintenance records should be linked to the GIS and readily available for cross-referencing with an outage or other incident records.

Information Management

It is our recommendation that the GIS be continuously used as the central repository for maintaining an asset inventory. Additional information systems that track and monitor inspections, maintenance, capital planning, and financing can all easily be integrated with the GIS. This provides a common base of asset data and a portal for visualizing information from all inter-related sources.

Key considerations with respect to information management are:

- Asset data should be easily accessible by all engineering and operations personnel.
- The GIS system should be integrated with other information management systems (inspections, maintenance, capital projects, and outages.)
- Paper-based processes are to be eliminated to a reasonable extent, with all information systems integrated (avoiding duplication of data entry and ensuring everyone has the most current data available for decision making).
- Management should have regular access to integrated information and reports regarding asset management activities and outcomes.

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11. Ontario Energy Board – Kinectrics Inc., "Asset Amortization Study for the Ontario Energy Board", July 8, 2010

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CAPITALIZATION POLICY

Midland PUC has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. Going forward capitalization will conform to the Modified International Financial Reporting Standards (MIFRS). The information found in this section applies to capitalization under CGAAP only. Changes due to the implementation of MIFRS are described in Tab 5 – Conversion to MIFRS.

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

GUIDELINES FOR CAPITALIZATION

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and is therefore capitalized. A "betterment" includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Amortization

Capital assets are amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry. A full years amortization is calculated on a straight line basis over estimated useful life of the asset. For the purposes of this rate application, Midland PUC used the half year rule for calculating depreciation expense for the 2013 Test Year. Details of Midland PUC's depreciation by account number are provided in the Fixed Asset Continuity Schedules as set out in Exhibit 2, Tab 2, Schedule 4.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

SERVICE QUALITY & RELIABILITY PERFORMANCE

Midland PUC tracks service reliability statistics SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) including and excluding loss of supply related incidents. However, reliability statistics excluding loss of supply have only been recorded since 2010. The following shows results for the past three years.

Table 2.3.13 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2009	3.07	0.85	3.62
2010	4.88	1.14	4.29
2011	3.68	1.74	2.11
Excluding Loss of Supply			
2009	n/a	n/a	n/a
2010	3.71	0.73	5.09
2011	2.24	1.02	2.19

Midland PUC is committed to the reliability of the distribution system. Table 2.4.2 below summarizes the 2012 and 2013 target indices for SAIDI and SAIFI.

Table 2.3.14 - Target Indices for 2012 and 2013

Year	SAIDI	SAIFI	CAIDI
Including Loss of Supply			
2012	2.84	1.51	1.88
2013	2.84	1.51	1.88
Excluding Loss of Supply			
2012	2.05	1.47	1.39
2013	2.05	1.47	1.39

In order to meet these targets Midland PUC will need to continue to invest in capital and maintenance programs. In particular, the capital programs previously noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets removes the risk to reliability and safety that would otherwise be unacceptable.

In addition to the reliability indices, Midland PUC also measures service quality indicators (“SQIs”). Table 2.4.3 below summarizes Midland PUC’s reported SQIs for the historical years 2009, 2010 and 2011. In 2010, the SQI’s were replaced by the Electricity Service Quality Requirements (ESQRs).

1 **Table 2.3.15 - Reported Service Quality Indicators (SQIs)**

Indicator	OEB Minimum Standard	2009	2010	2011
Connection fo New Services - Low Voltage	90% within 5 days	100%	94%	100%
Connection of New Services - High Voltage	90% within 10 days	N/A	N/A	N/A
Telephone Call Accessibility Rate	65% of calls answered within 30 seconds	100%	100%	100%
Appointments Scheduled	90% of the time	N/A	100%	86%
Appointments Met	90% of the time	100%	100%	100%
Written Responses to Inquiries	80% within 10 days	91%	96%	100%
Emergency Response - Urban Areas	80% within 60 minutes	100%	100%	100%
Emergency Response - Rural Areas	80% within 120 minutes	N/A	N/A	N/A

ALLOWANCE FOR WORKING CAPITAL:

In accordance with the Ontario Energy Board's letter dated April 12, 2012 "*RE: Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications – Allowance for Working Capital*", Midland PUC has incorporated the default value of 13% as the Allowance Approach for Working Capital on the following basis:

> The 13% Allowance Approach is calculated to be 13% of the sum of Cost of Power and controllable expenses (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).
>
> The commodity price estimate used to calculate the Cost of Power is based on the split between RPP and non-RPP customers on actual data. The calculation reflects the most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. In the event new Uniform Transmission Rates are approved by the Board before finalization of this Rate Application, the commodity price estimate will be recalculated to reflect those new rates.

Overview and Calculation by Account:

Midland PUC's working capital allowance is forecast to be $ 2,906,528 for 2013 under MIFRS based on the methodology outlined above in accordance with the April 12, 2012 letter from the Ontario Energy Board. Table 2.4.1 sets out Midland PUC's working capital allowance calculation.

Table 2.4.1: Working Capital Allowance Calculation 2013 (MIFRS)

WORKING CAPITAL ALLOWANCE FOR 2013

Distribution Expenses		
Distribution Expenses - Operation		378,987
Distribution Expenses - Maintenance		548,841
Billing and Collecting		498,599
Community Relations		4,450
Administrative and General Expenses		1,085,056
Taxes Other than Income Taxes		30,385
Total Eligible Distribution Expenses		**2,546,318**
Power Supply Expenses		19,811,587
Total Working Capital Expenses		22,357,905
Working Capital Allowance @	13.00%	2,906,528

As indicated in Exhibit 2, Schedule 1, Table 2.1.1(b) provides a summary of Working Capital comparison for the 2009 OEB Approved, 2009, 2010 and 2011 Actual years and 2012 Bridge Year/2013 Test Year under both CGAAP and MIFRS. No changes to the working capital calculations result from the conversion to MIFRS from CGAAP. This Table is reproduced here for reference to Table 2.4.1 above.

Table 2.1.1(b): Summary of Working Capital 2009-2013

Description	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (CGAAP)	2013 Test (MIFRS)
Cost of Power	$ 17,781,953	$ 16,591,122	$ 18,173,779	$ 18,857,557	$ 20,427,576	$ 20,427,576	$ 19,811,587	$ 19,811,587
Operations	$ 455,700	$ 325,787	$ 191,621	$ 228,798	$ 349,599	$ 349,599	$ 378,987	$ 378,987
Maintenance	$ 353,900	$ 337,863	$ 436,383	$ 440,148	$ 457,389	$ 457,389	$ 548,841	$ 548,841
Billing & Collecting	$ 435,800	$ 434,238	$ 414,278	$ 239,980	$ 479,686	$ 479,686	$ 498,599	$ 498,599
Community Relations	$ 5,600	$ 1,316	$ 3,900	$ 3,728	$ 3,527	$ 3,527	$ 4,450	$ 4,450
Administration & General Expense	$ 814,150	$ 689,371	$ 801,674	$ 879,150	$ 930,199	$ 930,199	$ 1,085,056	$ 1,085,056
Property Taxes	$ 34,200	$ 31,052	$ 30,058	$ 28,676	$ 29,500	$ 29,500	$ 30,385	$ 30,385
Working Capital	$ 19,881,303	$ 18,410,749	$ 20,051,694	$ 20,678,037	$ 22,677,476	$ 22,677,476	$ 22,357,905	$ 22,357,905

COST OF POWER

Midland PUC has calculated cost of power for the 2012 Bridge Year and 2013 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Report – May 1, 2012 to April 30, 2013, issued April 2, 2012. Midland PUC will update the electricity prices should the OEB publish a revised Regulated Price Plan Report prior to a Decision.

The Cost of Power calculations for the 2012 Bridge Year and a cost of power summary are provided in the following Table 2.4.2 and Table 2.4.3 respectively. The cost of power calculations for the 2013 Test Year and a cost of power summary are provided in the following Table 2.4.4 and Table 2.4.5 respectively. No changes to the Cost of Power calculations are made as a result of the transition to MIFRS.

Table 2.4.2 Cost of Power Forecast Calculation – 2012 Bridge Year

2012 Load Foreacst	kWh	kW	2011 %RPP
Residential	48,361,864		85%
General Service < 50 kW	23,264,544		87%
General Service 50 to 4,999 kW	125,556,253	313,327	6%
Street Lighting	1,357,947	3,713	0%
Sentinel Lighting	0	-	0%
Unmetered Scattered Load	432,346		98%
TOTAL	**198,972,953**	**317,040**	

Electricity - Commodity RPP	2012 Forecasted	2012 Loss			
Class per Load Forecast RPP	**Metered kWhs**	**Factor**	**2012**		
Residential	40,998,881	1.0651	43,667,908	$0.08069	$3,523,564
General Service < 50 kW	20,224,004	1.0651	21,540,587	$0.08069	$1,738,110
General Service 50 to 4,999 kW	8,028,740	1.0651	8,551,411	$0.08069	$690,013
Street Lighting	0	1.0651	0	$0.08069	$0
Sentinel Lighting	0	1.0651	0	$0.08069	$0
Unmetered Scattered Load	424,313	1.0651	451,936	$0.08069	$36,467
TOTAL	**69,675,938**		**74,211,842**		**$5,988,154**

Table 2.4.2 Cost of Power Forecast Calculation – 2012 Bridge Year (con’d)

Electricity - Commodity Non-RPP Class per Load Forecast	2012 Forecasted Metered kWhs	2012 Loss Factor	2012		
Residential	7,362,983	1.0651	7,842,313	$0.07877	$617,739
General Service < 50 kW	3,040,539	1.0651	3,238,478	$0.07877	$255,095
General Service 50 to 4,999 kW	117,527,513	1.0651	125,178,554	$0.07877	$9,860,315
Street Lighting	1,357,947	1.0651	1,446,349	$0.07877	$113,929
Sentinel Lighting	0	1.0651	0	$0.07877	$0
Unmetered Scattered Load	8,033	1.0651	8,556	$0.07877	$674
TOTAL	**129,297,015**		**137,714,251**		**$10,847,752**

Transmission - Network Class per Load Forecast		Volume Metric	2012		
Residential		kWh	51,510,221	$0.0057	$293,608
General Service < 50 kW		kW	24,779,065	$0.0052	$128,851
General Service 50 to 4,999 kW		kW	313,327	$2.1368	$669,517
Street Lighting		kWh	3,713	$1.6116	$5,984
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	460,492	$0.0052	$2,395
TOTAL					**$1,100,356**

Transmission - Connection Class per Load Forecast		Volume Metric	2012		
Residential		kWh	51,510,221	$0.0047	$242,098
General Service < 50 kW		kW	24,779,065	$0.0043	$106,550
General Service 50 to 4,999 kW		kW	313,327	$1.6983	$532,123
Street Lighting		kWh	3,713	$1.3129	$4,875
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	460,492	$0.0043	$1,980
TOTAL					**$887,627**

Wholesale Market Service Class per Load Forecast			2012		
Residential			51,510,221	$0.0052	$267,853
General Service < 50 kW			24,779,065	$0.0052	$128,851
General Service 50 to 4,999 kW			133,729,965	$0.0052	$695,396
Street Lighting			1,446,349	$0.0052	$7,521
Sentinel Lighting			0	$0.0052	$0
Unmetered Scattered Load			460,492	$0.0052	$2,395
TOTAL			**211,926,093**		**$1,102,016**

Rural Rate Assistance Class per Load Forecast			2012		
Residential			51,510,221	$0.0011	$56,661
General Service < 50 kW			24,779,065	$0.0011	$27,257
General Service 50 to 4,999 kW			133,729,965	$0.0011	$147,103
Street Lighting			1,446,349	$0.0011	$1,591
Sentinel Lighting			0	$0.0011	$0
Unmetered Scattered Load			460,492	$0.0011	$507
TOTAL			**211,926,093**		**$233,119**

Low Voltage Class per Load Forecast			2012		
Residential			51,510,221	$0.0015	$77,265
General Service < 50 kW			24,779,065	$0.0013	$32,213
General Service 50 to 4,999 kW			313,327	$0.5012	$157,040
Street Lighting			3,713	$0.3873	$1,438
Sentinel Lighting			0	$0.3864	$0
Unmetered Scattered Load			460,492	$0.0013	$599
TOTAL			**77,066,819**		**268,554**

Table 2.4.3 Cost of Power Summary – 2012 Bridge Year

	2012
4705-Power Purchased	$16,835,905
4708-Charges-WMS	$1,102,016
4714-Charges-NW	$1,100,356
4716-Charges-CN	$887,627
4730-Rural Rate Assistance	$233,119
4750-Low Voltage	$268,554
TOTAL	**20,427,576**

Table 2.4.4 Cost of Power Forecast Calculation – 2013 Test Year

2013 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	49,023,071		85%
General Service < 50 kW	23,098,239		87%
General Service 50 to 4,999 kW	117,836,449	287,241	6%
Street Lighting	1,314,588	3,595	0%
Sentinel Lighting	0	-	0%
Unmetered Scattered Load	412,397		98%
TOTAL	**191,684,743**	**290,836**	

Electricity - Commodity RPP	**2013 Forecasted**	**2013 Loss**			
Class per Load Forecast RPP	**Metered kWhs**	**Factor**	**2013**		
Residential	41,559,420	1.0682	44,395,776	$0.08069	$3,582,295
General Service < 50 kW	20,079,435	1.0682	21,449,820	$0.08069	$1,730,786
General Service 50 to 4,999 kW	7,535,094	1.0682	8,049,351	$0.08069	$649,502
Street Lighting	0	1.0682	0	$0.08069	$0
Sentinel Lighting	0	1.0682	0	$0.08069	$0
Unmetered Scattered Load	404,734	1.0682	432,357	$0.08069	$34,887
TOTAL	**69,578,683**		**74,327,304**		**$5,997,470**

Electricity - Commodity Non-RPP	**2013 Forecasted**	**2013 Loss**			
Class per Load Forecast	**Metered kWhs**	**Factor**	**2013**		
Residential	7,463,650	1.0682	7,973,031	$0.07877	$628,036
General Service < 50 kW	3,018,804	1.0682	3,224,832	$0.07877	$254,020
General Service 50 to 4,999 kW	110,301,355	1.0682	117,829,225	$0.07877	$9,281,408
Street Lighting	1,314,588	1.0682	1,404,306	$0.07877	$110,617
Sentinel Lighting	0	1.0682	0	$0.07877	$0
Unmetered Scattered Load	7,663	1.0682	8,186	$0.07877	$645
TOTAL	**122,106,060**		**130,439,579**		**$10,274,726**

Table 2.4.4 Cost of Power Forecast Calculation – 2013 Test Year (con'd)

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	52,368,807	$0.0055	$287,068
General Service < 50 kW		kW	24,674,652	$0.0050	$123,393
General Service 50 to 4,999 kW		kW	287,241	$2.0550	$590,267
Street Lighting		kWh	3,595	$1.5499	$5,571
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	440,542	$0.0050	$2,203
TOTAL					**$1,008,504**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	52,368,807	$0.0045	$237,043
General Service < 50 kW		kW	24,674,652	$0.0041	$102,183
General Service 50 to 4,999 kW		kW	287,241	$1.6356	$469,806
Street Lighting		kWh	3,595	$1.2644	$4,545
Sentinel Lighting		kW	0	$0.0000	$0
Unmetered Scattered Load		kW	440,542	$0.0041	$1,824
TOTAL					**$815,402**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential			52,368,807	$0.0052	$272,318
General Service < 50 kW			24,674,652	$0.0052	$128,308
General Service 50 to 4,999 kW			125,878,576	$0.0052	$654,569
Street Lighting			1,404,306	$0.0052	$7,302
Sentinel Lighting			0	$0.0052	$0
Unmetered Scattered Load			440,542	$0.0052	$2,291
TOTAL			**204,766,883**		**$1,064,788**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential			52,368,807	$0.0011	$57,606
General Service < 50 kW			24,674,652	$0.0011	$27,142
General Service 50 to 4,999 kW			125,878,576	$0.0011	$138,466
Street Lighting			1,404,306	$0.0011	$1,545
Sentinel Lighting			0	$0.0011	$0
Unmetered Scattered Load			440,542	$0.0011	$485
TOTAL			**204,766,883**		**$225,244**

Low Voltage					
Class per Load Forecast				**2013**	
Residential			52,368,807	$0.0021	$108,193
General Service < 50 kW			24,674,652	$0.0018	$44,180
General Service 50 to 4,999 kW			287,241	$0.6903	$198,286
Street Lighting			3,595	$0.5334	$1,918
Sentinel Lighting			0	$0.5322	$0
Unmetered Scattered Load			440,542	$0.0018	$789
TOTAL			**77,774,838**		**353,366**

Smart Meter Entity					
Class per Load Forecast		**# Customers**		**2013**	
Residential		6,231		$0.8600	$64,301
General Service < 50 kW		755		$0.8600	$7,787
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					**72,088**

Table 2.4.5 Cost of Power Summary – 2012 Bridge Year

	2013
4705-Power Purchased	$16,272,196
4708-Charges-WMS	$1,064,788
4714-Charges-NW	$1,008,504
4716-Charges-CN	$815,402
4730-Rural Rate Assistance	$225,244
4750-Low Voltage	$353,366
4708 - Smart Meter Entity	$72,088
TOTAL	**19,811,587**

Conversion to Modified International Financial Reporting Standards (MIFRS)

Overview:

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that will have Canadian GAAP (CGAAP) transitioned to International Financial Reporting Standards (IFRS), effective January 1, 2013 and which will require entities to restate, for comparative purposes, their 2012 interim and annual financial statements and their opening 2013 financial position.

