MIDLAND POWER UTILITY CORPORATION
16984 Highway#12 P.O. Box 820
Midland Ontario L4R 4P4

August 15, 2008

Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

Midland Power Utility Corporation – License #ED-2002-0541
Requirement and Rate Application for the 2009, 2010 and 2011 rate years
OEB File No.: EB-2008-0236

Please find attached Midland Power Utility Corporation's Application for revenue requirements and corresponding rates for three individual and successive rate years commencing May 1, 2009 and ending April 30, 2012. This application is being filed pursuant to the Board's e-Filing Services. We will be delivering two paper copies of the Application to the Board over the next few days.

Yours very truly,

MIDLAND POWER UTILITY CORPORATION

Phil Marley, CMA
President & CEO
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Midland Power Utility Corporation

2009 EDR Application

EB-2008-0236

Submitted: 15 August, 2008

Main Index

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

Application Summary

Application

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Midland Power Utility Corporation to the Ontario Energy Board by an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2009;

APPLICATION

Introduction

The Applicant is Midland Power Utility Corporation (referred to in this Application as “MPUC”). MPUC is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the Town of Midland.

MPUC hereby applies to the Ontario Energy Board (the “OEB”) pursuant to section 78 of the Ontario Energy Board Act, 1998 as amended (the “OEB Act”) for approval of its proposed distribution rates and other charges, effective May 1, 2009.

Except where specifically identified in the Application, MPUC followed Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated November 14, 2006 (the “Filing Requirements”) in preparing this Application.

Proposed Distribution Rates and Other Charges

The Schedule of Rates and Charges proposed in this Application is identified in Exhibit 1, Tab 1, Schedule 5 and the material being filed in support of this Applications sets out MPUC’s approach to its 2009 distribution rates and charges.

Proposed Effective Date of Rate Order

MPUC requests that the OEB make its Rate Order effective May 1, 2009 in accordance with the Filing Requirements. MPUC requests that, if for any reason, final rates are not approved and effective May 1, 2009 that interim rates be approved effective May 1, 2009 until final rates are approved by the Board. MPUC requests the interim rates would be the current approved rates.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

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

- the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;
- the proposed rates are necessary to meet MPUC's Market Based Return ("MBRR"), Debt Rate and Payments in Lieu of Taxes ("PILS") requirements;
- 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 MPUC or the implementation of any other mitigation measures; and
- such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

MPUC applies for an Order or Orders approving the proposed distribution rates and other charges set out in this Application as just and reasonable rates and charges pursuant to section 78 of the OEB Act, to be effective May 1, 2009, or as soon as possible thereafter.

DATED at Midland, Ontario this 14th day of August, 2008

Midland Power Utility Corporation

Phil Marley, CMA
President & CEO

Summary of Application

Purpose and Need

MPUC self-nominated for 2009 rebasing. MPUC will be undergoing substantial increases in its fixed assets over the next five years due to the enhancement and/or replacement of system infrastructure and system expansions. MPUC continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase is attributed to some growth, but is primarily a replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. In 2006 MPUC completed a substation assessment study which provided an analysis of existing infrastructure and a plan for the replacement taking into consideration future growth in our territory. To accommodate these increases MPUC will be seeking additional debt to bring our debt to equity ratio in line with Board approved ratios.

MPUC's forecasts also include increases in OM&A Expenses which reflect increases in employees, regulatory costs and other expenses. OM&A Expenses are expected to increase $384,405 or 22.5% in the 2009 Test Year over 2006 EDR. This increase would reduce to $244,405 or 14.3% if an increase in staffing levels and Rate Application costs were not required. It should be noted that the number of employees in the 2006 EDR, which was based on 2004 actual data totaled 16 and in 2009 MPUC's total compliment will be 16. A complete analysis of this increase is set out in Exhibit 1, Tab 1, Schedule 7 and 9; and Exhibit 4, Tab 2, Schedule 2.

MPUC's revenue requirement for 2009 contemplates the recovery of its costs of providing distribution service; its permitted Return on Equity and the funds necessary to service its debt (based on the OEB's deemed debt/equity rates which is subject to adjustment this year to move it toward the OEB-mandated 60% debt/40% equity) and its Payments in Lieu of Taxes ("PILS"). When its forecasted customers and volumes for 2009 are taken into account, MPUC estimates that its present rates will produce a deficiency in distribution revenue of $897,322 for the 2009 Test Year. Excluded from this estimate is the impact of energy costs, variance/deferral accounts, smart metering and low voltage charges. MPUC therefore seeks the Board's approval to revise its rates applicable to its distribution of electricity. The issues to be reviewed in this case, as MPUC sees them, are discussed below.

Through this Application, MPUC seeks to recover a Base Revenue Requirement of $3,582,721 which includes a Revenue Deficiency in the amount of $897,322 arising from changes in OM&A, Amortization, Rate of Return and PILS. MPUC seeks to recover the balances of Deferral and Variance Accounts in the amount of $171,625 over two years at $85,812 per year. MPUC seeks to recover $1.00 as a rate rider per month per residential and general service customers arising from costs associated with the smart metering infrastructure.

MPUC has been assisted in preparing this application by Elenchus Research Associates (“ERA”) who provided the model used in the determination of just and reasonable 2009 Distribution Rates. MPUC has also been assisted by Bruce Bacon of Borden Ladner Gervais who has reviewed our Application from a technical perspective. MPUC has based this Application on its forecasted results for the 2009 Test Year. As required by the OEB, MPUC is also presenting the historical actual information for fiscal 2006 and 2007; information for the 2008 Bridge Year and 2009 Test Year.

Timing

The financial information supporting the Test Year for this Application will be MPUC’s fiscal year ending December 31, 2009 (the “2009 Test Year”). However, this information will be used to set rates for the period May 1, 2009 to April 30, 2010. The Test Year revenue requirement is that forecast by MPUC as needed to enable it to recover the amounts discussed for fiscal 2009.

Current Rates Schedule

Attached on the pages following this page is the Current Rates Schedule showing Monthly Rates and Charges

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Residential

Service Charge	$	11.3700
Distribution Volumetric Rate	$/kWh	0.0198
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0071
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Less Than 50 kW

Service Charge	$	12.6100
Distribution Volumetric Rate	$/kWh	0.0140
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service 50 to 4,999 kW

Service Charge	$	14.0500
Distribution Volumetric Rate	$/kW	2.3148
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.5532
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Unmetered Scattered Load

Service Charge (per customer)	$	12.3500
Distribution Volumetric Rate	$/kWh	0.0140
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting

Service Charge (per connection)	$	1.4600
Distribution Volumetric Rate	$/kW	2.6254
Retail Transmission Rate – Network Service Rate	$/kW	1.0749
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0150
Wholesale Market Service Rate	$/kWh	0.0052

Sentinel Lighting – Cont'd

Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting

Service Charge (per connection)	$	0.9600
Distribution Volumetric Rate	$/kW	2.3727
Retail Transmission Rate – Network Service Rate	$/kW	1.0694
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges

Customer Administration		
- Notification Charge	$	15.0000
- Account history	$	15.0000
- Returned Cheque charge (plus bank charges)	$	15.0000
- Legal letter charge	$	15.0000
- Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.0000
Non-Payment of Account		
- Late Payment – per month	%	1.5000
- Late Payment - per annum	%	19.5600
- Disconnect/Reconnect at meter – during regular hours	$	65.0000
- Disconnect/Reconnect at meter – after regular hours	$	185.0000
- Disconnect/Reconnect at pole – during regular hours	$	185.0000
- Disconnect/Reconnect at pole – after regular hours	$	415.0000
Specific Charge for Access to Power Poles $/pole/year	$	22.3500
Install/Remove load control device – during regular hours	$	65.0000
Install/Remove load control device – after regular hours	$	185.0000
Temporary service install & remove – overhead – no transformer	$	500.0000
Temporary service install & remove – underground – no transformer	$	300.0000

Allowances

- Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.6000
- Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.0000

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0651
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0545
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rates Schedule

Attached on the pages following this page is the Proposed Rates Schedule showing Monthly Rates and Charges (Effective May 1, 2009).

Residential

Service Charge	$	12.8100
Distribution Volumetric Rate	$/kWh	0.0211
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0071
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service <50 kW

Service Charge	$	16.0900
Distribution Volumetric Rate	$/kWh	0.0171
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service >50 Kw

Service Charge	$	58.9900
Distribution Volumetric Rate	$/kW	4.2097
Regulatory Asset Recovery	$/kW	0.1645
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.5532
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting

Service Charge (per connection)	$	2.7900
Distribution Volumetric Rate	$/kW	6.9080
Regulatory Asset Recovery	$/kW	0.1538
Retail Transmission Rate – Network Service Rate	$/kW	1.0694
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting

Service Charge (per connection)	$	16.2500
Distribution Volumetric Rate	$/kW	29.1889
Regulatory Asset Recovery	$/kW	0.1423
Retail Transmission Rate – Network Service Rate	$/kW	1.0749
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0150
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Unmetered Scattered Load

Service Charge	$	22.3800
Distribution Volumetric Rate	$/kWh	0.0254
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges

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	$	30.00
Late Payment - per month	%	1.50
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50

Specific Service Charges – Cont’d

Interval Meter Load Management Tool	$	25.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0651
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0545

Summary of Bill Impact

Table 1 Residential Bill Impact

Description		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
1,000 kWh	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	1,000	$0.0198	$19.80	1,000	$0.0211	$21.10	$1.30	6.6%
Sub-Total (Distribution)				**$31.17**			**$33.91**	**$2.74**	**8.8%**
Deferral/Variance Dispositions	kWh	1,000			1,000	$0.0004	$0.40	$0.40	
Electricity (Commodity)	kWh	1,065	RPP-Summer	$57.44	1,065	RPP-Summer	$57.44		
Transmission - Network	kWh	1,065	$0.0038	$4.05	1,065	$0.0038	$4.05		
Transmission - Connection	kWh	1,065	$0.0071	$7.56	1,065	$0.0071	$7.56		
Wholesale Market Service	kWh	1,065	$0.0052	$5.54	1,065	$0.0052	$5.54		
Rural Rate Protection	kWh	1,065	$0.0010	$1.07	1,065	$0.0010	$1.07		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$113.83**			**$116.97**	**$3.14**	**2.8%**

MPUC is proposing to increase the fixed monthly charge to $12.81 and the volumetric distribution charge to $0211 per kWh in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $00040 per kWh. MPUC is also proposing to increase the rate rider for smart metering infrastructure to $1.00 per month. This increase is included in the monthly fixed charge. The impact on a residential customer with 1000kWhs is an increase of 8.8% on the distribution portion of the bill and 2.8% on the total bill. The bill impacts on Residential customers are shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the Residential class. A Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at

Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that Residential Customers were contributing 118.18% of revenues. In this Application, MPUC is proposing rates that are fair and balanced to all customers. A total bill impact of 2.8% does not constitute rate shock; hence MPUC is not proposing Rate Mitigation for Residential customers. Our approach is to bring customers into line with the results of the Cost Allocation Study over time.