In October 2010, the AcSB approved the incorporation of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2011. The AcSB has proposed that qualifying entities with rate regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook for an additional two years. This amendment also requires entities that do not prepare their interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

Midland PUC deferred implementation of IFRS to January 1, 2013.

Transitional Analysis and Findings:

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective: To document Midland PUC's accounting policy on componentization and depreciation of property, plant and equipment.

Background: Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item, shall be depreciated separately.

Using the Kinetrics Inc. Asset Amortization Study dated April 28, 2010, Report K-418022-RA-0001-R003, prepared for the Ontario Energy Board, Midland PUC has adopted the Typical Useful Life (TUL) for fixed assets in accordance with this study, except for some of the distribution station assets and overhead conductors. Details of these exceptions are provided below. With respect to all other useful lives, Midland PUC does not have better data upon which to determine the TUL and experience has shown that the TUL in the report is closer to the actual useful lives being experienced, than under CGAAP.

Depreciation is to be calculated on the basis of the estimated useful life of the item after deducting its residual value when fully depreciated. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors.

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and in the condition necessary for it to be capable of operating in the manner as intended). Depreciation of an asset ceases, at the earlier of the date that the asset is classified as held for Sale, in accordance with IFRS 5, and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted for under IFRS. Each significant Component, and their estimated useful lives, for purposes of computing depreciation expense under IFRS, will be tracked in a sub account.

Table 2.5.1 below, provides details of the conclusions from this transition and provides a comparison of PP&E's useful life as it was assigned under CGAAP and the revised TUL under MIFRS.

Table 2.5.1: Schedule of PP&E Useful Life Assets

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	5-10

Midland PUC has adopted the Kinectric's Report Typical Useful Life (TUL) in all asset categories, with the following exceptions which deal with the componentization of distribution substation assets:

Steel Structure:

As indicated in the Kinetrics Report at Appendix H, Section 23, "Steel Structure is considered to be a part of the Transformer and Municipal Stations asset grouping". Four of Midland PUC's distribution stations are housed in steel clad buildings. The Kinetrics Report provides for a TUL for "steel structure" of 50 years. These substations contain steel structures, however, when replacing the transformers and switchgear Midland PUC's plan would be to replace the steel structure at the same time. Consequently, Midland PUC has aligned the steel structure life with the life of the substation assets, being 40 years.

Two of our stations, Montreal and Queen are brick structures. Midland PUC has determined the administrative building highest Typical Useful Life of 75 years is the appropriate TUL for these assets.

Other Distribution Station Equipment:

Other distribution station equipment has been amortized over 30 years based on an average useful life of the other distribution station components. Each component is, not by itself, considered a significant component of the station and an average useful life was determined by weighing the cost of each component against total value of the "other distribution station equipment" based on the Kinetrics Report Typical Useful Life.

As discussed previously, Midland PUC retained BDO Dunwoody, LLP to provide assistance in the transition of financial records from CGAAP to IFRS which included the assignment of useful lives to the asset base.

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2013.

The 2012 Rate Base has been restated as part of this Rate Application, in MIFRS format as required by the Addendum to the Report of the Board (EB-2008-0408) issued June 13, 2011 on Implementing IFRS, Appendix A, Issue 2.

Standard: IAS 16 – Property, Plant and Equipment:

Topic: Capitalization - Overheads

Objective: To document the accounting policy on the capitalization of overheads.

Core Principle: The cost of an item of PP&E is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and;
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training);
d) Administration and other general overhead costs; and
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Midland PUC's Observations and Conclusions:

Under IFRS the following costs will be capitalized:

Directly Attributable:

The cost must be directly attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

Payroll Burden:

Payroll allocation consists of the following benefits paid to or for employees: health benefits, WSIB, and the company portion of OMERS, CPP and EI. IAS 16 specifically allows for benefits as defined in IAS 19 to be included as a directly attributable cost. The payroll burden is allocated to capital based upon payroll dollars charged to capital.

Rolling Stock (Vehicle Burden):

The vehicle burden is allocated to capital based on the time that the vehicle is used on the job site, thus establishing the fact that the use of the vehicle is directly attributable to an item of PP&E.

Under IFRS the following costs will **not** be Capitalized:

- General and administrative overhead
- Day-to-day servicing costs - Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose

of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E.

- Under IFRS, training costs cannot be capitalized, but training on how to use a piece of equipment can be capitalized.

Amortization expense is an estimate of the deterioration of the vehicle. Amortization is not included as an overhead and therefore is left as an administration expense.

Conclusion:

Midland PUC has determined there are a few minor changes required to our processes under MIFRS going forward, but any impact will be negligible as our Capitalization process to date was IFRS compliant.

For Depreciation, Midland PUC will need to track costs in sub accounts for componentization, because of different Typical Useful Life (TUL) periods and resulting differing depreciation rates.

Impact on Fixed Assets

Midland PUC has elected to take the IFRS 1 Exemption for rate regulated entities, which allows the use of the net book value of assets as at the date of transition as the deemed cost of the asset. This change has been reflected in the continuity statements provided in Exhibit 2, Tab 2, Schedule 1 which are reproduced below for the 2012 Bridge Year (Table 2.2.4(b)) and the 2013 Test Year (Table 2.2.5(b)). The opening balance of the gross fixed assets for the 2012 Bridge year is the net book value of the assets for the same date under CGAAP.

The OEB commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to IFRS (EB-2008-0408) the Board stated: "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that generic depreciation study could assist with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the services life for their particular assets for financial reporting and regulatory requirements."

Midland PUC has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). Midland PUC has used the mid-range typical useful life for its assets, except for the items described above (as illustrated in Table 2.5.1 above) as described in the Kinetrics Study. Consequently, the useful lives have been extended causing net depreciation (depreciation expense to the income statement) to be reduced in the 2013 Test Year. This change has been reflected in the Continuity Statements provided below for the 2012 Bridge Year and 2013 Test Year as shown in the tables on the following pages.

Table 2.2.4(b): Asset Continuity Schedule 2012 Bridge Year (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,041,733	$ 563,200	-$ 192,651	$ 5,412,282	$ 1,334,736	$ 139,209	-$ 134,498	$ 1,339,447	$ 4,072,835
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,583,735	$ 323,600	-$ 114,540	$ 4,792,795	$ 2,276,158	$ 70,682	-$ 101,673	$ 2,245,167	$ 2,547,628
47	1835	Overhead Conductors & Devices		$ 2,197,671	$ 91,160	-$ 52,043	$ 2,236,788	$ 1,121,197	$ 24,472	-$ 51,162	$ 1,094,508	$ 1,142,280
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,330,392	$ 16,021	$ -	$ 1,346,413	$ 602,528
47	1845	Underground Conductors & Devices		$ 1,380,324	$ 392,500	$ -	$ 1,772,824	$ 837,834	$ 30,372	$ -	$ 868,206	$ 904,618
47	1850	Line Transformers		$ 3,423,353	$ 303,600	-$ 54,870	$ 3,672,084	$ 1,970,928	$ 55,449	-$ 51,201	$ 1,975,176	$ 1,696,908
47	1855	Services (Overhead & Underground)		$ 304,423	$ 33,900	$ -	$ 338,323	$ 25,029	$ 5,015	$ -	$ 30,044	$ 308,279
47	1860	Meters		$ 1,104,459	$ 13,000	$ -	$ 1,117,459	$ 703,094	$ 35,988	$ -	$ 739,082	$ 378,376
47	1860	Meters (Smart Meters)		$ -	$ 1,204,471	$ -	$ 1,204,471	$ 172,164	$ 75,774	$ -	$ 247,938	$ 956,533
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,025,772	$ 45,000	$ -	$ 1,070,772	$ 444,415	$ 16,792	$ -	$ 461,208	$ 609,564
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 226,029	$ 5,379	$ -	$ 231,408	$ 28,616
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 464,983	$ 29,500	$ -	$ 494,483	$ 419,275	$ 19,649	$ -	$ 438,924	$ 55,559
45	1920	Computer Equip.-Hardware(Smart Meters)		$ -	$ 18,764	$ -	$ 18,764	$ 7,379	$ 3,753	$ -	$ 11,132	$ 7,632
52	1925	Software		$ 363,056	$ 10,200	$ -	$ 373,256	$ 292,447	$ 32,289	$ -	$ 324,735	$ 48,521
12	1925	Software (Smart Meters)		$ -	$ 68,016	$ -	$ 68,016	$ 21,832	$ 13,603	$ -	$ 35,435	$ 32,581
10	1930	Transportation Equipment - Large Vehicles		$ 858,183	$ 525,400	-$ 372,388	$ 1,011,195	$ 482,962	$ 93,562	-$ 297,556	$ 278,968	$ 732,227
	1930	Transportation Equipment - Small Vehicles		$ 161,023	$ 10,800	$ -	$ 171,823	$ 122,196	$ 9,601	$ -	$ 131,797	$ 40,027
8	1935	Stores Equipment		$ 8,610	$ -	$ -	$ 8,610	$ 8,610	$ -	$ -	$ 8,610	-$ 0
8	1940	Tools, Shop & Garage Equipment		$ 272,825	$ 16,900	$ -	$ 289,725	$ 207,890	$ 11,616	$ -	$ 219,506	$ 70,218
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,031	$ 300	$ -	$ 132,331	$ 1,779
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,778	$ 177	$ -	$ 18,955	$ 265
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ -	$ -	$ 562,328	$ 298,397	$ 16,047	$ -	$ 314,444	$ 247,883
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 1,621,821	-$ 594,100	$ 49,724	-$ 2,166,197	$ -	-$ 49,724	$ 49,724	$ -	-$ 2,166,197
	etc.						$ -				$ -	$ -
		Total		**$ 22,909,879**	**$ 3,055,911**	**-$ 736,768**	**$ 25,229,022**	**$ 12,471,467**	**$ 626,027**	**-$ 586,366**	**$ 12,511,128**	**$ 12,717,894**

Table 2.2.5(b): Asset Continuity Schedule 2013 Test Year (MIFRS)

				Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Depreciation Rate	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)		$ 32,555	$ -	$ -	$ 32,555	$ 15,060	$ -	$ -	$ 15,060	$ 17,495
N/A	1805	Land		$ 381,738	$ -	$ -	$ 381,738	$ -	$ -	$ -	$ -	$ 381,738
47	1806	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 5,412,282	$ 896,700	-$ 121,867	$ 6,187,115	$ 1,339,447	$ 155,584	-$ 120,043	$ 1,374,988	$ 4,812,127
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 4,792,795	$ 353,100	-$ 141,554	$ 5,004,341	$ 2,245,167	$ 76,808	-$ 125,881	$ 2,196,094	$ 2,808,247
47	1835	Overhead Conductors & Devices		$ 2,236,788	$ 99,700	-$ 28,571	$ 2,307,917	$ 1,094,508	$ 26,099	-$ 25,363	$ 1,095,244	$ 1,212,673
47	1840	Underground Conduit		$ 1,948,941	$ -	$ -	$ 1,948,941	$ 1,346,413	$ 16,021	$ -	$ 1,362,434	$ 586,507
47	1845	Underground Conductors & Devices		$ 1,772,824	$ 387,500	$ -	$ 2,160,324	$ 868,206	$ 40,122	$ -	$ 908,329	$ 1,251,995
47	1850	Line Transformers		$ 3,672,084	$ 318,900	-$ 42,010	$ 3,948,974	$ 1,975,176	$ 62,659	-$ 39,772	$ 1,998,063	$ 1,950,911
47	1855	Services (Overhead & Underground)		$ 338,323	$ 30,900	$ -	$ 369,223	$ 30,044	$ 5,676	$ -	$ 35,719	$ 333,503
47	1860	Meters		$ 1,117,459	$ 10,000	-$ 801,102	$ 326,357	$ 739,082	$ 33,914	-$ 543,986	$ 229,011	$ 97,346
47	1860	Meters (Smart Meters)		$ 1,204,471	$ -	$ -	$ 1,204,471	$ 247,938	$ 75,774	$ -	$ 323,712	$ 880,759
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	1908	Buildings & Fixtures		$ 1,070,772	$ 25,000	$ -	$ 1,095,772	$ 461,208	$ 16,550	$ -	$ 477,758	$ 618,015
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ 260,024	$ -	$ -	$ 260,024	$ 231,408	$ 4,357	$ -	$ 235,765	$ 24,259
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	1920	Computer Equipment - Hardware		$ 494,483	$ 22,200	$ -	$ 516,683	$ 438,924	$ 22,367	$ -	$ 461,291	$ 55,392
45	1920	Computer Equip.-Hardware(Smart Meters)		$ 18,764	$ -	$ -	$ 18,764	$ 11,132	$ 3,753	$ -	$ 14,885	$ 3,879
52	1925	Software		$ 373,256	$ 55,000	$ -	$ 428,256	$ 324,735	$ 23,911	$ -	$ 348,647	$ 79,610
12	1925	Software (Smart Meters)		$ 68,016	$ -	$ -	$ 68,016	$ 35,435	$ 13,603	$ -	$ 49,038	$ 18,978
10	1930	Transportation Equipment - Large Vehicles		$ 1,011,195	$ -	$ -	$ 1,011,195	$ 278,968	$ 126,399	$ -	$ 405,368	$ 605,828
	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 & Garage Equipment		$ 289,725	$ 10,000	$ -	$ 299,725	$ 219,506	$ 12,961	$ -	$ 232,467	$ 67,257
8	1945	Measurement & Testing Equipment		$ 2,634	$ -	$ -	$ 2,634	$ 2,634	$ -	$ -	$ 2,634	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ 134,110	$ -	$ -	$ 134,110	$ 132,331	$ 300	$ -	$ 132,631	$ 1,479
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ 19,220	$ -	$ -	$ 19,220	$ 18,955	$ 177	$ -	$ 19,132	$ 88
47	1975	Load Management Controls Utility Premises		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
12	1980	System Supervisor Equipment		$ 562,328	$ 175,000	$ -	$ 737,328	$ 314,444	$ 20,422	$ -	$ 334,867	$ 402,461
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 2,166,197	-$ 588,100	$ 64,211	-$ 2,690,085	$ -	-$ 64,211	$ 64,211	$ -	-$ 2,690,085
	etc.										$ -	$ -
		Total		**$ 25,229,022**	**$ 1,795,900**	**-$ 1,070,893**	**$ 25,954,029**	**$ 12,511,128**	**$ 682,735**	**-$ 790,834**	**$ 12,403,029**	**$ 13,551,000**

Impact on Capital Budgets

Componentization and Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition, IAS 16 requires entities perform a review of its useful lives, amortization methods and residual values on an annual basis.

Midland PUC has reviewed the useful life of its assets with the aid of the Kinetrics report. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets. Midland PUC has changed the useful life of its assets to the "Typical Useful Life" TUL as defined in the Kinetrics study, except for those distribution station items listed above. Midland PUC has restated its continuity statements for the 2012 Bridge Year and the 2013 Test Year to include these changes.

Table 2.5.1, Schedule of PP&E Useful Life Assets summarizes the useful life period being adopted from 2012 by Midland PUC compared to the mid-point rate as recommended by the Kinectrics study.

PP&E Deferral Account and Request for Disposition:

The conversion from Canadian Generally Accepted Accounting Principles (CGAAP) to Modified International Financial Reporting Standards (MIFRS) has resulted in some changes to Midland PUC's accounting for Plant Property and Equipment (PP&E).

Table 2.5.2 IFRS-CGAAP Transitional PP&E Amounts below illustrates Midland PUC's forecast of the PP&E Deferral account as a result of transition from CGAAP to Modified IFRS, with Modified IFRS incorporating the revised componentized Typical Useful Life as previously stated in Table 2.5.1

Table 2.5.2 IFRS-CGAAP Transitional PP&E Amounts

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$	$	$	$	$
PP&E Values under CGAAP								
Opening net PP&E - Note 1				10,438,412				
Additions less Disposals				2,768,722				
Depreciation (amounts should be negative)				-724,705				
Closing net PP&E (1)				12,482,429				
PP&E Values under MIFRS (Starts from 2012, the transition year)								
Opening net PP&E - Note 1				10,438,412				
Additions less Disposals				2,319,143				
Depreciation (amounts should be negative)				-39,661				
Closing net PP&E (2)				12,717,894				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)				-235,465				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance				0	-235465	-176599	-117733	-58866
Amounts added in the year				-235465				
Sub-total				-235465	-235465	-176599	-117733	-58866
Amount of amortization, included in depreciation expense - Note 2					58866	58866	58866	58866
Closing balance in deferral account				-235465	-176599	-117733	-58866	0

Effect on Revenue Requirement			
Amortization of deferred balance as above - Note 2	-58866	**WACC**	5.66%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	-13323	**Disposition Period - Note 4**	4 Years
Amount included in Revenue Requirement on rebasing	-72189		

Table 2.5.2 above illustrates that through the transition from CGAPP to MIFRS, with MIFRS incorporating the revised componentized Useful Life as previously stated, the calculated difference in closing net PP&E for 2013 Test Year is reduced by $ -235465. As Midland PUC transfers from CGAAP to Modified IFRS from January 1, 2013, it is anticipated that this variance will need to recorded and tracked in the Deferral / Variance account which has been identified as a request to the OEB in Exhibit 9.

Based on the *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2009-0408) dated June 13, 2012, Midland PUC requests this amount be moved to a PPE deferral account for disposition to customers. Midland PUC requests a four year disposition period. As directed, this amount will not attract carrying charges but will attract the same level of return as used in determining revenue requirement for this cost of service application as shown on Table 2.5.2.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition.

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. Midland PUC will continue to use the Cost Model to measure PP&E.

MIFRS Impact on Rate Base

Table 2.5.3 below provides a comparison of rate base between CGAAP and MIFRS for the 2013 Test Year. The change in Net Book Value has been described above. The working capital allowance has not increased as there are no changes to OM&A expenses under MIFRS.

Table 2.5.3 – Impact of MIFRS – Rate Base

	2012 Bridge Year - CGAAP	2013 Test Year - CGAAP	2012 Bridge Year - MIFRS	2013 Test Year - MIFRS	Variance
Gross Fixed Assets	25,678,601	26,770,364	25,229,022	25,954,029	
Accumulated Depreciation	13,196,172	13,750,169	12,511,128	12,403,029	
Net Book Value	12,482,429	13,020,195	12,717,894	13,551,000	
Average Net Book Value	11,460,420	12,751,312	11,578,153	13,134,447	
Working Capital Allowance	3,401,621	2,906,528	3,401,621	2,906,528	
Rate Base	14,862,042	15,657,839	14,979,774	16,040,975	383,135

Table 2.5.4 provides details of the impact of MIFRS on the revenue requirement for the 2013 Test Year which results in an overall variance of -$ 397,873 . This variance is made up of a reduction in amortization, and increase in the regulated return on capital and a reduction in PILs. In addition revenue offsets have decreased as a result of capital disposal recognition and one-fourth of the PP&E deferral account balance and associated rate of return.

Table 2.5.4 – Impact of MIFRS on Revenue Requirement

	2013 Test Year - CGAAP	2013 Test Year - MIFRS	Variance
OM&A	2,546,318	2,546,318	-
Amortization	1,001,018	682,735	- 318,283
Amortization on PP&E Adjustment		- 58,866	- 58,866
Return on PP&E Adjustment		- 13,323	- 13,323
Regulated Return on Capital	885,925	907,603	21,678
PILs	52,653	978	- 51,675
Service Revenue Requirement	4,485,914	4,065,446	- 420,469
Less: Revenue Offsets	286,200	263,604	- 22,596
Base Revenue Requirement	**4,199,714**	**3,801,842**	**- 397,873**

Tables 2.5.5 and 2.5.6 below provide details of the revenue deficiency for the 2013 Test Year under CGAAP and MIFRS.

Table 2.5.5 – Revenue Deficiency (CGAAP)

Description	2012 Bridge Actual	2013 Test Existing Rates	2013 Test - Required Revenue
Revenue			
Revenue Deficiency			**626,085**
Distribution Revenue	3,643,891	3,573,629	3,573,629
Other Operating Revenue (Net)	305,555	286,200	286,200
Total Revenue	**3,949,446**	**3,859,829**	**4,485,914**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,413,412	1,588,105	1,588,105
Operation & Maintenance	806,988	927,828	927,828
Depreciation & Amortization	937,061	1,001,018	1,001,018
Property Taxes	29,500	30,385	30,385
Deemed Interest	394,082	314,727	314,727
Total Costs and Expenses	**3,581,043**	**3,862,064**	**3,862,064**
Utility Income Before Income Taxes	**368,403**	**(2,235)**	**623,851**
Income Taxes:			
Corporate Income Taxes	5,696	(44,391)	52,653
Total Income Taxes	**5,696**	**(44,391)**	**52,653**
Utility Net Income	**362,708**	**42,156**	**571,198**
Income Tax Expense Calculation:			
Accounting Income	368,403	(2,235)	623,851
Tax Adjustments to Accounting Income	(331,657)	(284,156)	(284,156)
Taxable Income	**36,746**	**(286,390)**	**339,695**
Income Tax Expense	5,696	(44,391)	52,653
Tax Rate Refecting Tax Credits	15.50%	15.50%	15.50%
Actual Return on Rate Base:			
Rate Base	14,862,042	15,657,839	15,657,839
Interest Expense	394,082	314,727	314,727
Net Income	362,708	42,156	571,198
Total Actual Return on Rate Base	**756,789**	**356,883**	**885,925**
Actual Return on Rate Base	5.09%	2.28%	5.66%
Required Return on Rate Base:			
Rate Base	14,862,042	15,657,839	15,657,839
Return Rates:			
Return on Debt (Weighted)	4.42%	3.35%	3.35%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	394,082	314,727	314,727
Return On Equity	476,180	571,198	571,198
Total Return	**870,262**	**885,925**	**885,925**
Expected Return on Rate Base	5.86%	5.66%	5.66%
Revenue Deficiency After Tax	**113,472**	**529,042**	**(0)**
Revenue Deficiency Before Tax	**134,287**	**626,085**	**(0)**

Tax Exhibit	**2013**
Deemed Utility Income	571,198
Tax Adjustments to Accounting Income	(284,156)
Taxable Income prior to adjusting revenue to PILs	**287,042**
Tax Rate	15.50%
Total PILs before gross up	**44,492**
Grossed up PILs	**52,653**

Table 2.5.6 – Revenue Deficiency (MIFRS)

Description	2012 Bridge Actual (MIFRS)	2013 Test (MIFRS) Existing Rates	2013 Test (MIFRS) - Required Revenue
Revenue			
Revenue Deficiency			**228,213**
Distribution Revenue	3,643,891	3,573,629	3,573,629
Other Operating Revenue (Net)	229,986	263,604	263,604
Total Revenue	**3,873,877**	**3,837,233**	**4,065,446**
Costs and Expenses			
Administrative & General, Billing & Collecting	1,413,412	1,588,105	1,588,105
Operation & Maintenance	806,988	927,828	927,828
Depreciation & Amortization	626,027	682,735	682,735
Amortization on PP&E Adjustment		(58,866)	(58,866)
Return on PP&E Adjustment		(13,323)	(13,323)
Property Taxes	29,500	30,385	30,385
Deemed Interest	397,204	322,428	322,428
Total Costs and Expenses	**3,273,131**	**3,479,293**	**3,479,293**
Utility Income Before Income Taxes	**600,746**	**357,940**	**586,153**
Income Taxes:			
Corporate Income Taxes	5,212	(34,395)	978
Total Income Taxes	**5,212**	**(34,395)**	**978**
Utility Net Income	**595,535**	**392,335**	**585,175**
Income Tax Expense Calculation:			
Accounting Income	600,746	357,940	586,153
Tax Adjustments to Accounting Income	(567,122)	(579,843)	(579,843)
Taxable Income	**33,625**	**(221,903)**	**6,310**
Income Tax Expense	5,212	(34,395)	978
Tax Rate Refecting Tax Credits	15.5000%	15.5000%	15.50%
Actual Return on Rate Base:			
Rate Base	14,979,774	16,040,975	16,040,975
Interest Expense	397,204	322,428	322,428
Net Income	595,535	392,335	585,175
Total Actual Return on Rate Base	**992,738**	**714,763**	**907,603**
Actual Return on Rate Base	6.63%	4.46%	5.66%
Required Return on Rate Base:			
Rate Base	14,979,774	16,040,975	16,040,975
Return Rates:			
Return on Debt (Weighted)	4.42%	3.35%	3.35%
Return on Equity	8.01%	9.12%	9.12%
Deemed Interest Expense	397,204	322,428	322,428
Return On Equity	479,952	585,175	585,175
Total Return	**877,156**	**907,603**	**907,603**
Expected Return on Rate Base	5.86%	5.66%	5.66%
Revenue Deficiency After Tax	**(115,583)**	**192,840**	**0**
Revenue Deficiency Before Tax	**(136,784)**	**228,213**	**0**

Tax Exhibit	**2013**
Deemed Utility Income	585,175
Tax Adjustments to Accounting Income	(579,843)
xable Income prior to adjusting revenue to PILs	**5,332**
Tax Rate	15.50%
Total PILs before gross up	**826**
Grossed up PILs	**978**

GREEN ENERGY PLAN

Midland PUC has submitted a basic Green Energy Plan to the OPA and has provided a copy in Appendix C. The OPA provided a Letter of Comment which has been provided in Appendix D. As part of its plan Midland PUC has forecasted no capital spending requirements which would affect the rate base calculations in this Application.

APPENDIX C

GREEN ENERGY PLAN

BASIC GREEN ENERGY PLAN, April 17, 2012

1. Introduction:

This document outlines the Green Energy Act Plan for the Midland Power Utility Corporation (Midland PUC).

At this time Midland PUC is filing a basic Green Energy Plan, rather than a detailed plan, as provided for in OEB documentation EB-2009-0397. This basic GEA Plan provides information to the Board and interested stakeholders regarding the readiness of Midland PUC's system to accommodate the connection of renewable generation and the expansion or reinforcement necessary to accommodate renewable generation. In addition this report provides information with respect to the general condition of the distribution system.

Midland PUC is an urban electric distribution company servicing the Town of Midland with a total service area of 20 sq km, a municipal population of approximately 17,000 and a summer peaking load and a customer base of approximately 7,000 electric customers. The distribution plant presently consists of a sub-transmission network at 44kV, municipal sub-stations at 8.3KV and 4.16kV. Midland PUC is in the process of upgrading a 4.16 KV sub-station. This station is the second last to be upgraded to new arc-proof design in accordance with a Substation Study completed in 2006 and updated in 2011.

All current and proposed renewable generation for Midland PUC distribution service area is primarily composed of solar (PV) rooftop mounted installations. To date, the total planned and proposed renewable generation in Midland PUC's distribution service area is approximately 38kW for Micro-FIT and 750kW for FIT.

Midland PUC is committed to providing reliable service with an infrastructure which meets current and future needs. This Green Energy Plan is but one of the planning and reporting initiatives undertaken to maintain an effective distribution system. Other planning initiatives include the Substation, Load and Asset Management Studies.

2. Current Assessment of Distribution System

2.1. Distribution System Overview:

- Midland PUC is an urban electric distribution company servicing the Town of Midland with a total service area of 20 sq km, a municipal population of approximately 17,000 and a summer peaking load and a customer base of approximately 7,000 electric customers
- Midland PUC has a strong industrial customer base, balanced with commercial and residential loads.
- The Town of Midland has experienced little growth over the past 20 years

- Midland PUC is supplied through 44 KV sub-transmission and one 8.32 KV sub-station and six 4.16 KV sub-stations.
- Midland PUC is aggressively upgrading pole lines, insulators, and conductor to improve reliability and sustainability of the overhead distribution system. This also improves power factor and reduces voltage losses. Four of the six 4.16 KV sub-stations have been upgraded with new switchgear complete with SCADA relays.

Table 1 - System Summary Overview	
System Peak (kW - Date)	37,873.9 kW Jul 20/11
Service Area (sq. km)	20 sq km
Total Customers	6972
GS>50	135
GS<50	747
Residential	6090
PME's	3
Poles	1846
Distribution Stations	6
Primary Lines (km)	
44kV – OH 3 phase (km circuit)	23
8.32kV - OH 3 Phase (km circuit)	12.9
8.32kV - OH 1 Phase (km circuit)	4.9
8.32kV - UG 3 Phase (km circuit)	1.8
8.32kV - UG 1 Phase (km circuit)	.8
4.16kV - OH 3 Phase (km circuit)	46.9
4.16kV – OH 1 Phase (km circuit)	13.8
4.16kV – UG 3 Phase (km circuit)	15.2
4.16kV – UG 1 Phase (km circuit)	21.3
Transformers	
OH	707
UG	385

2.2. Embedded Distribution System

Midland PUC's distribution system is embedded in the Hydro One system.

Midland PUC is fed from two dedicated 44 KV feeders the 98-M2 and 98-M4 and two feeders shared with Hydro One and Power Stream the 98-M3 and 98-M7. There is a 500 KW solar PV array currently connected to the 98-M4 and a 250 KW solar PV array scheduled to connect in 2012 on the 98-M2. The 98-M3 is express to Midland however there is some solar arrays connected down stream of Midland PUC's load on this feeder. The 98-M7 is also express to Midland with some solar arrays downstream of Midland PUC's load on this feeder.