Table 2 General Service Bill Impact (less than 50kW)

Description		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
2,000 kWh	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	2,000	$0.0140	$28.00	2,000	$0.0171	$34.20	$6.20	22.1%
Sub-Total (Distribution)				**$40.61**			**$50.29**	**$9.68**	**23.8%**
Deferral/Variance Dispositions	kWh	2,000			2,000	$0.0004	$0.80	$0.80	
Electricity (Commodity)	kWh	2,130	RPP-Summer	$120.28	2,130	RPP-Summer	$120.28		
Transmission - Network	kWh	2,130	$0.0034	$7.24	2,130	$0.0034	$7.24		
Transmission - Connection	kWh	2,130	$0.0065	$13.85	2,130	$0.0065	$13.85		
Wholesale Market Service	kWh	2,130	$0.0052	$11.08	2,130	$0.0052	$11.08		
Rural Rate Protection	kWh	2,130	$0.0010	$2.13	2,130	$0.0010	$2.13		
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
TOTAL BILL				**$209.19**			**$219.67**	**$10.48**	**5.0%**

MPUC is proposing to increase the fixed monthly service charge to $16.09 and the volumetric distribution charge to $0.0171 per kWh in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $0.00040 per kWh. MPUC is also proposing to increase the rate rider for smart metering infrastructure to $1.00 per month. This increase is included in the monthly fixed charge. The impact on a general service less than 50kW customer with 2000kWhs is an increase of 23.8% on the distribution portion of the bill and 5.0% on the total bill. The bill impacts on general service <50kW customers are shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate Mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the General Service <50kW. As mentioned previously, a Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that General Service <50kW customers were contributing 97.96% of revenues. In this Application, MPUC is proposing rates that are fair and balanced to all customers. A total bill impact of 5.0% does not constitute rate shock; hence MPUC is not proposing Rate Mitigation for General Service <50kW customers. Our approach is to bring customers into line with the results of the Cost Allocation Study over time.

Table 3 General Service Bill Impact (more than 50kW)

Description		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
750,000kWh 1800kW	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,800	$2.3148	$4,166.64	1,800	$4.2097	$7,577.46	$3,410.82	81.9%
Sub-Total (Distribution)				**$4,180.69**			**$7,636.45**	**$3,455.76**	**82.7%**
Deferral/Variance Dispositions	kW	1,800			1,800	$0.1645	$296.10	$296.10	
Electricity (Commodity)	kWh	798,825	$0.0545	$43,535.96	798,825	$0.0545	$43,535.96		
Transmission - Network	kW	1,800	$1.4180	$2,552.40	1,800	$1.4180	$2,552.40		
Transmission - Connection	kW	1,800	$2.5532	$4,595.76	1,800	$2.5532	$4,595.76		
Wholesale Market Service	kWh	798,825	$0.0052	$4,153.89	798,825	$0.0052	$4,153.89		
Rural Rate Protection	kWh	798,825	$0.0010	$798.83	798,825	$0.0010	$798.83		
Debt Retirement Charge	kWh	750,000	$0.0070	$5,250.00	750,000	$0.0070	$5,250.00		
TOTAL BILL				**$65,067.53**			**$68,819.39**	**$3,751.86**	**5.8%**

In order to increase the fixed cost recovery, MPUC is proposing to increase the monthly fixed charge to $58.99 and in order to increase the variable cost recovery MPUC is proposing to increase the volumetric distribution charge to $4.2097 per kW in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $0.1645 per kW. MPUC is also proposing to increase the rate rider for smart metering infrastructure to $1.00 per month. This increase is included in the monthly fixed charge. The impact on a general service greater than 50kW customer with 750,000 kWh with 1800kW demand is an increase of 82.7% on the distribution portion of the bill and 5.8% on the total bill. The bill impacts on general service >50kW customers are shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate Mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the General Service >50kW. As mentioned previously, a Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that General Service >50kW customers were contributing 83.67% of revenues. In this Application, MPUC is proposing rates that are fair and balanced to all customers. A total bill impact of 5.8% does not constitute rate shock; hence MPUC is not proposing Rate Mitigation for General Service >50kW customers. Our approach will be to bring customers into line with the results of the Cost Allocation Study. General Service>50kW have been subsidized by Residential customers in the past and to continue this practice would not be fair to the Residential customer. MPUC is proposing to bring the General Service >50kW customer revenue to cost ratio to 98% which brings this class closer to paying its fair share of the costs which are attributed to them.

Table 4 Street Lighting Bill Impact

Description		2008 BILL			2009 BILL			CHANGE IMPACT	
59 kWh/.18kW	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.18	$2.3727	$0.42	.18	$6.9080	$1.23	$0.81	>100%
Sub-Total (Distribution)				**$1.38**			**$4.02**	**$2.64**	**>100%**
Deferral/Variance Dispositions	kW	0.18			0.18	$0.1538	$0.03	$0.03	
Electricity (Commodity)	kWh	63.00	RPP-Summer	$3.16	63.00	RPP-Summer	$3.16		
Transmission - Network	kW	0.18	$1.0694	$0.19	0.18	$1.0694	$0.19		
Transmission - Connection	kW	0.18	$1.9738	$0.35	0.18	$1.9738	$0.35		
Wholesale Market Service	kWh	63.00	$0.0052	$0.33	63.00	$0.0052	$0.33		
Rural Rate Protection	kWh	63.00	$0.0010	$0.06	63.00	$0.0010	$0.06		
Debt Retirement Charge	kWh	59.00	$0.0070	$0.42	59.00	$0.0070	$0.42		
TOTAL BILL				**$5.89**			**$8.56**	**$2.67**	**45.3%**

In order to increase the fixed cost recovery, MPUC is proposing to increase the monthly fixed charge to $2.79 and in order to increase the variable cost recovery MPUC is proposing to increase the volumetric distribution charge to $6.9080 per kW in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $.1538 per kW. The impact on a street light customer with one connection at 59 kWh with .18kW demand is an increase of greater than 100% on the distribution portion of the bill and 45.3% on the total bill. The bill impacts on a street light customer are shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate Mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the Street Lighting class. As mentioned previously, a Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that Street Light customers were contributing 23.46% of revenues. In this Application, MPUC is proposing rates that are fair and balanced to all customers. Although the total bill impact of 45.3% is significant, this increase is necessary bring customers into line with the results of the Cost Allocation Study. Street Light customers have been subsidized by Residential customers in the past and to continue this practice would not be fair to the Residential customer. MPUC is proposing to bring the Street Light customer revenue to cost ratio to 49%, which brings this class closer to paying its fair share of the costs which are attributed to them.

Table 5 Sentinel Lighting Bill Impact

Description		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
15,000 kWh/10kW	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	10	$2.6254	$26.25	10	$29.1889	$291.89	$265.64	>100%
Sub-Total (Distribution)				**$27.71**			**$308.14**	**$280.43**	**>100%**
Deferral/Variance Dispositions	kW	10			10	$0.1423	$1.42	$1.42	
Electricity (Commodity)	kWh	15,977	RPP-Summer	$937.21	15,977	RPP-Summer	$937.21		
Transmission - Network	kW	10	$1.0749	$10.75	10	$1.0749	$10.75		
Transmission - Connection	kW	10	$2.0150	$20.15	10	$2.0150	$20.15		
Wholesale Market Service	kWh	15,977	$0.0052	$83.08	15,977	$0.0052	$83.08		
Rural Rate Protection	kWh	15,977	$0.0010	$15.98	15,977	$0.0010	$15.98		
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,199.88**			**$1,481.73**	**$281.85**	**23.5%**

In order to increase the fixed cost recovery, MPUC is proposing to increase the monthly fixed charge to $16.25 and in order to increase the variable cost recovery MPUC is proposing to increase the volumetric distribution charge to $29.1889 per kW in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $0.1423 per kW. The impact on a sentinel light customer with one connection at 15,000 kWh with 10 kW demand is an increase of greater than 100% on the distribution portion of the bill and 23.5% on the total bill. The bill impact on sentinel light customers are shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate Mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the Sentinel Lighting class. As mentioned previously, a Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that Sentinel Light customers were contributing 28.21% of revenues. In this Application, MPUC is proposing rates that are fair and balanced to all customers. Although the total bill impact of 23.5% is significant, this increase is necessary to bring Sentinel Light customers into line with the results of the Cost Allocation Study. Sentinel Lighting customers have been subsidized by Residential customers in the past and to continue this practice would not be fair to the Residential customer. MPUC is proposing to bring the Sentinel Light customer revenue to cost ratio to 49%, which brings this class closer to paying its fair share of the costs which are attributed to them.