2.3. Municipal Substations

Midland PUC has six Municipal substations serving the community. The total connected capacity is 42.5 Mva as at July, 2011 providing a margin of safety over the peak system load of 60%. The sub-transmission system (44kV) allows for transfer of loads between stations as required.

2.3.1. No. 1 DORION

- Name of station: Dorion
- Age: 2010
- Capacity and transformer configuration: 5 MVA
- Number of feeders: 3
- Type of protection: relay / breaker
- 1 spare breaker

2.3.2. No. 2 MONTREAL

- Name of station: Montreal
- Age: 1968, Transformer age is 1990
- Capacity and transformer configuration: 10 MVA
- Number of feeders: 5
- Type of protection: relay / breaker

2.3.3. No. 3 BRANDON

- Name of station: Brandon
- Age: 2008
- Capacity and transformer configuration: 7.5 MVA
- Number of feeders: 3
- Type of protection: relay / breaker
- 1 spare breaker

2.3.4. No. 4 QUEEN

- Name of station: Queen
- Age: 1949, Transformer age is 1986
- Capacity and transformer configuration: 5 MVA
- Number of feeders : 4
- Type of protection: relay / breaker

2.3.5. No. 5 SCOTT

- Name of station: Scott
- Age: 2007, Transformer age is 2004
- Capacity and transformer configuration: 5 MVA
- Number of feeders : 4
- Type of protection: relay / breaker

2.3.6. No. 6 FOURTH

- Name of station: Fourth
- Age: 2009
- Capacity and transformer configuration: 5 MVA
- Number of feeders : 3
- Type of protection : relay / breaker
- 1 spare feeder

2.3.7. No. 7 FIRTH

- Name of station: Firth
- Capacity and transformer configuration: 5 MVA
- Number of feeders : 3
- Type of protection : Oil Re-closure
- Owned by Hydro One

2.4. Station Metering and Monitoring

Midland PUC has four sub-stations with a total of 13 feeders that have full SCADA ready relays. The current plan is that the remaining stations will be upgraded one in 2012 and the other in 2013. This will allow Midland PUC to monitor all 4.16 KV feeders in the Town of Midland.

2.5. Feeder Capacities to Connect Generation

Midland PUC has set parameters for setting capacity for connected generation. Each feeder loading was averaged and the parameter was set at 25% of these averages. This was determined by taking the capacity set by Hydro One for our dedicated feeders and spreading those limits across the distribution feeders. This allowed Midland PUC to set parameters for each municipal sub-station feeder.

Table 2 - Feeder Summary

Station	Feeder	Average Load 2011	Available Capacity	FIT Applications	MicroFIT Applications	Remaining Capacity
Brandon	Feeder 1	470 kW	118 kW	-	-	118 kW
Brandon	Feeder 2	453 kW	113 kW	-	-	113 kW
Brandon	Feeder 3	179 kW	45 kW	-	-	45kW
Dorion	Feeder 1	82 kW	341 kW	-	-	341 kW
Dorion	Feeder 2	63 kW	262 kW	-	-	262 kW
Dorion	Feeder 3	45 kW	187 kW	-	-	187 kW
Fourth	Feeder 2	208 kW	52 kW	-	-	52 kW
Fourth	Feeder 3	262 kW	66 kW	-	-	66 kW
Fourth	Feeder 4	624 kW	156 kW	-	-	156 kW
Montreal	Feeder 1	416 kW	104 kW	-	1 = 10kW	94 kW
Montreal	Feeder 2	374 kW	94 kW	-	-	94 kW
Montreal	Feeder 3	362 kW	90 kW	-	-	90 kW
Montreal	Feeder 4	707 kW	177 kW	-	1 =4.5 kW	172 kW
Queen	Feeder 1	728 kW	182 kW	-	-	182 kW
Queen	Feeder 2	458 kW	114 kW	-	-	114 kW
Queen	Feeder 3	391 kW	98 kW	-	-	98 kW
Queen	Feeder 4	508 kW	127 kW	-	-	127 kW
Scott	Feeder 1	408 kW	102 kW	-	1=9.1kW	92.9 kW
Scott	Feeder 2	241 kW	60 kW	-	1=9.9kW	50 kW
Scott	Feeder 3	358 kW	89 kW	-	1=4.18 kW	84 kW
Scott	Feeder 4	150 kW	37 kW	-	-	37 kW
Waub	98-M4	3300 kW	825 kW	1 = 500 kW	-	325 kW
Waub	98-M2	4600 kW	1150 kW	1 = 250 kW	-	900 kW

2.6. Identification of Expenditures:

Midland PUC has experienced very little interest in Fit and Micro FIT installations therefore capital or OM&A expenditures are not required over the next five years to accommodate the forecasted Renewable Generation. Further expansion coupled with an increase of normal loads will also increase limits allowing for more renewable generation in the future.

2.7. Unique Challenges:

Midland PUC serves an urban customer base load made up of residential, small to medium commercial and industrial customers.

The majority of connected and proposed green energy connections in the Town of Midland are made up of rooftop FIT and micro-FIT projects. FIT projects will typically be installed by commercial and industrial customers with a large rooftop footprint. Large renewable generation FIT applications received or expected with five years (100kW – 500kW) will typically displace customer load at the host site and are not expected to be net-exporters of energy to the distribution system. The interest in FIT and micro-FIT projects has been slow at best; it does not appear Midland PUC will reach capacity of Generation in the foreseeable future.

3. Planned Development of the Distribution System to Accommodate Generation Connections

3.1. Existing and Pending Renewable Generation Projects:

Midland PUC's generator connection application process requires the involvement of Hydro One. The application process includes internal review of applications by technical services, metering and distribution departments. Midland PUC also requires approval from Hydro One for connection capacity as Hydro One is the Host distributor. Midland PUC continues to meet with interested parties but few applications have resulted from these enquiries. The total expected connection over the next 5 years is not deemed to be significant. Hydro One is planning to connect two large FIT projects up-stream from Midland PUC although total size and connection location information is not available to Midland PUC at this time. This could greatly reduce the capacities for Midland PUC. Any FIT applications will be planned through Hydro One, who must approve the installations.

3.2. Infrastructure Projects and Activities to Accommodate Renewable Generation

Midland PUC continues to upgrade existing infrastructure to improve the reliability and longevity of the distribution system. With limited FIT and micro-FIT systems planned over the next 5 years, projects for the sole purpose to accommodate renewable Generation will not be required.

4. Smart Grid Development:

This section is not required in a basic GEA Plan.

5. Summary: *(Concluding comments)*

The GEA Plan has been prepared to illustrate the ability to accommodate renewable generation. Through the plan the existing capacity has been outlined as well as requirements for future investments.

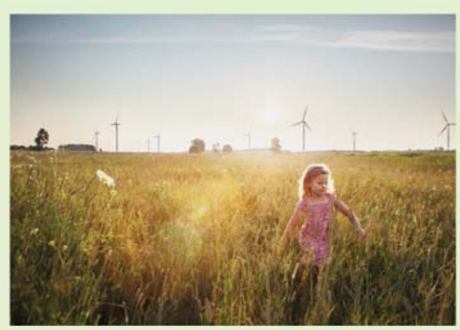
APPENDIX D

OPA LETTER OF COMMENT

OPA Letter of Comment:

Midland Power Utility Corporation

Basic Green Energy Act Plan



June 5, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Midland Power Utility Corporation - Basic Green Energy Act Plan

On May 10, 2012 the OPA reviewed the Basic GEA Plan of Midland Power Utility Corporation ("Midland Power") dated April 17, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

Section 1 of Midland Power's GEA Plan indicates that there are 38 kW of microFIT and 750 kW of FIT projects that are planned and proposed to be connected in Midland Power's distribution system.

According to the OPA's information, as of May 16, 2012, there are 5 connected microFIT projects, totalling 40 kW of capacity, and 26 microFIT projects totalling 170 kW of capacity, that have applied to connect to Midland Power's distribution system.

According to applications that the OPA has received as of May 16, 2012, 2 FIT applications that have received contracts, totalling 750 kW of capacity in Midland Power's distribution service territory. In addition, OPA has received 4 FIT applications representing approximately 700 kW of capacity in Midland Power's territory prior to the FIT Program Review.

Upstream Transmission Constraints

According to the information provided in Midland Power's GEA Plan, Midland Power receives its supply from Waubaushene TS. The OPA notes that there are no currently known upstream transmission constraints at Waubaushene TS.

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info@powerauthority.on.ca www.powerauthority.on.ca

Further details on capacity at the Waubaushene TS, may be found in the updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

The OPA is not aware of any opportunities for integrated solutions among neighbouring LDCs at this time.

Conclusion

The OPA finds that Midland Power's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Midland Power's Basic GEA Plan.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 1-800-797-9604 Toll Free
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OVERVIEW OF OPERATING REVENUE:

This Exhibit provides the details of Midland PUC's operating revenue for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Under MIFRS Midland PUC is proposing a total Service Revenue Requirement of $ 4,065,446 for the 2013 Test Year. This amount includes a Base Revenue Requirement of $ 3,801,842 plus revenue offsets of $ 263,604 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented in Table 3.1.1 and provides a comparison of total revenues from the 2009 OEB approved year to the 2013 Test Year (MIFRS).

Throughput Revenue:

Information related to Midland PUC's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results and a forecast of customers by rate class based on the historical number of customers billed throughout the year.

A detailed variance analysis on this historical throughput revenue is also provided in this exhibit.

Overall load reductions from 2009 to the 2013 forecast amounts can be attributed to three major factors - seasonal weather conditions, economic downturn in the manufacturing sector and the success of conservation initiatives. As illustrated in Table 3.2.23 Summary of Forecast of this exhibit, average consumption per customer has steadily declined in each rate class, except for streetlighting.

Information related to Midland PUC's throughput revenue includes details such as weather normalized forecasting methodology, normalized volume based on historical number of customers billed throughout the year and CDM adjustments and known economic conditions.

A detailed variance analysis on the throughput revenue is set out in Exhibit 3, Tab 3 Schedule 1.

Other Revenue:

Other revenues include Standard Service Supply (SSS) Administration Charges, Late Payment Charges, Miscellaneous Service Revenues and Rental Revenues.

A detailed variance analysis on other revenue is set out in Exhibit 3, Tab 3, and Schedule 2.

Table 3.1.1: Summary of Operating Revenue

Operating Revenue	2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2012 Bridge (MIFRS)	2013 Test (MIFRS)
Distribution Revenue							
Residential	$ 1,846,829	$ 1,793,665	$ 1,813,778	$ 1,816,939	$ 2,053,180	$ 2,053,180	$ 2,046,360
GS<50kW	$ 529,784	$ 485,508	$ 523,485	$ 486,941	$ 549,308	$ 549,308	$ 584,548
GS>50kW	$ 922,838	$ 766,705	$ 911,364	$ 980,025	$ 885,752	$ 885,752	$ 1,036,446
Streetlights	$ 68,195	$ 48,881	$ 99,086	$ 118,099	$ 121,089	$ 121,089	$ 128,464
Unmetered Scattered Load	$ 17,473	$ 13,708	$ 16,113	$ 17,084	$ 15,063	$ 15,063	$ 6,023
Sentinel Lights	$ 5,259	$ 156					
MicroFit	$ -						
Total	$ 3,390,378	$ 3,108,622	$ 3,363,825	$ 3,419,088	$ 3,624,391	$ 3,624,391	$ 3,801,842
% of Total Revenue	*93.6%*	*89.2%*	*91.1%*	*91.0%*	*91.8%*	*93.6%*	*93.5%*
Other Distribution Revenue							
SSS Administration Revenue	$ 15,825	$ 16,935	$ 17,355	$ 17,883	$ 19,500	$ 19,500	$ 19,500
Rent from Electric Property	$ 82,481	$ 90,166	$ 82,895	$ 80,638	$ 77,300	$ 77,300	$ 78,200
Other Electric Revenues	$ -	$ 1,363	$ 835	$ 5,664	$ 5,600	$ 5,600	$ 5,600
Late Payment Charges	$ 10,000	$ 20,871	$ 19,795	$ 22,518	$ 23,400	$ 23,400	$ 23,400
Regulatory Credits		$ -	$ -	$ -	$ -	$ -	$ -
Specific Service Charges	$ 91,625	$ 105,670	$ 108,002	$ 121,897	$ 122,100	$ 122,100	$ 108,600
Rev From Merchandising, Jobbing	$ 82,000	$ 34,900	$ 85,867	$ 78,046	$ 92,500	$ 92,500	$ 94,300
Costs and Exp Merchandising, Jobbing	-$ 60,800	-$ 18,636	-$ 63,870	-$ 54,180	-$ 63,000	-$ 63,000	-$ 64,500
Gain from Retirement of Utility and Other	$ -	$ 13,025	$ -	$ -	$ 26,855	$ 26,855	$ -
Loss from Retirement of Utility and Other	$ -	$ -	-$ 2,543	-$ 2,433	$ -	-$ 75,569	-$ 22,596
Rev from Non-Utility Operations	$ -	$ 303,650	$ 225,318	$ 60,591	$ 57,600	$ 57,600	$ 58,800
Expenses from Non-Utility Op'n	$ -	-$ 229,702	-$ 177,889	-$ 42,125	-$ 36,800	-$ 36,800	-$ 37,700
Interest & Dividend Income	$ 10,000	$ 37,483	$ 33,635	$ 51,417	$ -	$ -	$ -
Total	$ 231,131	$ 375,725	$ 329,399	$ 339,917	$ 325,055	$ 249,486	$ 263,604
% of Total Revenue	6.4%	10.8%	8.9%	9.0%	8.2%	6.4%	6.5%
Grand Total	$ 3,621,509	$ 3,484,347	$ 3,693,225	$ 3,759,004	$ 3,949,446	$ 3,873,877	$ 4,065,446

THROUGHPUT REVENUE

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by Midland PUC to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, Midland PUC has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, Midland PUC submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. Midland PUC has the data for the amount of electricity (in kWh) purchased from the IESO and Hydro One for use by Midland PUC's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to bill kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, Intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. Midland PUC attempted to conduct the regression analysis on an individual rate class basis. Midland PUC estimated the amount consumed in a month by rate class using an equation to prorate billing that was used in the process for unbilled revenue. However, based on the R square and Adjusted R square values shown in the following Table 3.2.1, Midland PUC concluded using the equation resulting from the individual rate class regression analysis would not provide a prediction formula that was as good as the prediction equation from the power purchased method. The R square and Adjusted R square values for the power purchased method are 90% and 89%, respectively. In addition, the total 2013 kWh forecast would be slightly lower using the individual rate class prediction formula.

Table 3.2.1: R Square and Adjusted R Square Values for Individual Class Regression Analysis		
Class	**R Square**	**Adjusted R Square**
Residential	86%	85%
GS<50	71%	69%
GS>50	71%	70%

During the review of 2010 cost of service applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant as the number of customers increased as the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and Intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. Midland PUC has attempted to address these concerns in the load forecast used in this Application. Based on the OEB's approval of this methodology in a number of previous cost of service applications and based on the discussion that follows, Midland PUC submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by Midland PUC in this Application.

The information in the table below provides weather actual data from 2003 to 2011, while 2012 and 2013 are weather normalized. Midland PUC does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and streetlight, sentinel lights and unmetered loads are measured as connections.

Table 3.2.2: Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2009 Board Approved	218.6			8,448		
2003 Actual	224.2			7,734		
2004 Actual	227.2	3.0	1.3%	7,872	138.0	1.8%
2005 Actual	233.2	6.0	2.7%	8,013	141.0	1.8%
2006 Actual	225.7	(7.6)	(3.2%)	8,090	77.0	1.0%
2007 Actual	221.4	(4.2)	(1.9%)	8,224	134.0	1.7%
2008 Actual	211.2	(10.3)	(4.6%)	8,284	60.0	0.7%
2009 Actual	205.1	(6.0)	(2.9%)	8,419	135.0	1.6%
2010 Actual	205.7	0.6	0.3%	8,832	413.0	4.9%
2011 Actual	200.6	(5.1)	(2.5%)	8,861	29.0	0.3%
2012 Bridge	**199.0**	**(1.7)**	**(0.8%)**	**9,019**	**158.2**	**1.8%**
2013 Test	**191.7**	**(7.3)**	**(3.7%)**	**9,182**	**162.4**	**1.8%**

Actual and forecasted billed amounts and numbers of customers are shown in Table 3.2.3 and customer usage is shown in Table 3.2.4, on a rate class basis.

Table 3.2.3: Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Billed Energy (GWh)							
2009 Board Approved	49.8	27.7	139.4	1.2	0.0	0.5	218.6
2003 Actual	46.6	27.0	148.9	1.7	0.0	0.0	224.2
2004 Actual	46.6	26.8	152.5	1.3	0.1	0.0	227.2
2005 Actual	48.4	26.8	157.0	1.1	0.0	0.0	233.2
2006 Actual	46.7	26.1	151.7	1.1	0.0	0.0	225.7
2007 Actual	47.9	26.9	145.0	1.1	0.0	0.5	221.4
2008 Actual	48.3	25.8	135.3	1.2	0.0	0.5	211.2
2009 Actual	48.1	25.4	130.0	1.2	0.0	0.5	205.1
2010 Actual	48.1	25.1	130.7	1.4	0.0	0.5	205.7
2011 Actual	47.6	23.4	127.8	1.4	0.0	0.5	200.6
2012 Bridge	**48.4**	**23.3**	**125.6**	**1.4**	**0.0**	**0.4**	**199.0**
2013 Test	**49.0**	**23.1**	**117.8**	**1.3**	**0.0**	**0.4**	**191.7**
Number of Customers/Connections							
2009 Board Approved	6,018	729	103	1,564	22	12	8,448
2003 Actual	5,531	689	114	1,384	16	0	7,734
2004 Actual	5,533	718	114	1,469	38	0	7,872
2005 Actual	5,661	715	114	1,487	36	0	8,013
2006 Actual	5,727	709	106	1,523	25	0	8,090
2007 Actual	5,828	730	107	1,525	22	12	8,224
2008 Actual	5,896	719	110	1,525	22	12	8,284
2009 Actual	6,031	720	111	1,525	20	12	8,419
2010 Actual	6,053	740	112	1,915	0	12	8,832
2011 Actual	6,084	741	113	1,911	0	12	8,861
2012 Bridge	**6,157**	**748**	**113**	**1,990**	**0**	**12**	**9,019**
2013 Test	**6,231**	**755**	**113**	**2,072**	**0**	**12**	**9,182**

Table 3.2.4: Annual Usage per Customer/Connection by Rate Class

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL
Energy Usage per Customer/Connection (kWh per customer/connection)						
2009 Board Approved	8,274	37,930	1,353,671	765	725	42,796
2003 Actual	8,430	39,240	1,305,757	1,221	2,186	
2004 Actual	8,423	37,310	1,337,781	854	1,406	
2005 Actual	8,544	37,438	1,376,828	740	1,194	
2006 Actual	8,160	36,791	1,431,180	734	1,020	
2007 Actual	8,227	36,808	1,355,269	703	750	43,979
2008 Actual	8,196	35,895	1,230,337	773	705	43,254
2009 Actual	7,971	35,219	1,171,157	767	0	44,083
2010 Actual	7,945	33,892	1,167,316	715		38,556
2011 Actual	7,826	31,558	1,130,809	734		37,759
2012 Bridge	**7,855**	**31,112**	**1,112,342**	**683**		**36,029**
2013 Test	**7,868**	**30,610**	**1,045,100**	**635**		**34,366**
Annual Growth Rate in Usage per Customer/Connection						
2009 Board App. Vs. 2009 Actual	3.8%	7.7%	15.6%	(0.3%)		(2.9%)
2003 Actual						
2004 Actual	(0.1%)	(4.9%)	2.5%	(30.1%)	(35.7%)	
2005 Actual	1.4%	0.3%	2.9%	(13.4%)	(15.1%)	
2006 Actual	(4.5%)	(1.7%)	3.9%	(0.9%)	(14.6%)	
2007 Actual	0.8%	0.0%	(5.3%)	(4.1%)	(26.5%)	
2008 Actual	(0.4%)	(2.5%)	(9.2%)	9.9%	(6.0%)	(1.6%)
2009 Actual	(2.7%)	(1.9%)	(4.8%)	(0.7%)		1.9%
2010 Actual	(0.3%)	(3.8%)	(0.3%)	(6.7%)		(12.5%)
2011 Actual	(1.5%)	(6.9%)	(3.1%)	2.6%		(2.1%)
2012 Bridge	0.4%	(1.4%)	(1.6%)	(7.0%)		(4.6%)
2013 Test	0.2%	(1.6%)	(6.0%)	(7.0%)		(4.6%)

LOAD FORECAST AND METHODOLOGY

Midland PUC's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month, number of peak hours and CDM activity. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); days in month, CDM activity and number of peak hours. The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 108 monthly data points which represent a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, Midland PUC submits it is appropriate to review the impact of weather over the period January 2003 to December 2011 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, Midland PUC has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by Midland PUC to predict weather normal purchases for 2012 and 2013:

Midland PUC's Monthly Predicted kWh Purchases

= Heating Degree Days * 5,403
+ Cooling Degree Days * 19,682
+ Number of Days in the Month * 301,264
+ CDM Activity * (7.5)
+ Number of Peak Hours * 12,022
+ Intercept of 4,655,458

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from Pearson International Airport was used.

b) The calendar provided information related to number of days in the month and number of peak hours

c) The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for Midland PUC. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include preliminary actual results from 2011 programs that contribute to the four year licensed CDM kWh targets of 10,820,000 assigned to Midland PUC. The 2011 preliminary actual results are based on the fourth quarter 2011 CDM Status Report provided to Midland PUC by the OPA. The 2011 preliminary actual results have been included in the CDM activity variable since these results have impacted the actual 2011 power purchases. The following table outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the preliminary actual result from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 3,620,116 kWh which includes 2,535,176 kWh from the OPA final results plus 1,084,940 kWh reflecting the persistence of 2011 programs into 2013.

Table 3.2.5: 2011 Preliminary Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact				
Midland Power 4 Year 2011 to 2014 target				
10,820,000				
2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
1,032,669	1,084,940	1,084,940	1,084,940	4,287,487
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
437,952	765,816	1,191,886	2,539,169	
2010	2011	2012	2013	
2,887,748	2,590,841	2,554,143	2,535,176	

The increased saving in kWh from 2011 to 2012 from 2011 programs reflects a full year savings from an ERIP program that was not completed in 2011 until the end of April.

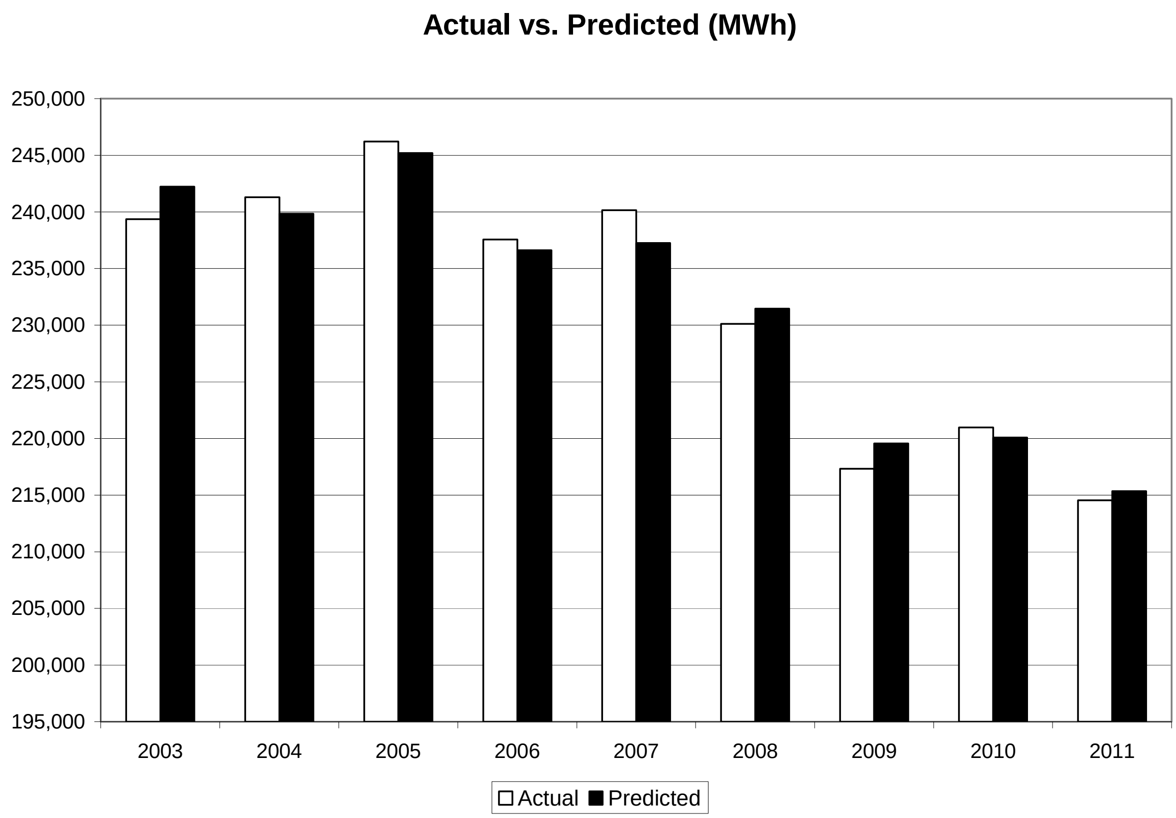
The impact of 2012 and 2013 CDM programs has not been included in the CDM activity variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2012 and 2013 programs and how LRAM variance account values are determined by rate class is provided later on in this schedule.

The prediction formula has the following statistical results:

Table 3.2.6: Statistcial Results

Statistic	Value
R Square	90%
Adjusted R Square	89%
F Test	180.2
T-stats by Coefficient	
Intercept	2.5
Heating Degree Days	22.1
Cooling Degree Days	15.1
Number of Days in Month	4.8
CDM Activity	(17.9)
Number of Peak Hours	4.0

The annual results of the above prediction formula compared to the actual annual purchases from 2003 to 2011 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for Midland PUC are provided for 2012 and 2013. For 2012 and 2013 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided with a 10 year average and a 20 year trend assumption for weather normalization.

Table 3.2.7: Total System Purchases			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2003	239.3	242.2	1.2%
2004	241.3	239.8	(0.6%)
2005	246.2	245.2	(0.4%)
2006	237.6	236.6	(0.4%)
2007	240.2	237.3	(1.2%)
2008	230.1	231.5	0.6%
2009	217.3	219.5	1.0%
2010	221.0	220.1	(0.4%)
2011	214.6	215.3	0.4%
2012 Weather Normal		**214.4**	
2013 Weather Normal		**214.3**	
2013 Weather Normal - 10 year average		**214.5**	
2013 Weather Normal - 20 year trend		**215.0**	

The weather normalized amount for 2013 is determined by using 2013 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2011 (i.e. nine years). The 2013 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2002 to December 2011. The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal nine year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The nine year average has been used as this is consistent with the period of time over which the regression analysis was conducted

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by Midland PUC using the average loss factor from 2003 to 2011 of 1.0683. With this average loss factor the total weather normalized billed energy will be 200.7 GWh for 2012 (i.e. 214.4/1.0683) and 200.6 GWh for 2013 (i.e. 214.3/1.0683) before adjustments for loss of load in the GS > 50 kW class as well as 2012 and 2013 CDM programs.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table 3.2.8: Historical Customer/Connection Data

Year	Residential	GS<50	GS>50	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections							
2003	5,531	689	114	1,384	16	0	7,734
2004	5,533	718	114	1,469	38	0	7,872
2005	5,661	715	114	1,487	36	0	8,013
2006	5,727	709	106	1,523	25	0	8,090
2007	5,828	730	107	1,525	22	12	8,224
2008	5,896	719	110	1,525	22	12	8,284
2009	6,031	720	111	1,525	20	12	8,419
2010	6,053	740	112	1,915	0	12	8,832
2011	6,084	741	113	1,911	0	12	8,861

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2003 to 2011.

Table 3.2.9: Growth Rate in Customer/Connections						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**Sentinels**	**USL**
Growth Rate in Customers/Connections						
2003						
2004	0.0%	4.2%	0.0%	6.1%	137.5%	
2005	2.3%	(0.4%)	0.0%	1.2%	(5.3%)	
2006	1.2%	(0.8%)	(7.0%)	2.4%	(30.6%)	
2007	1.8%	3.0%	0.9%	0.1%	(12.0%)	
2008	1.2%	(1.5%)	2.8%	0.0%	0.0%	0.0%
2009	2.3%	0.1%	0.9%	0.0%	(9.1%)	0.0%
2010	0.4%	2.8%	0.9%	25.6%		0.0%
2011	0.5%	0.1%	0.9%	(0.2%)		0.0%
Geometric Mean	**1.2%**	**0.9%**	**(0.1%)**	**4.1%**		**0.0%**

The resulting geometric mean was first applied to the 2011 customer/connection numbers to determine the forecast of customer/connections in 2012 and 2013. The following table outlines the forecast of customers and connections by rate class.

Table 3.2.10: Customer/Connection Forecast						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**	**Total**
Forecast Number of Customers/Connections						
2012	**6,157**	**748**	**113**	**1,990**	**12**	**9,019**
2013	**6,231**	**755**	**113**	**2,072**	**12**	**9,182**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2011.

Table 3.2.11: Historical Annual Usage per Customer					
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**
Annual kWh Usage Per Customer/Connection					
2003	8,430	39,240	1,305,757	1,221	0
2004	8,423	37,310	1,337,781	854	0
2005	8,544	37,438	1,376,828	740	0
2006	8,160	36,791	1,431,180	734	0
2007	8,227	36,808	1,355,269	703	43,979
2008	8,196	35,895	1,230,337	773	43,254
2009	7,971	35,219	1,171,157	767	44,083
2010	7,945	33,892	1,167,316	715	38,556
2011	7,826	31,558	1,130,809	734	37,759

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table 3.2.12: Growth Rate in Usage Per Customer/Connection					
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**
Growth Rate in Customer/Connection					
2003					
2004	(0.1%)	(4.9%)	2.5%	(30.1%)	
2005	1.4%	0.3%	2.9%	(13.4%)	
2006	(4.5%)	(1.7%)	3.9%	(0.9%)	
2007	0.8%	0.0%	(5.3%)	(4.1%)	
2008	(0.4%)	(2.5%)	(9.2%)	9.9%	(1.6%)
2009	(2.7%)	(1.9%)	(4.8%)	(0.7%)	1.9%
2010	(0.3%)	(3.8%)	(0.3%)	(6.7%)	(12.5%)
2011	(1.5%)	(6.9%)	(3.1%)	2.6%	(2.1%)
Geometric Mean	**(0.9%)**	**(2.7%)**	**(1.8%)**	**(6.2%)**	**(3.7%)**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 usage and the resulting usage forecast is as follows:

Table 3.2.13: Forecast Annual kWh Usage per Customer/Connection					
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**
Forecast Annual kWh Usage per Customers/Connection					
2012	**7,753**	**30,710**	**1,110,658**	**689**	**36,347**
2013	**7,682**	**29,885**	**1,090,865**	**646**	**34,988**

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3.2.10 by the forecast of annual usage per customer/connection from Table 3.2.13. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table 3.2.14: Non-normalized Weather Billed Energy Forecast						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**	**Total**
NON-normalized Weather Billed Energy Forecast (GWh)						
2012 (Not Normalized)	**47.7**	**23.0**	**125.4**	**1.4**	**0.4**	**197.9**
2013 (Not Normalized)	**47.9**	**22.6**	**123.0**	**1.3**	**0.4**	**195.2**

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 200.7 GWh for 2012 and 200.6 GWh for 2013 before adjustments for loss of load in the GS > 50 kW class as well as 2012 and 2013 CDM programs.