Table 6 Unmetered Scattered Load Bill Impact

Description		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
15,000 kWh	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	15,000	$0.0140	$210.00	15,000	$0.0254	$381.00	$171.00	81.4%
Sub-Total (Distribution)				**$222.35**			**$403.38**	**$181.03**	**81.4%**
Deferral/Variance Dispositions	kWh	15,000			15,000	$0.0004	$6.00	$6.00	
Electricity (Commodity)	kWh	15,977	RPP-Summer	$937.21	15,977	RPP-Summer	$937.21		
Transmission - Network	kWh	15,977	$0.0034	$54.32	15,977	$0.0034	$54.32		
Transmission - Connection	kWh	15,977	$0.0065	$103.85	15,977	$0.0065	$103.85		
Wholesale Market Service	kWh	15,977	$0.0052	$83.08	15,977	$0.0052	$83.08		
Rural Rate Protection	kWh	15,977	$0.0010	$15.98	15,977	$0.0010	$15.98		
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,521.79**			**$1,708.82**	**$187.03**	**12.3%**

In order to increase the fixed cost recovery, MPUC is proposing to increase the monthly fixed charge to $22.38 and in order to increase the variable cost recovery MPUC is proposing to increase the volumetric distribution charge to $0.0254 per kWh in the 2009 Test Year and to include a Deferral/Variance Account Rate Rider of $.0004 per kWh. The impact on an unmetered scattered load customer at 15,000 kWh is an increase of 81.4% on the distribution portion of the bill and 12.3% on the total bill. The bill impacts on unmetered scattered load customers are is shown in detail in Exhibit 9, Tab 1, Schedule 9.

Rate Mitigation is discussed at Exhibit 9, Tab 1, Schedule 4. MPUC is not proposing rate mitigation for the Unmetered Scattered Load class. As mentioned previously, a Cost Allocation Study was filed with the Ontario Energy Board as an informational filing in 2007. A copy of this Study is included in this Application at Exhibit 8. Cost Allocation Revenue to Cost Ratios are discussed at Exhibit 8, Tab 1, Schedule 2. These ratios revealed that Unmetered Scattered Load customers were contributing 117.38% of revenues, the result being that this class is subsidizing other classes. In this Application, MPUC is proposing rates that are fair and balanced to all customers. The proposed increase will bring USL customers into line with the results of the Cost Allocation Study. MPUC is proposing to bring the Unmetered Scattered Load customer revenue to cost ratio to 100%, which brings this class equal to paying its fair share of the costs which are attributed to them.

MPUC therefore considers its proposed rates to have acceptable impacts on the customers' bills and therefore is not proposing any rate mitigation measures.

List of Issues

There are a number of issues that, although they may not all be defined as major, are anticipated to be examined in this case. These issues are listed below:

Capital Structure

MPUC's current deemed capital structure is 53.3% debt/46.7% equity. In its December 20, 2006 Report on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors, the OEB mandated a shift to a 60% debt/40% equity ratio for all distributors. Consequently, MPUC is requesting a change in its deemed capital structure. Specifically, MPUC is requesting a decrease in the deemed equity ratio from 46.7% to 43.3% and increase the debt ratio from 53.3% to 56.7% consistent with the 3 year phase-in of MPUC's capital structure from 50% to 40% equity.

Return on Equity

In addition, MPUC has assumed a return on equity of 8.57% consistent with the rate of return on equity approved by the OEB for 2008 cost of service applications. MPUC understands the OEB will be finalizing the return on equity for 2009 rates based on January 2009 market interest rate information.

Capital Expenditures

MPUC continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase is attributed to some growth, but is primarily a replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. In 2006 MPUC completed a substation assessment study which provided an analysis of infrastructure and a plan for the replacement taking into consideration future growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old. This study has provided MPUC with a comprehensive list of specifications and analysis to enable MPUC to plan for the replacement of the infrastructure.

Operating and Maintenance Costs

Operating and maintenance costs have been updated to reflect the impact of inflation and expected changes in costs and as a result of increased labour compliment and regulatory requirements. The following table shows that the increase in OM&A expenses over the 2006 EDR is $384,405 in the 2009 test year.

Table 7 Increase in OM&A Expenses (2009 vs 2006)

Year	Amount
2009 Test Year	$2,093,100
2006 EDR	$1,708,695
Increase in OM&A	$ 384,405
Percentage Increase	22.5%

The 2006 EDR OM&A is based on 2004 actual expenses. The increase of 22.5% therefore represents an increase of 4.5% per year from 2004 to 2009. Included in this increase are new costs in 2009. A new management position has been created in mid 2008 in response to the increased regulatory and safety requirements. In addition, regulatory costs associated with this Rate Application have increased substantially over 2008 levels. An analysis of this need is more particularly set out in Exhibit 1, Tab 1, Schedule 9 and Exhibit 4, Tab 2, Schedule 2.

If the management position and regulatory costs were not required, MPUC's increase over the 2006 EDR would be $244,405 or 14.3%, as shown in the table below:

Table 8 Increase in OM&A Expenses without Specific Costs

Description	Amount
OM&A increase over 2006 EDR	$384,405
Less: 2009 Regulatory Costs	$ 50,000
Less: New Staff	$ 90,000
Net OM&A increase over 2006 EDR	$244,405
Percentage Increase	14.3%

As indicated above, the 2006 EDR is based on 2004 OM&A expenses. The increase of 14.3% therefore represents an increase of 2.9% per year.

Smart Meter Infrastructure

MPUC is a member of the CHEC group – Cornerstone Hydro Electric Concepts Inc., a group of 17 LDCs in the Province of Ontario who have worked together over the last ten years to gain economies and efficiencies in both regulatory and industry initiatives. One of these initiatives is the Smart Metering Infrastructure. MPUC, along with other members of the CHEC group, have met with the Ministry of Energy staff to arrange approval to begin installation of smart meters in our service territory in order to meet the Government's 2010 timeline. MPUC is requesting a rate rider for smart metering infrastructure in the 2009 Rate Application.

Bad Debts

In 2006 and 2007 MPUC had two General Service Customers declare bankruptcy. MPUC followed the OEB regulatory requirements in dealing with these customers. MPUC was not been able to collect deposits from these customers prior to their bankruptcy as both customers had excellent payment history and were grandfathered into the new rules at the time of incorporation of MPUC. MPUC has therefore set its bad debt expense at $80,000 per year. Since market opening the provincial and local economic performance has been generally robust; however, MPUC is now seeing evidence of a business downturn consistent with the economic conditions for Ontario that are being widely reported in the press. MPUC feels that other businesses in its service territory may be at risk as manufacturers struggle with the economy. In order to mitigate these risks MPUC is diligent in ensuring prompt payment, however, should a customer declare bankruptcy or file for protection, MPUC has already suffered sufficient losses in that our billing process is already up to 6 weeks behind the day of consumption. The following is a schedule outlining the bad debt balances from 2003 to 2007:

Table 9 Bad Debts and Allowance for Doubtful Accounts (2003 to 2007)

	2003	2004	2005	2006	2007
Bad Debts – Income Statement	$28,281	$31,942	$63,312	$78,167	$130,344
Allowance For Doubtful Accounts – Balance Sheet	$76,272	$77,241	$40,000	$80,000	$80,000

In the alternative, MPUC requests that the distribution revenues only form a part of the bad debts and the balance of the receivable be allocated to the associated cost of power charges.

Posting Errors

In preparing this application we have undertaken a thorough review and examination of all APH USoA and have found posting errors in expense accounts and in capital accounts. We have taken steps in the application to report the allocation errors and have provided the correct account listings where expenses or capital should be posted. These postings have had no impact on Capital or OM&A Expenses as the misallocations were between capital accounts **or** expense accounts and were not between capital **and** expense accounts, except for the following:

Merchandising/Jobbing

In 2004, Revenue from Merchandising/Jobbing with respect to contributed capital projects was recorded as income. Expenses related with these jobs were deducted from the revenue. In doing so, capital asset balances and contributed capital were understated, and income was overstated. In 2004, the income was deducted from distribution expenses resulting in an understatement of the Revenue Requirement for the 2006 EDR. The recording of contributed capital work was corrected going forward in 2005.

Transmission Rates

MPUC has not made any change to its retail transmission rates in this Application. MPUC is aware that Hydro One has made application to the Ontario Energy Board on May 30, 2008 to adjust uniform transmission rates effective January 1, 2009 under Board File number EB-2008-0113. Once an Order has been made by the Ontario Energy Board, MPUC will make the appropriate adjustments to its transmission rates in this Application.

List of Specific Approvals Requested

MPUC requests the following specific approvals:

1. Approval to charge rates effective May 1, 2009 to recover a revenue requirement of $3,582,721.

2. Approval of our Monthly Rates and Specific Service charges listed in Exhibit 1, Tab 1, Schedule 5.

3. Approval of MPUC's proposed change in capital structure involving the decrease of the deemed common equity component from 46.7% to 43.3% and increase the debt component from 53.3% to 56.7% (Exhibit 6), consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

4. Approval for disposition of Deferral/Variance Account Balances as of December 31, 2007 in the amount of $171,625 over two years - $85,812 per year.

5. Approval to recover $1.00 as a rate rider per month per meter per residential and general service customers arising from costs associated with the smart metering infrastructure.