The difference between the non-normalized and normalized forecast adjustments is 2.8 GWh in 2012 (i.e. 200.7 – 197.9) and 5.4 GWh in 2013 (i.e. 200.6 – 195.2). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Midland PUC for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3.2.15: Weather Sensitivity by Rate Class

Residential	GS<50	GS>50	Street Lighting	USL
Weather Sensitivity				
65%	65%	31%	0%	0%

For the GS > 50 kW class the weather sensitivity amount of 31% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. Midland PUC agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, Midland PUC has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 31%, or 65%.

The difference between the non-normalized and normalized forecast of 2.4 GWh in 2012 and 5.4 GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

A manual adjustment has been made to the GS> 50 kW class to reflect the impact of loss of load of 5.4 (GWh) from one customer in this class. Midland PUC was advised in May of 2012 that one of its major GS>50kW customers would be closing effective June, 2012. "After careful and lengthy analysis, we have concluded that our silica-processing operations in Midland are no longer economically viable" Unimin president Luke Anderson stated in a press release. This loss to the Midland community will see a loss of 18 jobs. As a result, Midland PUC's load will reduce by over 5.4MkWh or over 20kW based on current consumption levels. Although it is expected the property will be eventually sold, it is not expected a new customer will take over the business as a going concern. Recent newspaper articles have indicated a study will be done to determine the best possible use of the property – with park land being one of the options.

In addition a manual adjustment has been made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the "gross" impact of 2012 and 2013 CDM programs on the load forecast. The gross impact includes the net results measured by the OPA plus an estimate of the average net to gross adjustment reflecting gross and net savings information provided in the OPA 2006-2010 Final CDM Results. The net results provide a measurement of the program effectiveness used to achieve the LDC's targets. The gross results include the net results plus the estimated impact of customers participating in a program even if an incentive was not provided to participate. In the past this has been termed the level of "free ridership". In other words, the gross results include the results from those who participated in the program because there was an incentive plus those who participated even if there was not an incentive. In Midland PUC's view it is the gross level that impacts the load forecast.

The following table outlines the average net to gross factor of 59.2% based on information provided in the OPA 2006-2010 Final CDM Results for Midland PUC

Table 3.2.16: Average Net to Gross Percentage

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	489,107	437,952	51,154	11.7%
2007	1,595,097	765,816	829,280	108.3%
2008	1,939,592	1,191,886	747,706	62.7%
2009	3,910,931	2,539,169	1,371,762	54.0%
2010	4,457,229	2,887,748	1,569,481	54.3%
2011	4,162,575	2,590,841	1,571,734	60.7%
2012	4,078,028	2,554,143	1,523,885	59.7%
2013	4,040,877	2,535,176	1,505,701	59.4%
Total	24,673,435	15,502,731	9,170,704	59.2%

As previously discussed, the 2011 preliminary actual savings from 2011 CDM programs are known and have been used in the CDM activity variable included in the regression analysis supporting the prediction formula. However, knowing the 2011 results impacts on what saving will be needed from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following table the 2011 preliminary actual savings will contribute 39.6% to the four year target. In the following table the 2011 results are consistent with the information provided in Table 3.2.5. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 10.1% of the four year target each year in order to achieve the target.

Table 3.2.17: Schedule to Achieve 4 Year kWh CDM Target

4 Year 2011 to 2014 kWh target					
10,820,000					
	2011	2012	2013	2014	Total
2011 Programs	9.5%	10.0%	10.0%	10.0%	39.6%
2012 Programs		10.1%	10.1%	10.1%	30.2%
2013 Programs			10.1%	10.1%	20.1%
2014 Programs				10.1%	10.1%
	9.5%	20.1%	30.2%	40.2%	100.0%
kWh					
2011 Programs	1,032,669	1,084,940	1,084,940	1,084,940	4,287,487
2012 Programs		1,088,752	1,088,752	1,088,752	3,266,256
2013 Programs			1,088,752	1,088,752	2,177,504
2014 Programs				1,088,752	1,088,752
	1,032,669	2,173,692	3,262,444	4,351,196	10,820,000

The above table suggests that in 2012, the savings from 2012 will be 1,088,752 kWh on a net basis. However on a gross basis this amount would be 1,088,752 times 1.592 (i.e. the net to gross factor determined in Table 3.2.16) or 1,732,808 kWh. In Midland PUC's view, the 2012 load forecast should be adjusted by 1,732,808 kWh to reflect CDM savings from 2012 programs. As discussed above in regards to the CDM Activity variable, the persistent savings from 2011 programs in 2012 have been reflected in the prediction formula.

The above table also suggest that in 2013, the savings from 2012 and 2013 programs will be a 1,088,752 kWh times two or 2,177,504 kWh on a net basis. However on a gross basis this amount would be 2,177,504 times 1.592 (i.e. the net to gross factor determined in Table 3.2.16) or 3,465,616 kWh. In Midland PUC's view, the 2013 load forecast should be adjusted by 3,465,616 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is Midland PUC's understanding, as part of this application, expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also Midland PUC's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is Midland PUC's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in Table 3.2.17, Midland PUC expects to achieve 3,262,444 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the following table outlines how this expected savings has been allocated to rate class using the 2013 information from Table 3.2.14. The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3.2.21

Table 3.2.18: 2013 Expected Savings for LRAM Variance Account

	Residential	GS<50	GS>50	Street Lighting	USL	Total
kWh	800,063	376,966	2,056,024	22,372	7,018	3,262,444
kW where applicable			5,131	61		5,192

The following table outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3.2.19: Alignment of Non-normal to Weather Normal Forecast						
Year	**Residential**	**GS<50**	**GS>50**	**Street Lighting**	**USL**	**Total**
Non-normalized Weather Billed Energy Forecast (GWh)						
2012 Non-Normalized Bridge	**47.7**	**23.0**	**125.4**	**1.4**	**0.4**	**197.9**
2013 Non-Normalized Test	**47.9**	**22.6**	**123.0**	**1.3**	**0.4**	**195.2**
Weather Adjustment (GWh)						
2012	**1.0**	**0.5**	**1.3**	**0.0**	**0.0**	**2.8**
2013	**2.0**	**0.9**	**2.4**	**0.0**	**0.0**	**5.4**
Loss of Load Adjustment (GWh)						
2012						**0.0**
2013			**(5.4)**			**(5.4)**
CDM Adjustment (GWh)						
2012	**(0.4)**	**(0.2)**	**(1.1)**	**(0.0)**	**(0.0)**	**(1.7)**
2013	**(0.8)**	**(0.4)**	**(2.2)**	**(0.0)**	**(0.0)**	**(3.5)**
Weather Normalized Billed Energy Forecast (GWh)						
2012 Normalized Bridge	**48.4**	**23.3**	**125.6**	**1.4**	**0.4**	**199.0**
2013 Normalized Test	**49.0**	**23.1**	**117.8**	**1.3**	**0.4**	**191.7**

Billed KW Load Forecast

There are two rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW and Street Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 3.2.20: Historical Annual kW per Applicable Rate Class			
Year	**GS>50**	**Street Lighting**	**Total**
Billed Annual kW			
2004	385,769	2,841	388,610
2005	370,122	3,111	373,233
2006	362,602	3,130	365,732
2007	360,798	3,191	363,989
2008	346,096	3,191	349,287
2009	330,383	3,149	333,531
2010	332,210	3,939	336,149
2011	326,936	3,833	330,768

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2004 to 2011.

Table 3.2.21: Historical kW/KWh Ratio per Applicable Rate Class		
Year	**GS>50**	**Street Lighting**
Ratio of kW to kWh		
2004	0.2530%	0.2264%
2005	0.2358%	0.2827%
2006	0.2390%	0.2801%
2007	0.2488%	0.2975%
2008	0.2557%	0.2708%
2009	0.2541%	0.2692%
2010	0.2541%	0.2875%
2011	0.2559%	0.2733%
Average 2004 to 2011	**0.2496%**	**0.2734%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3.2.16 to provide the forecast of kW by rate class as shown below. The following table outlines the forecast of kW for the applicable rate classes.

Table 3.2.22: kW Forecast by Applicable Rate Class			
Year	**GS>50**	**Street Lighting**	**Total**
Predicted Billed kW			
2012 Normalized Bridge	**313,327**	**3,713**	**317,040**
2013 Normalized Test	**294,062**	**3,595**	**297,657**
Adjustment for Loss of Load - Add back	**13,491**		**13,491**
Adjustment for Loss of Load - Deduct	**(20,312)**		**(20,312)**
2013 Normalized Test - Adjusted	**287,241**	**3,595**	**290,836**

For 2013, the kW for the GS > 50 kW class has been adjusted to reflect that the loss of load has a higher kW/kWh ratio than average. Using the average kW/kWh ratio the kW reduction for the loss load would have been 13,491 kW but based on historical kW data for the loss of load the reduction will be 20,312 kW. As a result, an adjustment to add back 13,491 kW and a reduction of 20,312 kW has been made to the original 2013 value of 294,062 kW

Table 3.2.23 provides a summary of the billing determinants by rate class that are used to develop the proposed rates.

Table 3.2.23: Summary of Forecast

	2009 Board Approved	2009	2010	2011	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		217,320,554	220,975,056	214,550,355		
Predicted kWh Purchases		219,549,213	220,082,432	215,336,558	214,413,709	214,254,279
% Difference of actual and predicted purchases		1.0%	(0.4%)	0.4%		
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	6,018	6,031	6,053	6,084	6,157	6,231
kWh	49,791,737	48,075,570	48,092,980	47,612,325	48,361,864	49,023,071
GS<50						
Customers	729	720	740	741	748	755
kWh	27,650,878	25,357,510	25,080,220	23,384,283	23,264,544	23,098,239
GS>50						
Customers	103	111	112	113	113	113
kWh	139,428,070	129,998,410	130,739,365	127,781,460	125,556,253	117,836,449
kW	332,681	330,383	332,210	326,936	313,327	287,241
Sentinels						
Connections	22	20	0	0	0	0
kWh	15,948	6,809	0	0	0	0
kW	44	0	0	0	0	0
Street Lighting						
Connections	1,564	1,525	1,915	1,911	1,990	2,072
kWh	1,195,783	1,169,602	1,370,178	1,402,281	1,357,947	1,314,588
kW	3,052	3,149	3,939	3,833	3,713	3,595
USL						
Connections	12	12	12	12	12	12
kWh	513,550	528,996	462,670	453,113	432,346	412,397
Total						
Customer/Connections	8,448	8,419	8,832	8,861	9,019	9,182
kWh	218,595,966	205,136,897	205,745,412	200,633,462	198,972,953	191,684,743
kW from applicable classes	335,777	333,531	336,149	330,768	317,040	290,836

Appendix A

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-03	22,785,320	814.5	0	31	0	352	22,626,510
Feb-03	20,768,814	699	0	28	0	320	20,713,427
Mar-03	20,855,429	581.1	0	31	0	336	21,177,506
Apr-03	19,283,297	372.5	2.4	30	0	336	19,795,740
May-03	18,690,471	177.9	0	31	0	336	18,998,830
Jun-03	18,815,344	43.4	52.9	30	0	336	19,011,409
Jul-03	19,760,007	0.2	118.3	31	0	352	20,554,868
Aug-03	18,996,004	2	128	31	0	320	20,370,897
Sep-03	18,762,928	54.9	24	30	0	336	18,504,735
Oct-03	20,060,840	276	0	31	0	352	19,716,745
Nov-03	19,874,256	398.5	0	30	0	320	19,689,905
Dec-03	20,695,799	561.5	0	31	0	336	21,071,598
Jan-04	23,262,820	849.1	0	31	0	336	22,625,635
Feb-04	20,428,074	631.7	0	29	0	320	20,654,500
Mar-04	20,893,227	487.3	0	31	0	368	21,055,276
Apr-04	18,810,339	331.5	0	30	0	336	19,526,961
May-04	18,658,326	158.9	8.6	31	0	320	18,868,651
Jun-04	18,844,589	44.2	31.6	30	0	352	18,786,934
Jul-04	19,695,448	3.6	86.4	31	0	336	19,757,544
Aug-04	19,917,220	12.8	59.6	31	0	336	19,279,774
Sep-04	19,428,366	30	41.2	30	0	336	18,708,722
Oct-04	19,403,814	226.3	1.5	31	0	320	19,093,101
Nov-04	20,293,300	379.1	0	30	0	352	19,974,598
Dec-04	21,661,750	643.4	0	31	0	336	21,514,142
Jan-05	23,259,549	770	0	31	0	320	22,001,441
Feb-05	20,377,421	616.4	0	28	0	320	20,267,101
Mar-05	21,345,969	608.6	0	31	0	352	21,513,937
Apr-05	18,877,708	306.8	0	30	0	336	19,393,496
May-05	18,671,477	189.4	0.8	31	0	336	19,076,715
Jun-05	20,632,122	8.9	146.3	30	0	352	20,853,735
Jul-05	21,248,207	0	188.7	31	0	320	21,554,797
Aug-05	21,038,906	0.2	140.7	31	0	352	20,995,748
Sep-05	19,417,528	22.6	52.1	30	0	336	18,883,272
Oct-05	19,638,994	220.2	7.6	31	0	320	19,180,201
Nov-05	20,308,386	388.4	0	30	0	352	20,024,850
Dec-05	21,410,448	665.3	0	31	0	320	21,435,698
Jan-06	21,748,047	551.8	0	31	5,615	336	20,977,197
Feb-06	20,180,939	604.3	0	28	11,230	320	20,117,744
Mar-06	21,466,113	516.6	0	31	16,844	368	21,087,635
Apr-06	18,096,529	293.3	0	30	22,459	304	18,763,079
May-06	18,755,945	136.9	26	31	28,074	352	19,266,921
Jun-06	19,278,924	19.5	73.6	30	33,689	352	19,228,194
Jul-06	20,503,638	0	167.3	31	39,303	320	20,839,686
Aug-06	19,883,253	4.2	101.6	31	44,918	352	19,911,890
Sep-06	18,180,887	80.9	12.9	30	50,533	320	17,849,777
Oct-06	18,826,744	288.3	1.1	31	56,148	336	19,197,147
Nov-06	20,237,847	382.2	0	30	61,763	352	19,529,485
Dec-06	20,414,607	500.5	0	31	67,377	304	19,853,522

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-07	22,474,389	647.1	0	31	66,830	352	21,222,214
Feb-07	20,926,383	740.1	0	28	66,282	320	20,439,849
Mar-07	21,292,238	546.7	0	31	65,735	352	20,687,896
Apr-07	18,821,018	356.4	0	30	65,187	320	18,974,948
May-07	19,052,207	136.4	22.4	31	64,639	352	18,919,925
Jun-07	19,756,752	16.5	99.2	30	64,092	336	19,298,058
Jul-07	19,704,370	3.2	106.1	31	63,544	336	19,667,934
Aug-07	20,438,454	5.2	141	31	62,997	352	20,557,578
Sep-07	18,405,018	36.9	47.5	30	62,449	304	18,013,486
Oct-07	19,047,460	137.7	19.8	31	61,901	352	18,896,250
Nov-07	19,941,321	462.5	0	30	61,354	352	19,966,439
Dec-07	20,294,567	630.7	0	31	60,806	304	20,606,191
Jan-08	21,313,449	623.5	0	31	66,732	352	21,096,480
Feb-08	20,093,547	674.7	0	29	72,658	320	20,341,586
Mar-08	20,433,659	610.2	0	31	78,584	304	20,358,922
Apr-08	18,173,874	253.9	0	30	84,509	352	18,665,157
May-08	17,667,199	193.5	2.5	31	90,435	336	18,452,588
Jun-08	18,711,079	22.7	71.5	30	96,361	336	18,542,168
Jul-08	19,677,801	1	111	31	102,287	352	19,651,664
Aug-08	19,059,244	12.7	64	31	108,213	320	18,360,799
Sep-08	18,058,635	59	26.7	30	114,138	336	17,723,614
Oct-08	18,400,533	278.6	0	31	120,064	352	18,834,006
Nov-08	18,807,351	451.6	0	30	125,990	304	18,846,163
Dec-08	19,715,641	654.6	0	31	131,916	336	20,584,727
Jan-09	20,784,437	830.2	0	31	144,174	336	21,441,903
Feb-09	17,971,853	606.4	0	28	156,433	304	18,852,436
Mar-09	19,066,951	533.8	0	31	168,692	352	19,849,329
Apr-09	17,089,677	305.8	1.2	30	180,951	320	17,863,313
May-09	16,617,656	158.8	6.9	31	193,209	320	17,390,784
Jun-09	17,052,759	49.3	34.2	30	205,468	352	17,328,203
Jul-09	17,788,588	6.2	43.7	31	217,727	352	17,491,887
Aug-09	18,640,724	9.8	91	31	229,985	320	17,965,923
Sep-09	17,199,410	55.2	20.9	30	242,244	336	16,630,942
Oct-09	17,690,863	287.8	0	31	254,503	336	17,686,022
Nov-09	17,709,543	361.2	0	30	266,762	320	17,497,346
Dec-09	19,708,093	631.3	0	31	279,020	352	19,551,125
Jan-10	20,632,805	720	0	31	273,117	320	19,689,850
Feb-10	18,505,312	598.3	0	28	267,213	304	17,980,251
Mar-10	18,433,778	422.8	0	31	261,309	368	18,749,305
Apr-10	16,541,731	225.1	0	30	255,405	320	16,846,859
May-10	17,814,847	107.9	45.7	31	249,501	320	17,458,460
Jun-10	17,553,229	21.7	58.7	30	243,598	352	17,376,146
Jul-10	19,798,893	1.8	164.9	31	237,694	336	19,511,919
Aug-10	19,524,656	2.1	138.8	31	231,790	336	19,043,985
Sep-10	17,319,540	78.1	31.5	30	225,886	336	17,085,638
Oct-10	17,192,204	241.6	0	31	219,982	320	17,502,174
Nov-10	18,120,753	405.3	0	30	214,079	336	18,321,962
Dec-10	19,537,309	676.2	0	31	208,175	368	20,515,883

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-11	20,299,144	775.3	0	31	222,603	336	20,558,760
Feb-11	18,184,464	654.2	0	28	237,031	304	18,508,003
Mar-11	19,484,270	572.8	0	31	251,460	368	19,633,477
Apr-11	16,794,726	332.3	0	30	265,888	320	17,347,718
May-11	16,740,139	134.1	13	31	280,317	336	16,918,342
Jun-11	16,821,047	19	52.2	30	294,745	352	16,851,140
Jul-11	19,127,628	0	198.5	31	309,173	320	19,436,630
Aug-11	18,487,865	0	122.2	31	323,602	352	18,211,696
Sep-11	16,740,313	48.2	39.7	30	338,030	336	16,246,850
Oct-11	16,580,770	235.5	2.4	31	352,458	320	16,525,787
Nov-11	17,060,831	342.1	0	30	366,887	352	17,030,110
Dec-11	18,229,158	534	0	31	381,315	336	18,068,047
Jan-12		731	0	31	369,306	336	19,223,834
Feb-12		647	0	29	357,297	320	18,064,624
Mar-12		542	0	31	345,288	352	18,574,182
Apr-12		309	0	30	333,279	320	16,723,695
May-12		155	14	31	321,270	352	16,936,119
Jun-12		27	69	30	309,261	336	16,923,689
Jul-12		2	132	31	297,252	336	18,412,094
Aug-12		5	110	31	285,243	352	18,281,059
Sep-12		52	33	30	273,234	304	16,232,933
Oct-12		244	4	31	261,225	352	17,659,889
Nov-12		397	0	30	249,216	352	18,205,444
Dec-12		611	0	31	237,207	304	19,176,147
Jan-13		731	0	31	247,126	352	20,329,861
Feb-13		647	0	28	257,044	304	18,320,703
Mar-13		542	0	31	266,962	320	18,775,196
Apr-13		309	0	30	276,881	352	17,530,158
May-13		155	14	31	286,799	352	17,193,898
Jun-13		27	69	30	296,717	320	16,825,140
Jul-13		2	132	31	306,635	352	18,534,283
Aug-13		5	110	31	316,554	336	17,854,563
Sep-13		52	33	30	326,472	320	16,027,175
Oct-13		244	4	31	336,390	352	17,097,803
Nov-13		397	0	30	346,309	336	17,287,029
Dec-13		611	0	31	356,227	320	18,478,470

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

VARIANCE ANALYSIS ON THROUGHPUT REVENUE:

A summary of historical and forecast operating revenues is presented in Exhibit 3, Tab 1. Midland PUC's distribution revenue has been calculated using its most recently approved rates. In particular, delivery rates are based on the EB-2011-0182 Decision and Order dated April 4, 2012 for 2012 information. Throughput revenue does not include commodity-related revenue.

A variance analysis for the other net operating revenue will be provided further in Tab 3 Schedule 2 of this Exhibit.

2009 Board Approved:

Midland PUC's Total 2009 Board Approved operating revenue was forecast to be $ 3,621,509. Throughput revenue of $ 3,390,378 represented 93.6% of total operating revenue. Other net operating revenue accounts for the remaining $ 231,131.

2009 Actual:

Midland PUC's operating revenue in fiscal 2009 was $ 3,484,347. Throughput revenue was $ 3,108,622 or 89.2% of total revenues. Other net operating revenue accounts for the remaining $ 375,725.

Table 3.3.1: Comparison 2009 Actual to 2009 Board Approved – Throughput Revenue:

Operating Revenue	2009 OEB Approved	2009 Actual	Variance	% Variance
Distribution Revenue				
Residential	$ 1,846,829	$ 1,793,665	-$ 53,164	-2.9%
GS<50kW	$ 529,784	$ 485,508	-$ 44,276	-8.4%
GS>50kW	$ 922,838	$ 766,705	-$ 156,134	-16.9%
Streetlights	$ 68,195	$ 48,881	-$ 19,314	-28.3%
Unmetered Scattered Load	$ 17,473	$ 13,708	-$ 3,765	-21.5%
Sentinel Lights	$ 5,259	$ 156	-$ 5,102	-97.0%
MicroFit	$ -	$ -	$ -	0.0%
Total Operating Revenues	**$ 3,390,378**	**$ 3,108,622**	**-$ 281,756**	**-8.3%**

Throughput revenue for 2009 was 8.3% or $ 281,756 lower than the amounts approved in the 2009 COS Application primarily due to lower kWh usage in all customer classes. As indicated above, the reductions in kWh are a result of three factors - seasonal weather conditions, economic downturn in the manufacturing sector and the success of conservation initiatives.

In addition, timing differences between the 2009 Actual distribution revenues which are based on the fiscal year of January 1 to December 31, 2009, and the 2009 COS Application distribution revenues, which are based on the rate year of May 1 2009 to April 30, 2010 also contribute to the variance, since the 2009 rates did not come into effect until May 2009. The 2009 Actual distribution revenues are derived based on 4 months at the 2008 approved distribution rates and 8 months at the 2009 Approved distribution rates.

Table 3.3.2 below compares the 2009 EDR Approved billing quantities to the 2009 Actual quantities.

Table 3.3.2: Comparison 2009 Actual to 2009 Board Approved Billing Quantities:

Rate Class	Customers/Connections			kWh			kW		
	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance
Residential	6018	6,031	13	49,791,737	48,075,570	- 1,716,167			
GS<50kW	729	720	-9	27,650,878	25,357,510	- 2,293,368			
GS>50kW	103	111	8	139,428,070	129,998,410	- 9,429,660	332,681	330,383	- 2,298
Streetlights	1564	1,525	-39	1,195,783	1,169,602	- 26,181	3,052	3,149	96
Unmetered Scattered Load	12	12	0	513,550	528,996	15,446			
Sentinel Lights	22	20	-2	15,948	6,809	- 9,139			
MicroFit									
Total	**8448**	**8419**	**-29**	**218,595,966**	**205,136,897**	**- 13,459,069**	**335,733**	**333,531**	**- 2,202**

2010 Actual:

Midland PUC's operating revenue in fiscal 2010 was $ 3,693,225, as shown in Table 3.1.1. Throughput revenue totaled $ 3,363,825 or 91.1% of total revenues. Other net operating revenue accounts for the remaining revenue of $ 329,399.

Table 3.3.3: Comparison 2009 Actual to 2010 Actual – Throughput Revenue:

Operating Revenue	2009 Actual	2010 Actual	Variance	% Variance
Distribution Revenue				
Residential	$ 1,793,665	$ 1,813,778	$ 20,113	1.1%
GS<50kW	$ 485,508	$ 523,485	$ 37,977	7.8%
GS>50kW	$ 766,705	$ 911,364	$ 144,660	18.9%
Streetlights	$ 48,881	$ 99,086	$ 50,205	102.7%
Unmetered Scattered Load	$ 13,708	$ 16,113	$ 2,405	17.5%
Sentinel Lights	$ 156	$ -	-$ 156	-100.0%
MicroFit	$ -	$ -	$ -	0.0%
Total Operating Revenues	$ 3,108,622	$ 3,363,825	$ 255,203	8.2%

The 2010 throughput revenue was $ 255,203 or 8.2% higher than the 2009 actual revenue. Table 3.3.4 below provides a comparison of consumption per class for the years 2009 and 2010. Although Residential customer load remained constant, the actual number of customers increased by 22. On the other hand the GS<50 customer numbers increased by 20, however, load decreased by over 277,290 kWh. The bulk of the increase in load was due to the GS>50 class – 740,955 kWh. Overall, load increased by 608,515 kWh's.

Table 3.3.4: Comparison 2009 Actual to 2010 Actual Billing Quantities:

	Customers/Connections			kWh			kW		
Rate Class	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance
Residential	6,031	6,053	22	48,075,570	48,092,980	17,409			
GS<50kW	720	740	20	25,357,510	25,080,220	- 277,290			
GS>50kW	111	112	1	129,998,410	130,739,365	740,955	330,383	332,210	1,827
Streetlights	1,525	1,915	390	1,169,602	1,370,178	200,576	3,149	3,939	790
Unmetered Scattered Load	12	12	0	528,996	462,670	- 66,326			
Sentinel Lights	20	0	-20	6,809	-	- 6,809			
MicroFit									
Total	**8419**	**8832**	**413**	**205,136,897**	**205,745,412**	**608,515**	**333,531**	**336,149**	**2,617**

2011 Actual:

Midland PUC's operating revenue for 2011 was $ 3,759,004 , as shown in Exhibit 3, Tab 1, Table 3.1.1. Throughput revenue was $ 3,419,088 or *91.0%* of total revenues. Net other operating revenue accounts for the remaining revenue of $ 339,917.

Table 3.3.5: Comparison 2010 Actual to 2011 Actual – Throughput Revenue:

Operating Revenue	2010 Actual	2011 Actual	Variance	% Variance
Distribution Revenue				
Residential	$ 1,813,778	$ 1,816,939	$ 3,162	0.2%
GS<50kW	$ 523,485	$ 486,941	-$ 36,543	-7.0%
GS>50kW	$ 911,364	$ 980,025	$ 68,660	7.5%
Streetlights	$ 99,086	$ 118,099	$ 19,013	19.2%
Unmetered Scattered Load	$ 16,113	$ 17,084	$ 971	6.0%
Sentinel Lights	$ -	$ -	$ -	0.0%
MicroFit	$ -	$ -	$ -	0.0%
Total Operating Revenues	$ 3,363,825	$ 3,419,088	$ 55,262	1.6%

Throughput revenue in 2011 was 1.6% or $ 55,262 higher than in 2010 due in large part to the Lost Revenue Adjustment Revenue (LRAM) recovery of $ 215,600 in 2011, 8 months of which or $ 143,700 was recovered in 2011. Over $ 66,000 of the 2011 recovery is attributed to the GS>50kW class. Table 3.3.6 below provides a comparison of consumption per class for the years 2010 and 2011. Overall consumption has decreased by 5,111,950 kWhs over 2010. The decrease in consumption was experienced across all customer classes, with over 2,957,905 kWh decrease in the GS>50 kW class.

Table 3.3.6: Comparison 2010 Actual to 2011 Actual Billing Quantities:

	Customers/Connections			kWh			kW		
Rate Class	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance
Residential	6,053	6,084	31	48,092,980	47,612,325	- 480,654			
GS<50kW	740	741	1	25,080,220	23,384,283	- 1,695,937			
GS>50kW	112	113	1	130,739,365	127,781,460	- 2,957,905	332,210	326,936	- 5,274
Streetlights	1,915	1,911	-4	1,370,178	1,402,281	32,103	3,939	3,833	- 106
Unmetered Scattered Load	12	12	0	462,670	453,113	- 9,557			
Sentinel Lights	0	0	0	-	-	-			
MicroFit									
Total	**8832**	**8861**	**29**	**205,745,412**	**200,633,462**	**- 5,111,950**	**336,149**	**330,768**	**- 5,380**

2012 Bridge Year (CGAAP & MIFRS):

As shown in Exhibit 3, Tab 1, Table 3.1.1, Midland PUC's operating revenue in the 2012 Bridge Year is forecast to be $ 3,949,446 under CGAAP and $ 3,873,877 under MIFRS. Throughput revenue is forecast at $ 3,624,391 of total revenues under both CGAAP and MIFRS. Net other operating revenue accounts for the remaining revenue of $ 325,055 under CGAAP and $ 249,486 under MIFRS .

Table 3.3.7: Comparison 2011 Actual to 2012 Bridge Year – Throughput Revenue:

Operating Revenue	2011 Actual	2012 Bridge (CGAAP) & (MIFRS)	Variance	% Variance
Distribution Revenue				
Residential	$ 1,816,939	$ 2,053,180	$ 236,241	13.0%
GS<50kW	$ 486,941	$ 549,308	$ 62,366	12.8%
GS>50kW	$ 980,025	$ 885,752	-$ 94,273	-9.6%
Streetlights	$ 118,099	$ 121,089	$ 2,990	2.5%
Unmetered Scattered Load	$ 17,084	$ 15,063	-$ 2,021	-11.8%
Sentinel Lights	$ -	$ -	$ -	0.0%
MicroFit	$ -	$ -	$ -	0.0%
Total Operating Revenues	$ 3,419,088	$ 3,624,391	$ 205,304	6.0%

Throughput revenue in 2012 is projected to be 6.0% or $ 205,304 higher than in 2011 due to the smart meter recovery included in rates effective May 1, 2012. In addition, the balance of the 2011 Lost Revenue Adjustment Revenue (LRAM) recovery of $ 72,000 was recovered in 2012.