6. Approval to recover $339,515 in low voltage charges.

Schedule of Overall Revenue Deficiency/Sufficiency

Table 10 Summary of Revenue Deficiency/Sufficiency – 2009 Projection

Utility Income *(see below)*	88,005
Utility Rate Base	12,318,654
Indicated Rate of Return	0.71%
Requested / Approved Rate of Return	6.33%
Sufficiency / (Deficiency) in Return	(5.62%)
Net Revenue Sufficiency / (Deficiency)	**(692,329)**
Provision for PILs/Taxes	(204,993)
Gross Revenue Sufficiency / (Deficiency)	**(897,322)**
Deemed Overall Debt Rate	*4.64%*
Deemed Cost of Debt	*322,861*
Utility Income less Deemed Cost of Debt	*-234,855*
Return On Deemed Equity	*(4.40%)*

UTILITY INCOME

Total Net Revenues	2,916,530
OM&A Expenses	2,058,900
Depreciation & Amortization	735,424
Taxes other than PILs / Income Taxes	34,200
Total Costs & Expenses	2,828,524
Utility Income before Income Taxes / PILs	88,005
PILs / Income Taxes	
Utility Income	**88,005**

Causes of the Deficiency/Sufficiency

With existing rates MPUC will not be able to achieve an 8.57% rate of return on equity resulting from higher capital and OM&A expenses in 2009. Operating and maintenance costs have increased reflecting the impact of inflation and expected changes in costs and as a result of increased labour compliment and regulatory and safety requirements. These regulatory and safety requirements are changing the way MPUC does business. The increase in management staffing levels recognizes that MPUC is responding to the regulatory and safety needs by moving towards increasing and improving business practices and processes. These improvements and upgrades to business practices will pay benefits in the long run. Consequently, these increased requirements for regulatory oversight and safety legislation will require increased costs. MPUC will be undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. The management position will play an important role in the design and implementation of these replacements/enhancements.

MPUC continues to enhance and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase is attributed to some growth, but is primarily a replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. In 2006 MPUC completed a substation assessment study which provided an analysis of existing infrastructure and a plan for the replacement taking into consideration future growth in our territory. This study has provided MPUC with a plan which will see the substations replaced over a number of years. In 2007 the first substation, Scott Street was replaced, Brandon will follow in 2008 and Fourth Street in 2009.

MPUC’s return on capital in the 2009 Test Year at existing rates is -$692,329. This indicates that MPUC will not earn its regulated return in 2009 based on 2008 Board Approved Rates.

MPUC PILS in the 2009 Test Year is expected to be -$204,993 which is relative to the projected amount to be collected based on the proposed rates in the 2009 Test Year. This amount coupled with the Net Revenue Deficiency of $692,329 provides for the Gross Revenue Deficiency of $897,322 as indicated on the Revenue Sufficiency/Deficiency Summary.

Board Findings and Directions from 2007 EDR

There are no Board Findings and Directions from the 2007 EDR active for MPUC.

Board Findings and Directions from 2006 EDR

There are no Board Findings and Directions from the 2006 EDR active for MPUC.

Status of Board Directives

Not Applicable.

Company Overview

Utility Description

COMMUNITY SERVED:	Town of Midland
TOTAL SERVICE AREA:	20 sq. km.
RURAL SERVICE AREA:	none
DISTRIBUTION TYPE:	Electricity
SERVICE AREA POPULATION:	16000
MUNICIPAL POPULATION:	17000

BOUNDARIES: The distribution service area within the Town of Midland is confined with the legal boundary limits of the Town of Midland except as described below:

The parcel of land surrounded by the northern Town boundary and the centerline of the roads, beginning at a point on Old Penetanguishene Road southerly to a point at Harbourview Drive (if extended), easterly along Harbourview to Fuller Street, then northerly along Fuller Street to Gawley Drive, then easterly along Gawley Drive to the shoreline of Georgian Bay.

The parcel of land described above laying east of Fuller Street was formerly known as Sunnyside and the parcel of land described above laying west of Fuller Street was formerly known as Portage Park.

Overview

MPUC is the electricity distributor licenced by the Ontario Energy Board to serve the Town of Midland as described above. MPUC was incorporated under the Business Corporations Act (Ontario) on December 22, 1999. The sole shareholder of MPUC is The Corporation of the Town of Midland. All of MPUC's debt is held by The Corporation of the Town of Midland.

MPUC operates an electrical distribution system with a total service area of 20 square kilometers within the Town of Midland. MPUC delivers electricity through a network of overhead and underground wires, through transformer stations to approximately 6700 customers in residential, general service classes. MPUC's annual revenue inclusive of electricity commodity revenue in 2007 was $19,622,987. MPUC employs a full-time workforce of 15 skilled employees who are dedicated to delivering a safe and reliable supply of electricity to customers

Contact Information

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L4R 4P4

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Chief Financial Officer
Midland Power Utility Corporation
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P.O Box 820
Midland, Ontario
L4R 4P4

Email: cbell@midlandpuc.onca
Telephone: 705-526-9362 ext 219
Fax: 705-526-7890

Neighbouring Utilities

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

Barrie Hydro Distribution Inc.
55 Patterson Road
Box 700
Barrie, Ontario
L4M 4V8

Attention: Ms. Barb Gray, Manager of Corporate Services & Regulatory Affairs

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

Attention: Paul Ferguson, President

Host or Embedded Utilities

MPUC does not host any utilities within its service area.

MPUC does not have any embedded utilities within its service area.

MPUC is an embedded distributor within Hydro One's service territory. MPUC is a registered Market Participant dealing directly with the IESO and has one metering point that is metered by Hydro One. Consequently, MPUC 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, MPUC is billed monthly by Hydro One for Transmission and Low Voltage Charges.

LDC's Distribution License

A copy of the Distribution Licence for MPUC is attached on the next pages.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0204
EB-2002-0541 1

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an application by Midland Power Utility Corporation for renewal of its electricity distribution licence. 3

By delegation, before: Mark C. Garner 4

DECISION AND ORDER 5

Midland Power Utility Corporation (the "Applicant") filed an application dated December 17, 2002 with the Ontario Energy Board under section 60 of the *Ontario Energy Board Act, 1998*, c. 15, Schedule B (the "Act") for renewal of its electricity distribution licence. 6

The Board's Notice of Application and Notice of Proposal for renewal of its electricity distribution licence was published on November 4, 2003. Hydro One Networks ("Networks") provided a written submission in response to the Notice. 7

Consideration has been given to the application and the written submission by Networks regarding the definition of the Applicant's service area. After considering the application, I find that it is in the public interest to issue the electricity distribution licence under Part V of the Act. 8

IT IS THEREFORE ORDERED THAT: 9

The application by Midland Power Utility Corporation to renew its electricity distribution licence is granted, on such conditions as are contained in the licence [oeb:12Y8R-0:1]. 10

DATED at Toronto, November 26, 2003.

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Secretary

Electricity Distribution Licence

ED-2002-0541

Midland Power Utility Corporation

Valid Until
November 25, 2023

Mark C. Garner
Secretary
Ontario Energy Board

Date of Issuance: November 26, 2003

Ontario Energy Board	Commission de l'Énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
26th. Floor	26e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

1 Definitions 1

In this Licence: 2

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee; 3

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B; 4

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies; 5

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order; 6

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems; 7

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A; 8

"**Licensee**" means: Midland Power Utility Corporation; 9

"**Market Rules**" means the rules made under section 32 of the Electricity Act; 10

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act; 11

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge; 12

"**regulation**" means a regulation made under the Act or the Electricity Act; 13

"Retail Settlement Code" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 14

"service area" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 15

"Standard Supply Service Code" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act; 16

"wholesaler" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 17

2 Interpretation 18

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day. 19

3 Authorization 20

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence: 21

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; 22

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and 23

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act. 24

4 Obligation to Comply with Legislation, Regulations and Market Rules 25

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts except where the Licensee has been exempted from such compliance by regulation. 26

4.2 The Licensee shall comply with all applicable Market Rules. 27

5 Obligation to Comply with Codes 28

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence: 29

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 30

b) the Distribution System Code; 31

c) the Retail Settlement Code; and 32

d) the Standard Supply Service Code. 33

5.2 The Licensee shall: 34

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and 35

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 36

6 Obligation to Provide Non-discriminatory Access 37

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence. 38

7 Obligation to Connect 39

7.1 The Licensee shall connect a building to its distribution system if: 40

a) the building lies along any of the lines of the distributor's distribution system; and 41

b) the owner, occupant or other person in charge of the building requests the connection in writing. 42

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 43

a) the building is within the Licensee's service area as described in Schedule 1; and 44

b) the owner, occupant or other person in charge of the building requests the connection in writing. 45

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board. 46

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 47

8 Obligation to Sell Electricity 48

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board. 49

9 Obligation to Maintain System Integrity 50

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board. 51

10 Market Power Mitigation Rebates 52

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 53

11 Distribution Rates 54

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board. 55

12 Separation of Business Activities 56

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 57

13 Expansion of Distribution System 58

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 59

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 60

14 Provision of Information to the Board 61

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time. 62

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs. 63

15 Restrictions on Provision of Information 64

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. 65

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed: 66

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 67

b) for billing, settlement or market operations purposes; 68

c) for law enforcement purposes; or 69

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 70

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 71

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent. 72

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed. 73

16 Customer Complaint and Dispute Resolution 74

16.1 The Licensee shall: 75

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner; 76

b) publish information which will make its customers aware of and help them to use its dispute resolution process; 77

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; 78

d) give or send free of charge a copy of the process to any person who reasonably requests it; and 79

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective. 80

17 Term of Licence 81

17.1 This Licence shall take effect on November 26, 2003 and expire on November 25, 2023. The term of this Licence may be extended by the Board. 82

18 Fees and Assessments 83

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 84

19 Communication 85

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change. 86

19.2 All official communication relating to this Licence shall be in writing. 87

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 88

a) when delivered in person to the addressee by hand, by registered mail or by courier; 89

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and 90

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 91

20 Copies of the Licence 92

20.1 The Licensee shall: 93

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and 94

b) provide a copy of the Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies. 95

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 96

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8.1 of this Licence. 97

The Town of Midland as of December 31, 1997. 98

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 100

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act. 101

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 102

SCHEDULE 3 LIST OF CODE EXEMPTIONS 103

This Schedule specifies any specific Code requirements from which the Licensee has been exempted. 104

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it. 105

APPENDIX A MARKET POWER MITIGATION REBATES 106

1 Definitions and Interpretation 107

In this Licence, 108

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity; 109

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates; 110

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant. 111

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments made by the IMO. 112

2 Information Given to IMO 113

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to: 114

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 115

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 116

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to: 117

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 118

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. 119

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 120

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment. 121

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period. 122

3 Pass Through of Rebate 123

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 124

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented; 125

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 126

c embedded distributors to whom the distributor distributes electricity. 127

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor. 128

129

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

130

"ONTARIO POWER GENERATION INC. rebate"

131

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

132

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

133

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0110

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

AND IN THE MATTER OF a directive approved by the Lieutenant Governor in Council on May 17, 2006, issued by the Minister of Energy to the Ontario Energy Board, pursuant to section 28.1 of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF a proceeding under section 74 of the *Ontario Energy Board Act, 1998* amending certain licences.