Table 3.3.8 below provides a comparison of consumption per class for the years 2011 and 2012. Overall consumption has decreased by 1,660,509 kWhs over 2011. The decrease in consumption in the GS>50 kW class was partially offset by the increase in consumption in the residential class.

Table 3.3.8: Comparison 2011 Actual to 2012 Bridge Year Billing Quantities:

	Customers/Connections			kWh			kW		
Rate Class	2011 Actual	2012 Bridge (CGAAP) & (MIFRS)	Variance	2011 Actual	2012 Bridge (CGAAP) & (MIFRS)	Variance	2011 Actual	2012 Bridge (CGAAP) & (MIFRS)	Variance
Residential	6,084	6,157	73	47,612,325	48,361,864	749,538			
GS<50kW	741	748	7	23,384,283	23,264,544	- 119,739			
GS>50kW	113	113	0	127,781,460	125,556,253	- 2,225,208	326,936	313,327	- 13,608
Streetlights	1,911	1,990	79	1,402,281	1,357,947	- 44,334	3,833	3,713	- 119
Unmetered Scattered Load	12	12	0	453,113	432,346	- 20,767			
Sentinel Lights	0	0	0	-	-	-			
MicroFit									
Total	**8861**	**9019**	**158**	**200,633,462**	**198,972,953**	**- 1,660,509**	**330,768**	**317,040**	**- 13,728**

2013 Test Year:

As shown in Exhibit 3, Tab 1, Table 3.1.1, Midland PUC's operating revenue is forecast to be $ 4,101,077 under MIFRS. Throughput revenue totals $ 3,837,473 or *93.6%* of total revenues under MIFRS. Other net operating revenue accounts for the remaining revenue of $ 263,604 under MIFRS .

Table 3.3.9: Comparison 2012 Bridge Year to 2013 Test Year – Throughput Revenue:

Operating Revenue	2012 Bridge (MIFRS)	2013 Test Year (MIFRS)	Variance	% Variance
Distribution Revenue				
Residential	$ 2,053,180	$ 2,046,360	-$ 6,820	-0.3%
GS<50kW	$ 549,308	$ 584,548	$ 35,241	6.4%
GS>50kW	$ 885,752	$ 1,036,446	$ 150,695	17.0%
Streetlights	$ 121,089	$ 128,464	$ 7,376	6.1%
Unmetered Scattered Load	$ 15,063	$ 6,023	-$ 9,040	-60.0%
Sentinel Lights	$ -	$ -	$ -	0.0%
MicroFit	$ -	$ -	$ -	0.0%
Total Operating Revenues	$ 3,624,391	$ 3,801,842	$ 177,451	4.9%

Total throughput operating revenue is forecast to be $ 177,451 or 4.9% higher than the 2012 Bridge Year amounts. Table 3.3.10 below provides a comparison of consumption per class for the years 2012 and 2013.

Table 3.3.10: Comparison 2012 Bridge Year to 2013 Test Year Billing Quantities:

	Customers/Connections			kWh			kW		
Rate Class	2012 Bridge (CGAAP) & (MIFRS)	2013 Test Year (MIFRS)	Variance	2012 Bridge (CGAAP) & (MIFRS)	2013 Test Year (MIFRS)	Variance	2012 Bridge (CGAAP) & (MIFRS)	2013 Test Year (MIFRS)	Variance
Residential	6,157	6,157	0	48,361,864	49,023,071	661,207			
GS<50kW	748	755	7	23,264,544	23,098,239	- 166,305			
GS>50kW	113	113	0	125,556,253	117,836,449	- 7,719,803	313,327	287,241	- 26,086
Streetlights	1,990	2,072	82	1,357,947	1,314,588	- 43,359	3,713	3,595	- 119
Unmetered Scattered Load	12	12	0	432,346	412,397	- 19,949			
Sentinel Lights	0	0	0	-	-	-			
MicroFit									
Total	**9019**	**9108**	**89**	**198,972,953**	**191,684,743**	**- 7,288,210**	**317,040**	**290,836**	**- 26,204**

Overall consumption has decreased by 7,288,210 kWhs over 2012 bridge year. As discussed in Exhibit 3, Tab 2 the decrease in consumption in the GS>50 kW class is mainly due to the loss of a major customer in mid-2012.

TRANSFORMER ALLOWANCE

Midland PUC currently provides a Transformer Ownership Allowance Credit of $0.60 per kW of demand per month for all customers who own their own transformer facilities.

Midland PUC is proposing to maintain the rate of $0.60 per kW of demand per month for the 2013 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER OPERATING REVENUE

Table 3.3.11 provides a summary of Other Operating Revenue between 2009 Actual through to 2013 Test Year Amounts.

Table 3.3.11: Summary of Other Operating Revenue

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 Pr	$ -	$ 2,543	$ 2,433	$ -	$ 75,569	$ 22,596
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	$ -	$ -	$ -
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	-$ 77,155	-$ 1,586	-$ 28,304
Total		-$ 375,725	-$ 329,399	-$ 339,917	-$ 325,055	-$ 249,486	-$ 263,604

OVERVIEW

Midland PUC's service revenue requirement for the purposes of this application is $ 4,065,446 and the base revenue requirement is $ 3,801,842. The materiality threshold used to analyze Other Operating Revenue accounts in accordance with the Filing Requirements is $50,000 for distributors with a distribution revenue requirement less than or equal to $10 million.

Midland PUC will, however, describe variances that are below the materiality threshold in order to provide a meaningful analysis of the activity in the Other Operating Revenue accounts, as follows:

SPECIFIC SERVICE CHARGES

Midland PUC is proposing to make changes to specific service charges by adding the Interval Meter Load Management Tool at $25.00 per month. The 2009 COS Application included the revenues of $2,400 per year in the Miscellaneous Service Revenue offsets, however, due to inadvertence, the rate was not included in the tariff sheet. Midland PUC would request the Board approve the charges consistent with the Board Approved 2009 Cost of Service Application and the Interval Meter Load Management Tool charge. Table 3.3.12 illustrates the 2009 COS Application Specific Service Charge Rates and the proposed 2013 Specific Service Charge Tariff. Table 3.3.13 details the historical and forecast revenues for each specific service charge attributable to USoA #4235 in addition to the current approved and proposed 2013 Test Year rates. A discussion for the proposed changes and additions to specific charges follows Table 3.3.13.

Table 3.3.12: Specific Service Charge Tariff

Description	Board Approved 2009 Rate	2013 Proposed Rate
Notification Charge	$ 15.00	$ 15.00
Account History	$ 15.00	$ 15.00
Returned Cheque Charge (plus bank charges)	$ 15.00	$ 15.00
Legal Letter Charge	$ 15.00	$ 15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicalble)	$ 30.00	$ 30.00
Late Payment - per month	1.50%	1.50%
Late Payment - per annum	19.56%	19.56%
Disconnect/Reconnect at meter - during regular hours	$ 65.00	$ 65.00
Disconnect/Reconnect at meter - after regular hours	$ 185.00	$ 185.00
Disconnect/Reconnect at pole - during regular hours	$ 185.00	$ 185.00
Disconnect/Reconnect at pole - after regular hours	$ 415.00	$ 415.00
Specific Charge for Access to Power Poles	$ 22.35	$ 22.35
Install/Remove load control device - during regular hours	$ 65.00	$ 65.00
Install/Remove load control device - after regular hours	$ 185.00	$ 185.00
Temporary service install & remove - overhead - no transformer	$ 500.00	$ 500.00
Temporary service install & remove - underground - no transformer	$ 300.00	$ 300.00
Interval Meter Load Management Tool		$ 25.00

Table 3.3.13: Account 4235 - Miscellaneous Service Revenues

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
NSF Charges	-$ 1,383	-$ 1,980	-$ 1,755	-$ 1,800	-$ 1,800	-$ 1,800
Account Set Up Charges	-$ 33,690	-$ 36,510	-$ 34,470	-$ 34,200	-$ 34,200	-$ 34,200
Interval Meter Load Management Tool	-$ 3,626	-$ 2,358	-$ 4,485	-$ 5,400	-$ 5,400	-$ 5,400
Account History	-$ 360	$ -	-$ 30	-$ 100	-$ 100	-$ 100
Lawyer Letters	-$ 86	-$ 44	-$ 45	-$ 100	-$ 100	-$ 100
Reconnection Fee	-$ 10,120	-$ 9,220	-$ 6,880	-$ 7,000	-$ 7,000	-$ 7,000
Notice Letter Charge	-$ 55,205	-$ 57,889	-$ 55,680	-$ 59,400	-$ 59,400	-$ 59,400
Temporary Services - Underground	-$ 1,200	$ -	-$ 300	-$ 600	-$ 600	-$ 600
Late Payment Penalty Assessment	$ -	$ -	-$ 18,252	-$ 13,500	-$ 13,500	$ -
Total	-$ 105,670	-$ 108,002	-$ 121,897	-$ 122,100	-$ 122,100	-$ 108,600

Miscellaneous Service Revenue has remained relatively constant from 2009 to forecast 2013.

Table 3.3.14
Account 4325: Revenues from Merchandising, Jobbing
Account 4330: Expenses from Merchandising, Jobbing

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Rev From Merchandising, Jobbing	-$ 34,900	-$ 85,867	-$ 78,046	-$ 92,500	-$ 92,500	-$ 94,300
Total	-$ 34,900	-$ 85,867	-$ 78,046	-$ 92,500	-$ 92,500	-$ 94,300

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Costs and Exp Merchandising, Jobbing	$ 18,636	$ 63,870	$ 54,180	$ 63,000	$ 63,000	$ 64,500
Total	$ 18,636	$ 63,870	$ 54,180	$ 63,000	$ 63,000	$ 64,500

Revenues and Expenses from Merchandising, Jobbing have remained relatively on budget through 2010 and 2011 and have increased substantially over 2009 Actuals.

Table 3.3.15
Account 4375: Revenues from Non-Utility Operations
Account 4380: Expenses from Non-Utility Operations

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Streetlight Revenues	-$ 67,851	-$ 49,782	-$ 60,591	-$ 57,600	-$ 57,600	-$ 58,800
OPA Revenues - Conservation Programs	-$ 235,799	-$ 175,536				
Total	-$ 303,650	-$ 225,318	-$ 60,591	-$ 57,600	-$ 57,600	-$ 58,800

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Streetlight Expenses	$ 40,497	$ 36,599	$ 42,125	$ 36,800	$ 36,800	$ 37,700
OPA Expenses - Conservation Programs	$ 189,205	$ 135,695				
Community Initiatives Funding		$ 5,595				
Total	$ 229,702	$ 177,889	$ 42,125	$ 36,800	$ 36,800	$ 37,700

Revenues and expenses from Non-Utility Operations increased in 2009 and 2010 due to the OPA Conservation Programs and the Community Initiatives Funding.

Table 3.3.16
Account 4405: Interest and Dividend Income

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Bank Deposit Interest	-$ 1,019	-$ 3,362	-$ 7,038			
Interest on PILS paid from CRA	-$ 5,736	$ -	$ -			
Regulatory Asset Interest	-$ 30,729	-$ 30,273	-$ 44,379			
Total	-$ 37,483	-$ 33,635	-$ 51,417	$ -	$ -	$ -

Interest income has increased due to the increase in interest revenues as a result of regulatory asset balances.

Table 3.3.17
Account 4080: Standard Supply Service Charge

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Standard Supply Admin Chg ($.25)	-$ 16,935	-$ 17,355	-$ 17,883	-$ 19,500	-$ 19,500	-$ 19,500
Total	-$ 16,935	-$ 17,355	-$ 17,883	-$ 19,500	-$ 19,500	-$ 19,500

The standard supply service charge has remained constant over the years 2009 to 2011. 2012 and 2013 will see an increase due to the increase in customer numbers.

Table 3.3.18
Account 4210: Rent from Electric Property

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Building Rental	-$ 53,148	-$ 50,940	-$ 48,834	-$ 45,500	-$ 45,500	-$ 46,400
Pole Rental	-$ 37,018	-$ 31,954	-$ 31,804	-$ 31,800	-$ 31,800	-$ 31,800
Total	-$ 90,166	-$ 82,895	-$ 80,638	-$ 77,300	-$ 77,300	-$ 78,200

Rent from Electric Property has decreased in comparison to 2009. Pole rental has decreased by $5,000 and rent from buildings has decreased by $7,000 in comparison to 2009. Building rental has decreased as less space has been rented.

Table 3.3.19
Account 4220: Other Electric Revenues

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				CGAAP	MIFRS	MIFRS
Scrap Metal Revenues	-$ 1,363	-$ 835	-$ 5,664	-$ 5,600	-$ 5,600	-$ 5,600
Total	-$ 1,363	-$ 835	-$ 5,664	-$ 5,600	-$ 5,600	-$ 5,600

Midland PUC has increased scrap metal revenues over 2009 and 2010 levels and expects revenues to remain constant over 2012 and 2013.

Table 3.3.20
Account 4225: Late Payment Charges

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				**CGAAP**	**MIFRS**	**MIFRS**
Late Payment Fees paid by Customers	-$ 20,871	-$ 19,795	-$ 22,518	-$ 23,400	-$ 23,400	-$ 23,400
Total	-$ 20,871	-$ 19,795	-$ 22,518	-$ 23,400	-$ 23,400	-$ 23,400

Late Payment Fees paid by customers on overdue accounts are expected to increase slightly over 2011 levels.

Table 3.3.21
Account 4357: Gain on Retirement of Utility and Other Property

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				**CGAAP**	**MIFRS**	**MIFRS**
Gain on disposal of vehicle	-$ 525					
Gain on disposal of truck	-$ 12,500			-$ 26,855	-$ 26,855	$ -
Total	-$ 13,025	$ -	$ -	-$ 26,855	-$ 26,855	$ -

Midland PUC expects to realize a gain on the disposal of the large trucks in 2012. No gains are expected to be recovered in 2013.

Table 3.3.22
Account 4362: Loss on Retirement of Utility and Other Property

	2009 Actual	2010 Actual	2011 Actual	Bridge Year	Bridge Year	Test Year
Reporting Basis				**CGAAP**	**MIFRS**	**MIFRS**
Gain on Enerconnect Limited Partnership redemption		-$ 1,841				
Loss on disposal of generator		$ 4,384				
Loss on disposal of vehicle			$ 2,433			
Loss on disposal of distribution assets					$ 75,569	$ 22,596
Total	$ -	$ 2,543	$ 2,433	$ -	$ 75,569	$ 22,596

Midland PUC has recorded losses on disposal of assets in the years 2010 and 2011. Midland PUC expects to incur losses on the disposal of distribution assets in 2012 and 2013 as we transition to the MIFRS accounting requirements. The losses would not be recorded under CGAAP financial presentation.

Request for Additional Specific Service Charge

Midland PUC also proposes to add a new rate to recover costs for the Interval Meter Load Management Tool at $25.00 per month as discussed in detail in Exhibit 3, Tab 3, Schedule 2 above and in Exhibit 8.

Request to Maintain Current Rates and Specific Charges

Midland PUC anticipates no material changes to the Specific Service Charge revenue and proposes to also maintain the current rates.