BEFORE: Bill Rupert
Presiding Member

Pamela Nowina
Member and Vice Chair

DECISION AND ORDER

Under section 28 of the *Ontario Energy Board Act, 1998* (the "Act"), the Minister of Energy (the "Minister") may, with the approval of the Lieutenant Governor in Council, issue directives with respect to licence conditions to address issues which arise from the market share which Ontario Power Generation Inc. ("OPG") has in the Ontario electricity industry.

The Minister, with the approval of the Lieutenant Governor in Council, issued such directives on March 24, 1999 (OIC No. 600/99). Section 28.1 of the Act authorizes the Minister with the approval of the Lieutenant Governor in Council, to issue directives amending the directive of March 24, 1999 (OIC No. 600/99). Other such directives were issued on March 19, 2003 (OIC No. 654/2003), April 2, 3003 (OIC No. 843/2003), February 16, 2005 (OIC No. 207/2005), December 7, 2005 (OIC No. 600/99) and February 3, 2006 (OIC No. 141/2006).

On May 17, 2006, the Minister of Energy issued a directive (OIC No. 1062/2006), that was approved by the Lieutenant Governor in Council, to the Ontario Energy Board pursuant to section 28.1 of the Act. The directive is related to the adoption of additional terms and conditions of the settlement agreement between OPG and the Independent Electricity System Operator ("IESO") in relation to the OPG Rebate. Accordingly, Schedule 2 attached to OIC No. 141/2006 is revoked and is replaced with a new Schedule B attached to OIC No. 1062/2006. OPG's generation licence is to be amended accordingly. The Board is further directed to amend the licence conditions of the IESO, the Ontario Power Authority, distributors and retailers in a manner consistent with OIC No. 1062/2006 and Schedule B attached thereto.

Based on the wording of Schedule B attached to OIC 1062/2006, distributors will no longer pass through the rebate to retailers from May 1, 2006 onwards for retail customers on the Regulated Price Plan ("RPP") even if the rebate was assigned to the retailer. However, distributors still have to pass through the rebate to retailers for retail customers who are not on the RPP and for retailers who have implemented retailer-consolidated billing. Accordingly, the Board has made modifications to the licences of the distributors and retailers.

Section 28.1 of the Act states that the Board shall amend the licence conditions as required by a directive made under that section without holding a hearing.

THE BOARD THEREFORE ORDERS THAT:

1. Schedule B of the generation licence of OPG (EG-2003-0104) and Schedule B of the licence of the IESO (EI-2003-0088) are revoked and replaced with the document attached as Schedule B to OIC No. 1062/2006.
2. Appendix A of all distributors' licences is amended as set out in Appendix 1 of this Order;
3. Appendix A of all retailers' licences is amended as set out in Appendix 2 of this Order.

DATED at Toronto, September 12, 2006.

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix 1

Appendix A of Distributors' Licences

EB-2006-0110

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Appendix 2

Appendix A of Retailers' licences

EB-2006-0110

APPENDIX A

MARKET POWER MITIGATION REBATES

"OPGI" means Ontario Power Generation Inc.

A retailer shall promptly pass through a portion of the rebate received from a distributor to those consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are served by the retailer but who have not assigned the benefit of the rebate payment to the retailer.

If requested in writing by OPGI, the retailer shall ensure that all rebates paid to consumers are identified as coming from OPGI in the following form on or with each bill or cheque.

"ONTARIO POWER GENERATION INC. rebate"

A retailer shall promptly return to a distributor any portion of the rebate received from the distributor which relates to low-volume or designated consumers receiving the fixed commodity price for electricity under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*, who are served by the retailer but who have not assigned the benefit of the rebate payment to the retailer or another party.

The amounts paid out to consumers or returned to the distributor shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code.

Amounts payable by the retailer may be made by way of set off at the discretion of the retailer.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

A retailer shall promptly pass through a portion of the rebate received from a distributor to those consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are served by the retailer but who have not assigned the benefit of the rebate payment to the retailer.

If requested in writing by OPGI, the retailer shall ensure that all rebates paid to consumers are identified as coming from OPGI in the following form on or with each bill or cheque.

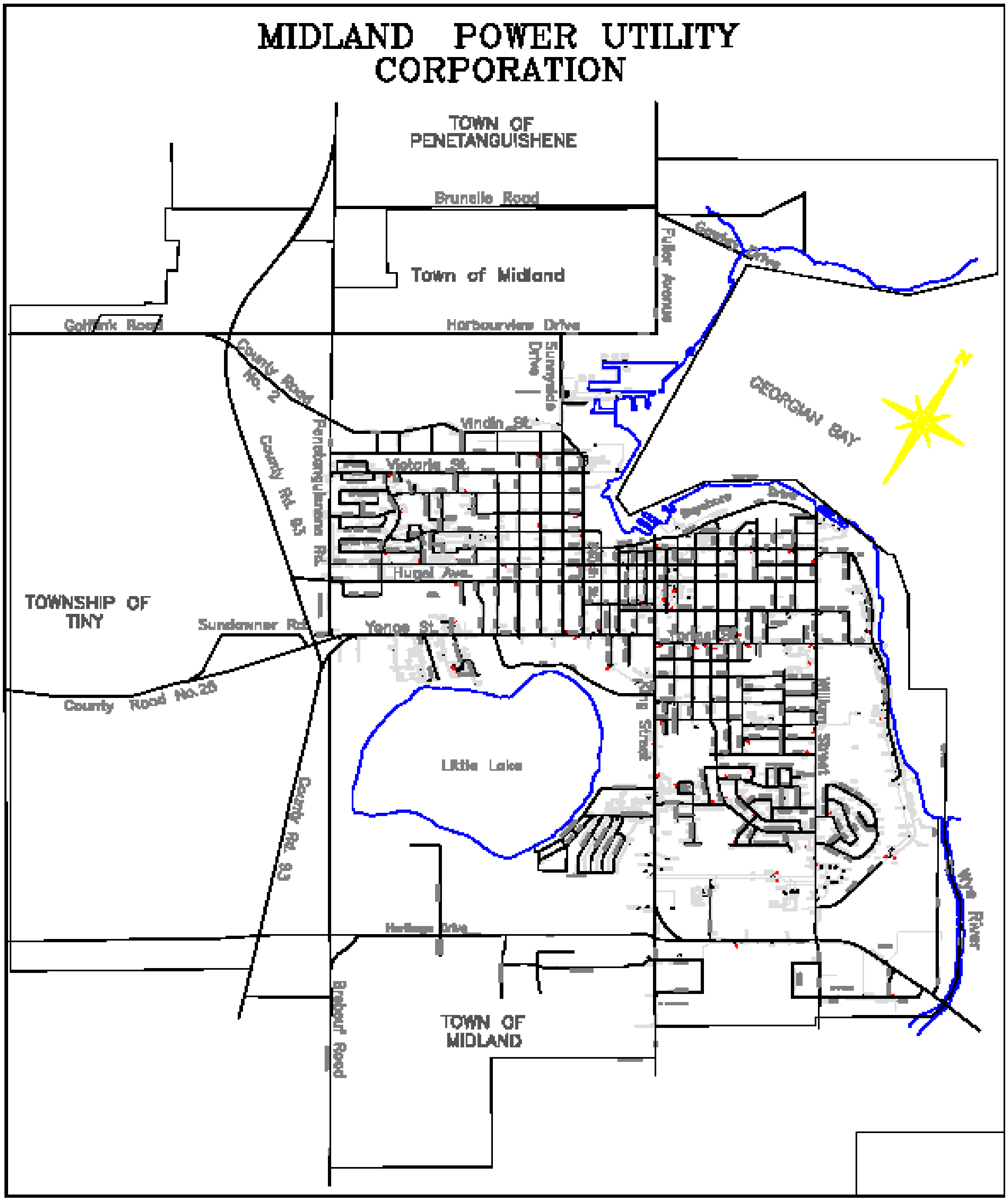
"ONTARIO POWER GENERATION INC. rebate"

The amounts paid out to consumers or returned to the distributor shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code.

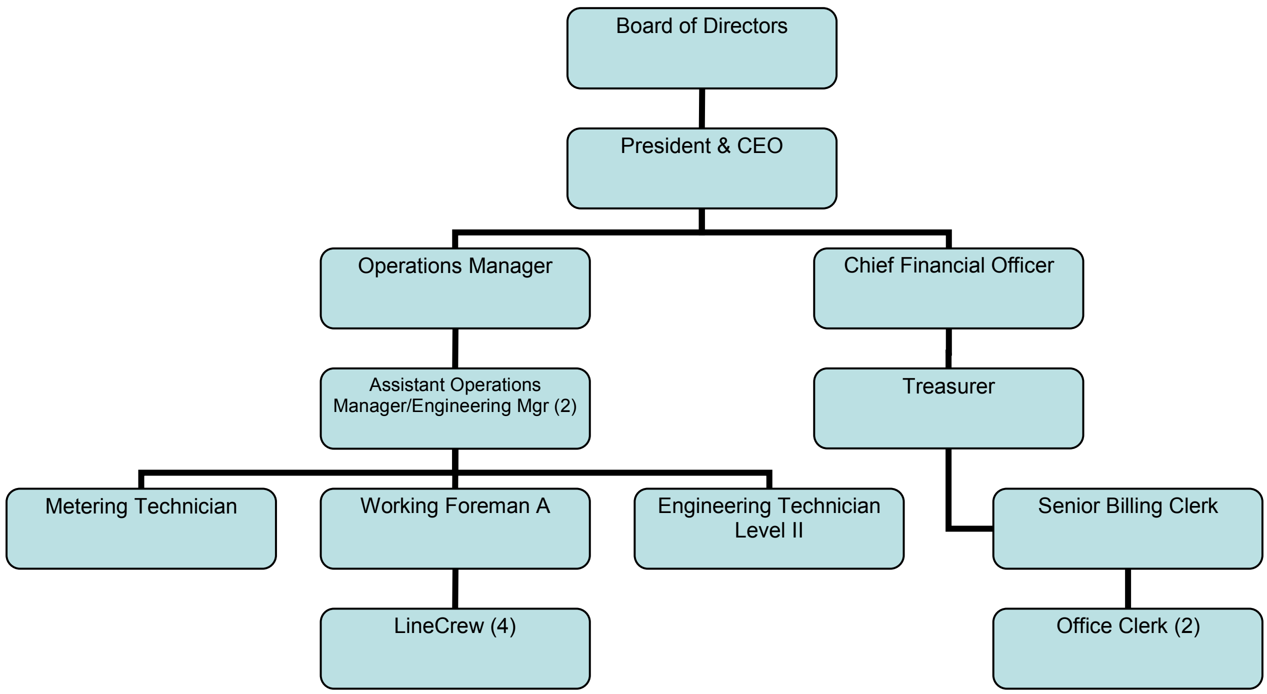
Amounts payable by the retailer may be made by way of set off at the discretion of the retailer.

Map of LDC's Distribution System

A copy of MPUC's distribution system map is set out on the next page.


MIDLAND POWER UTILITY CORPORATION
TOWN OF PENETANGUISHENE
Brunelle Road
Town of Midland
Harbourview Drive
Fuller Avenue
GEORGIAN BAY
County Road No. 2
County Rd. 93
Penetanguishene Rd.
Vindin St.
Victoria St.
Hugel Ave.
Yonge St.
TOWNSHIP OF TINY
Sundowner Rd.
County Road No.25
Little Lake
William Street
Wye River
Heritage Drive
Brebeuf Road
TOWN OF MIDLAND

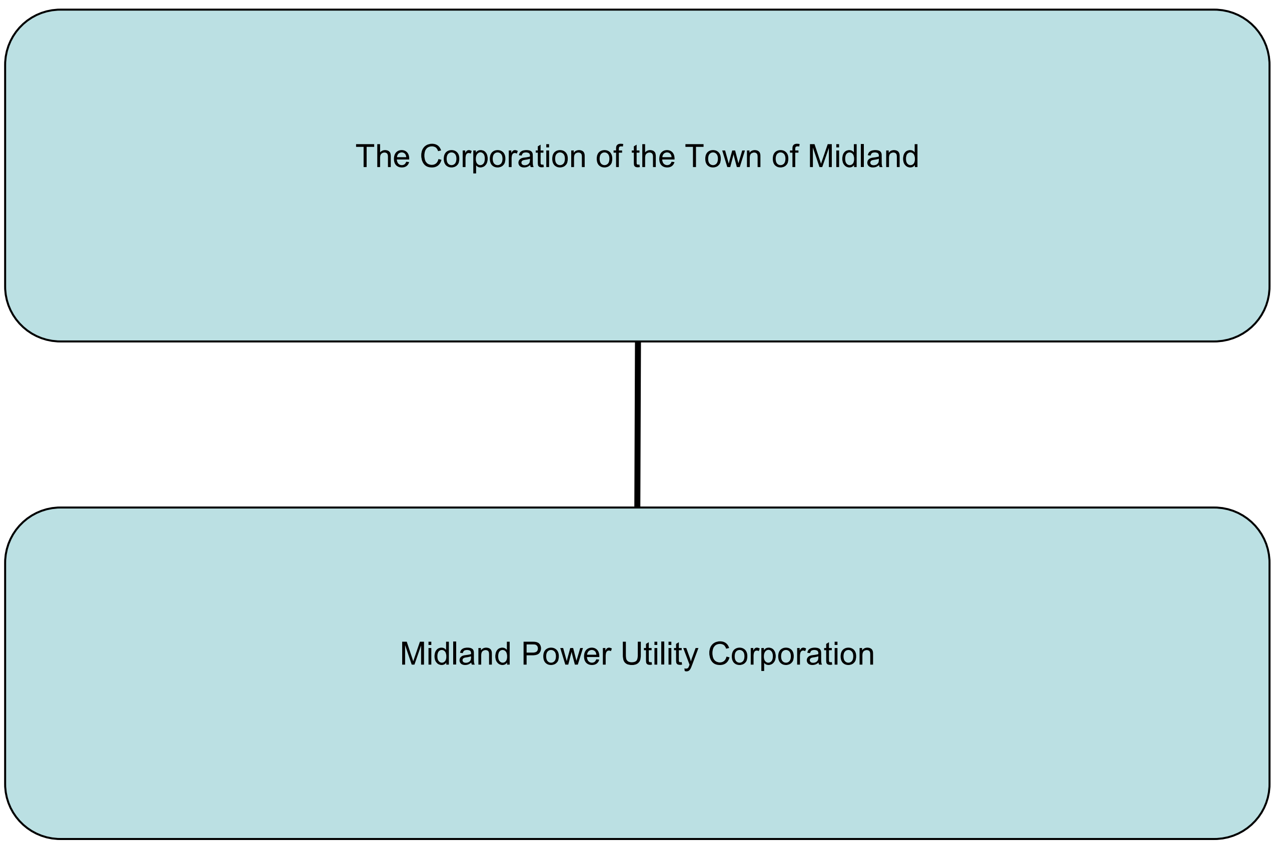
Utility Organizational Chart



MPUC is made up of a five member Board of Directors, two of which are Municipal Councillors.

Corporate Entities Relationships Chart

The Corporation of the Town of Midland is the 100% Shareholder of MPUC. MPUC has no affiliate corporations other than the Corporation of the Town of Midland.



Planned Changes in Corporate or Operational Structure

MPUC does not have any planned changes in corporate and operational structure at the present time.

Conditions of Service/Service Charges

The preparation of the Conditions of Service ("COS") was a joint effort of the CHEC group, one of the many initiatives that the group works collaboratively on to seek cost savings and other efficient synergies. The original COS document was filed with the Board on May 1, 2003, and an updated version of the document was filed on August 1, 2008.

A copy of the most recent version is attached on the pages following this page.

MIDLAND POWER UTILITY CORPORATION

CONDITIONS OF SERVICE

A Proud Member of Cornerstone Hydro Electric Concepts Association Inc.

CornerstonE
Hydro Electric Concepts

CONDITIONS OF SERVICE

Table of Contents

SECTION 1 INTRODUCTION

1.1 Identification of Distributor and Territory

The Distributor is a corporation, incorporated under the laws of the Province of Ontario to distribute electricity.

The Distributor is licensed by the Ontario Energy Board "OEB" to supply electricity to Customers as described in the Transitional Distribution License and thereafter by the Distribution License issued to the Distributor by the OEB. Additionally there are requirements imposed on the Distributor by the various codes referred to in the License and by the Electricity Act and the Ontario Energy Board Act.

The Distributor is limited to operate distribution facilities within their Licensed Territory as defined in the Distribution License.

1.1.1 General

Nothing contained in this document or in any contract for the supply of electricity by the Distributor shall prejudice or affect any rights, privileges, or powers vested in the Distributor by law under any Act of the Legislature of Ontario or the Parliament of Canada, or any regulations thereunder.

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

The Distributor will normally provide one electrical service to each customer location at a nominal service voltage.

Modifications to an existing service must comply with the requirements of the standards in effect at the time of the modifications.

The customer or their authorized representative must make application for new or upgraded electric services and temporary power services.

The customer or their representative shall consult with the Distributor concerning the availability of supply, the voltage of supply, service location, metering and any other details. These requirements are separate from and in addition to those of the Electrical Inspection Authority. The Distributor will confirm, in writing, the Characteristics of Electric Supply available at a specific site.

The customer is required to provide the Distributor sufficient lead-time in order to ensure:

(a) the timely provision of supply to new and upgraded premises or
(b) the availability of adequate capacity for additional loads to be connected in existing premises.

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. The customer will be notified of any extended lead times.

Customers will be required to pay the cost of repair or replacement of the Distributors' equipment that has been damaged through the customers' action or neglect.

The supply of electricity is conditional upon the Distributor being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should the Distributor not be permitted to supply or not be able to do so, it is under no responsibility to the customer whatsoever.

The customer shall not build, plant or maintain or cause to be built, planted or maintained any structure, tree, shrub or landscaping that would or could obstruct the running of distribution lines, endanger the equipment of the Distributor, interfere with the proper and safe operation of the Distributor's facilities or adversely affect compliance with any applicable legislation in the sole opinion of the Distributor.

Prior to commencing any service work, the customer must consult with the Distributor to ensure compliance with current requirements.

The customer is responsible for selecting a qualified/competent contractor. Careful selection of a contractor can significantly affect the cost of a project. The Distributor shall be consulted prior to the selection of a mutually acceptable contractor.

The customer maintains the responsibility to ensure that all work is done in accordance with the distributor's design and technical standards and specifications.

The Distributor, at the expense of the customer, reserves the right to inspect the work throughout the duration of the project, and the Contractor shall supply him such accommodations as he may require. The Inspector shall request that the Contractor stop work at any time he feels the Contractor is not proceeding in accordance with these "conditions of service". The customer shall confer with the Distributor before work recommences to mitigate undue cost and construction delays for the project.

Customers may be required to pay Capital Contributions for the addition of new and upgraded electrical services in accordance with the Economic Evaluation process as defined in the Distribution System Code.

1.2 Related Codes and Governing Laws

The Distributor is limited in its scope of operation by the:

1. *Electricity Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm
2. *Ontario Energy Board Act, 1998*
   www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm

3. *Distribution Licence*
   Licence Numbers
4. *Affiliate Relationships Code*
   http://www.collus.com/images/stories/Documents/ARC.pdf
5. *Distribution System Code*
   http://www.collus.com/images/stories/Documents/DSC.pdf
6. *Retail Settlements Code*
   http://www.collus.com/images/stories/Documents/RSC.pdf
7. *Standard Service Supply Code*
   http://www.collus.com/images/stories/Documents/SSSC.pdf
8. *Transmission System Code*
   http://www.collus.com/images/stories/Documents/TSC.pdf
9. *Ontario Regulation 22/04* - Electrical Distribution Safety
   http://www.e-laws.gov.on.ca/html/source/regs/english/2004/elaws_src_regs_r04022_e.htm
10. *Measurement Canada*
    http://strategis.ic.gc.ca/epic/site/mc-mc.nsf/en/h_lm03862e.html

In the event of a conflict between this document and the Distribution Licence or regulatory Codes issued by the OEB, or the Electricity Act, the provisions of the Act, the Distribution License and associated regulatory Codes shall prevail.

When planning and designing for electricity service, Customers and their agents must refer to all applicable Provincial and Canadian electrical codes, and all other applicable federal, provincial, and municipal laws, regulations, codes and by-laws to also ensure compliance with their requirements. The work shall be conducted in accordance with the Ontario Occupational Health and Safety Act, the Regulations for Construction Projects and the E&USA (or the OHSC Safety) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- *Headings and underlining are for convenience only and do not affect the interpretation of these Rules.*
- *Words referring to the singular include the plural and vice versa.*
- *Words referring to a gender include any gender.*

1.4 Amendments and Changes

The provisions of these Conditions of Service and any amendments made from time to time form part of any Contract made between the Distributor and any connected Customer, Generator or their agents.

In the event of changes to this Conditions of Service, a Public notice shall be made in the form of either a notice in the local newspaper, or a notice on the Distributors' Website.

The Customer is responsible for contacting the Distributor to ensure that the Customer has, or to obtain the current version of the Conditions of Service. The Distributor may charge a reasonable fee to recover costs for providing the Customer with more than one copy of this document.

1.5 Contact Information

The Distributor and its agents can be contacted during normal working hours. Please refer to the Contact Listing in the Appendices for phone number of the Local Distribution Company servicing your area.

1.6 Customer Rights

In those instances where the Customer will own their secondary or primary service, the Customer has the right to hire a Contractor to supply and install the service.

The customer has the right to demand identification from any person purporting to be an authorized agent or employee of the distributor.

A customer, who believes that he has suffered damages to his property or equipment as a result of negligence on the part of the Distributor, may submit a written claim for damages to the Distributor. The Distributor will investigate the claim and respond in writing within 10 business days of the receipt of the claim.

1.7 Distributor Rights

In those instances where the Customer has the authority to hire a Contractor to construct plant which will become part of the Distributors' system, the Distributor shall have the right to require the Contractor to submit proof of previous experience and satisfactory performance, and, the Distributor shall have the right to investigate such proof and approve the Contractor prior to the Owner awarding a contract for the work to the Contractor.

The Distributor shall have access to Customer property in accordance with section 40 of the *Electricity Act, 1998*.

1.8 Disputes

If, following good faith negotiations between a customer or other market participant and the Distributor, a resolution cannot be reached, the dispute may be submitted to a dispute resolution process.

Any dispute which shall arise between the Distributor and a customer(s) and other market participants subject to the terms of these Conditions of Service concerning the rights, duties or obligations of the Distributor or others subject to these Conditions of Service, shall be subject to the following dispute resolution procedure:

Mediation

- Either party (the "Initiating Party") may invoke the dispute resolution procedure by sending a written notice to the other party (the "Respondent Party") describing the nature of the dispute and designating a representative of the Initiating Party with appropriate authority to be its representative in negotiations relating to the dispute. The responding Party shall, within five business days of the receipt of such notice, send a written notice to the Initiating Party, designating a representative of the Responding party with the appropriate authority to be its representative in negotiations relating to the dispute.

- Within ten business days of the receipt by the Initiating Party of the written notice of the Responding Party the designated representatives shall enter into good faith negotiations with a view to resolving the dispute. If the dispute is not resolved in thirty days of the commencement of such negotiations, or such longer period as may be agreed upon, either party may, by written notice to the other party, require that the parties be assisted in their negotiations by the Ontario Energy Board. In accordance with the OEB dispute resolution process, The Ontario Energy Board will complete its review of the dispute within 150 days.

SECTION 2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections

This section includes information that is applicable to all customer classes of the distributor. Items that are applicable to only a specific customer class are covered in Section 3.

2.1.1 Building that Lies Along

As provided in Section 28 of the Electricity Act 1998 the Distributor has the Obligation to Connect any Building that 'lies along" its distribution system subject to conditions outlined in section 2.1.3.
A building 'lies along" a distribution line if it can be connected to the distributor distribution system without an expansion or enhancement.

A Building that appears to 'lie along' a distribution line may be refused connection to that line should the distribution line not have sufficient capacity for the requested connection. In such instances, the distributor shall make an offer to connect which will include the cost of the enhancement.

2.1.2 Offer to Connect

The Distributor will make an Offer to Connect to any customer requesting a connection within the Distributors licensed territory. As required by the Distribution Code, the Offer to Connect must be Fair and Reasonable and be based on the distributors' design standard. The Offer to Connect must also be made within a reasonable time from the request for connection and the receipt of all required information from the Customer.

The Distributor may require a customer to pay all or a part of the costs of electrical plant installed to supply only that customer. Such capital contributions will be calculated using the guidelines set out by the OEB in the Distribution System Code. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.1.3 Connection Denial

The Distribution System Code in section 3.1 sets outs the conditions for a Distributor to deny connections. A Distributor is not obligated to connect a building within its service territory if the connection would result in any of the following:

- Contravention of existing Canadian Laws, and those of the Province of Ontario.

- Violations of conditions in a Distributors’ Licence.
- Use of a distribution system line for a purpose that it does not serve and that the Distributor does not intend to serve.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe work situation beyond normal risks inherent in the operation of the distribution system.
- A material decrease in the efficiency of the distributors’ distribution system.
- A material adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.
- Potential increases in monetary amounts that already are in arrears with the distributor

The distributor shall inform the person requesting the connection of the reason(s) for not connecting and, where the distributor is able to provide a remedy, make an offer to connect. If the distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection may be made.

2.1.4 Inspections Before Connections

The Distributor has the right to request an inspection prior to any connection.

All customer electrical installations shall be inspected and approved by the Electrical Safety Authority, referred to herein as the ESA.

The Distributor requires notification from the ESA of this approval prior to the connection of a customer's service.

Services that have been disconnected for a period of six months or longer shall also be inspected and approved by the ESA prior to reconnection.

Temporary services, for construction purposes, are approved by the ESA for a period of twelve months and must be re-inspected should the period of use exceed twelve months.

The Distributor reserves the right to inspect and approve Transformer rooms, Vaults and Pads prior to, during, and following the installation of equipment.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

Customer owned substations must be inspected by both the Electrical Safety Authority and the Distributor, prior to connection to the Distribution system.

Duct banks and road crossings shall be inspected and approved by the Distributor prior to the pouring of concrete and again before backfilling.

The Distributor reserves the right to inspect any underground trenches prior to backfilling.

The Distributor reserves the right to approve the installation and location of all submarine cable. All documentation and permits required for laying of submarine cable must be provided to the Distributor. The installation of submarine cable must meet the requirements of all governing legislation.

All work done on existing Distributor plant must be authorized by the Distributor and carried out in accordance with all applicable safety acts and regulations.

In accordance with the Distribution System Code, if the Distributor refuses to connect a building in its service territory that lies along one of its distribution lines, the distributor shall inform the person requesting the connection of the reasons for not connecting, and where the distributor is able to provide a remedy, make an offer to connect. If the Distributor is unable to provide a remedy to resolve the issue, it is the responsibility of the customer to do so before a connection can be made.

2.1.5 Relocation of Plant

The Distributor will, where feasible, accommodate requests to relocate electrical plant such as poles and metal enclosed equipment.

The customer will be required to pay all of the costs incurred by the relocation.

Requests by civic authorities to relocate distribution facilities will be done so in accordance with the appropriate regulations. See *Public Service Works on Highways Act*.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, the Distributor has the right to have supply facilities on private property registered against title to the property. Easements are required whenever the Distributors' underground or overhead plant is to be located on private property or crosses over an adjacent private property to service a Customer.

The Customer shall acquire and grant in the distributors name, at no cost to the Distributor, where required, an easement to permit installation and maintenance of service. The width and extent of this easement shall be determined by the Distributor. The easement shall be granted prior to connection of the service.

The Owner shall furnish to the Distributor, free and clear of all encumbrances, sufficient easements to enable the servicing of all existing or proposed developments or subdivisions from plants located on the Owners' property.

Sufficient property at suitable locations shall be made available for the purpose of the installation of distributors' assets.

The Customer will prepare at its own costs a reference plan and associated easement documents to the satisfaction of the Distributors' solicitor prior to its registration and register the easement plan. Details will be provided upon application for service.

Where surface restoration by the Distributor is required following any repairs or maintenance to a service, the Distributor will in so far as is practicable, restore the property to its original condition; and provide compensation for any damages caused by the entry that cannot be repaired.

2.1.7 Contracts

Standard Form of Contract - All customers will be requested to complete and sign the standard form of contract to apply for a connection. A Standard Contract for service shall be considered as being in force from the date it is signed by the Customer and the Distributor and shall remain in force until terminated by either party.

Implied Contract - In all cases, notwithstanding the absence of a formal contract, the taking and using of electrical energy from the Distributor by any Person or Persons constitutes the acceptance of the terms and conditions of all regulations, conditions and rates as established by the Distributor. Such acceptance and use of energy shall be deemed to be the acceptance of a binding contract with the Distributor and the Person so accepting shall be liable for payment for such energy and the contract shall be binding upon the Person's heirs, administrators, executors, successors or assigns.

Special Contracts - Special contracts that are customized in accordance with the service requested by the Customer normally include, but are not necessarily limited to, the following examples:

- *construction sites*
- *mobile facilities*
- *non-permanent structures*
- *special occasions, etc.*
- *generation*

2.2 Disconnection

The Distributor has the right and/or obligation to disconnect the supply of electrical energy to a Customer for causes including but not limited to:

(a) contravention of the laws of Canada or the Province of Ontario including the Ontario Electrical Safety Code;

(b) violation of conditions in a distributor's licence;

(c) materially adverse effect on the reliability or safety of the distribution system;

(d) imposition of an unsafe worker situation beyond normal risks inherent in the operation of the distribution system;

(e) a material decrease in the efficiency of the distributor's distribution system;

(f) inability of the distributor to perform planned inspections and maintenance;
(g) a materially adverse effect on the quality of distribution services received by an existing connection; and
(h) if the person requesting the connection owes the distributor money for distribution services, or for non-payment of a security deposit.

2.3 Conveyance of Electricity

2.3.1 Guaranty of Supply

The Distributor agrees to use reasonable diligence in providing a regular and uninterrupted supply but does not guarantee a constant supply or the maintenance of unvaried frequency or voltage and will not be liable in damages to the Customer by reason of any failure in respect thereof.

Customers requiring a high degree of security of supply or power quality are responsible to provide their own back-up or standby facilities.

When power is interrupted, or the Customer is experiencing power quality problems the Customer or their electrical contractor shall first ensure that interruption is not due to problems within the customer owned installation. If after verifying that the cause of the problem does not reside on the customers' installation, the customer shall contact the Distributor. The Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

Although it is the Distributors' policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customers' supply to maintain or improve the Distributors' system, or to provide new or upgraded services to other Customers. Whenever practical and cost effective, as determined by the Distributor, arrangements suitable to the Customer and the Distributor may be made to minimize any inconvenience. The Distributor will endeavor to provide the Customer with reasonable advance notice, except in cases of emergency, involving danger to life and limb, or impending severe equipment damage.

The Distributor will endeavor to notify Customers prior to interrupting the supply to any individual service. However, if an unsafe or hazardous condition is found to exist, or if the use of electricity by apparatus, appliances, or other equipment is found to be unsafe or damaging to the Distributor or the public, service may be discontinued without notice.

Depending on the outage duration and the number of Customers affected, the Distributor may issue a news release to advise the general public of the outage.

2.3.2 Power Quality

The distributor will respond to and take reasonable steps to investigate consumer power quality complaints and report to the consumer on the results of the investigation. The method and level of investigation will be at the discretion of the Distributor.

If the source of a power quality problem is caused by the consumer making the complaint, the distributor may seek reimbursement for the time and cost spent to investigate the complaint.

If the source of a power quality problem is caused by a consumer, the Distributor may direct the consumer to take corrective action. If the Consumer does not take such action within a reasonable time, the Distributor may disconnect the supply of power to the Customer. (*see section 2.2*)

2.3.3 Electrical Disturbances

There are levels of voltage fluctuation and other disturbances that can cause flickering lights and more serious difficulties for Customers connected to the Distributor distribution system.

Some types of electronic equipment, such as video display terminals, can be affected by the close proximity of high electrical currents that may be present in transformer rooms.

No electrical equipment, which may produce an undesirable system disturbance, shall be connected by a customer to a customer's service without prior approval of the Distributor.
Examples of equipment, which may cause disturbance, are large motors, welders and variable speed drives. In planning the installation of such equipment, the customer is required to consult with the Distributor.

The Distributor will endeavour to maintain voltage variation limits, under normal operating conditions, at the Customers' Delivery Points, as specified by the latest edition of the Canadian Standards Association, C235. However, more sensitive electronic equipment such as computers can be seriously affected by variations in quality of supply voltage. Customers who need electrical power of high quality and with rigid voltage tolerances are responsible for providing their own power conditioning equipment.

Customers requiring a three-phase supply should install protective apparatus to avoid damage to their equipment, which may be caused by the interruption of one phase, or non-simultaneous switching of phases of the Distributors' supply.

The customer shall provide such protective devices as may be necessary to protect his property or equipment from any disturbance beyond the control of the distributor.

2.3.4 Standard Voltage Offerings

2.3.4.1 For Secondary Voltage

The Supply Voltage governs the limit of supply capacity for any Customer. General guidelines for supply from overhead street circuits are as follows:

- *at 120/240 V. single phase, or*
- *347/600 V. three phase, four wire, or*
- *120/208 V three phase, four wire,*

OR

Where street circuits are buried, the Supply Voltage and limits will be determined upon application to the Distributor.

OR

Where the Customer or Developer provides a pad on private property;

- *at 120/240 V single phase, or*
- *at 120/208 V three phase, four wire, or*
- *at 347/600 V three-phase, four-wire*

2.3.4.2 For Primary Voltage

Primary supplies to transformers or customer-owned substations will be one of the following as determined by the Distributor:

- *2,400/4,160 volts 3 phase 4 wire*
- *4,800/8,320 volts 3 phase 4 wire*
- *7,200/12,400 volts 3 phase 4 wire*
- *8,000/13,800 volts 3 phase 4 wire*
- *16,000/27,600 volts 3 phase 4 wire*
- *27,600 volts 3 phase 3 wire delta*
- *44,000 volts 3 phase 3 wire*

The customer shall contact the Distributor when planning their service to verify standard transformer availability and supply capacity.

2.3.5 Voltage Guidelines

The Distributor maintains service voltage at the Customers' service entrance within the guidelines of C.S.A. Standard CAN3-C235 (latest edition) which allows variations from nominal voltage of: http://www.csa-intl.org/onlinestore/GetCatalogDrillDown.asp?Parent=542,

6% for Normal Operating Conditions
8% for Extreme Operating Conditions

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on a planned and programmed basis, but not necessarily on an emergency basis.

Where voltages lie outside the indicated limits for Extreme Operating Conditions, improvement or corrective action will be taken on an emergency basis. The urgency for such action will depend on many factors such as the location and nature of load or circuit involved, the extent to which limits are exceeded with respect to voltage levels and duration, etc.

2.3.6 Back-up Generators

Customers with portable or permanently connected emergency generation capability shall comply with all applicable criteria of the Ontario Electrical Safety Code and in particular, shall ensure that customer emergency generation does not back-feed on the Distributors' system.

To access the Code: http://www.esasafe.com/Corporate/gr_004.php?s=8
To review Generator Safety Info: http://www.esasafe.com/GeneralPublic/sgi_001.php?s=23

Customers with permanently connected emergency generation equipment shall notify the Distributor regarding the presence of such equipment.

The distributor reserves the right to have the connection of this equipment inspected.

Generation systems found to be feeding into the Distribution system without proper approval of the Distributor shall be subject to immediate disconnection.

2.3.7 Metering

2.3.7.1 General

2.3.7.1.1 Access

The Distributor or its agents shall have the right to access and read any of the Distributors' electricity meters on the Customer's premises.

All metering installations shall be accessible from a public area.

2.3.7.1.2 Costs

All the Distributor metering equipment located on the Customer's premises are in the care and at the risk of the Customer and if destroyed or damaged, other than by normal usage, the Customer will pay for the cost of repair or replacement.

Regardless of any charges for metering installations, all meters and meter instrumentation equipment shall remain the property of the Distributor and maintenance of this equipment shall be the Distributors' responsibility.

2.3.7.1.3 Voltage

Generally, metering will be at utilization voltage. Where the Distributor provides primary transformation, primary voltage metering will be allowed only in special circumstances following full discussion with the Distributor.

Customer-owned substations may require primary metering. The provisions required for these installations shall be specified and approved by the Distributor for each application.

2.3.7.1.4 Primary Metering

Primary metering units may be installed outdoors or within an electrical vault as outlined in the current Electrical Safety Code. Where the customer prefers not to provide an approved electrical vault, the Distributor at additional cost can provide a metering unit with non-flammable coolant.

2.3.7.1.5 Bulk Metering

Non-residential or mixed-use buildings will normally be bulk metered by a single meter. However, where specific areas are clearly and permanently defined and in other respects as a separate entity, individual metering of the loads may be required.

Individual residential condominium or apartment units should be metered individually to empower the residents with control over their individual costs. In such instances, one or more bulk meters may still be required at the facility for the purpose of calculating house loads and/or transformer allowances (on customer owned transformers) where applicable.

In all installations where the Customer requests revenue metering remote from the secondary entrance equipment or downstream from a Customer-owned dry-core transformer, provisions are required for a bulk meter directly after the main switch. This bulk metering is required in addition to any public metering provisions. The Customer will be required to contribute to the cost of the metering installation.

Where more than one meter is required, the meters shall be grouped where practical.

The customer shall permanently and legibly identify all metered services with respect to correct municipal 911 address and unit #. The identification shall be applied to all service switches and breakers and to all meter cabinets and meter mounting devices that are not immediately adjacent to the service switch. The customer shall insure that all service identifications are accurate and by not doing so will be held responsible. The Distributor shall issue a Meter Verification Sheet for this purpose to the owner or contractor.

In any case, a copy of the metering layout plan shall be forwarded to the Distributor for review and approval.

If the distribution of the metered load circuit is in dispute, (ie: circuits from one premise is found to supply a second premise) the Distributor reserves the right to transfer all accounts into the Property Owners' name until such time as the problem has been resolved, and the individual metering can be clearly identified with the individual units.

2.3.7.1.6 Locks

All devices on the line side of the Distributor metering shall have provisions for padlocking.

For commercial and industrial services the Customer's main switch shall have provisions for padlocking the switch handle in the open position, and the switch cover (or door) in the closed position.

When a disconnect device has been locked in the "OFF" position by the Distributor, under no circumstances shall anyone other than the Distributor or its authorized agent remove the lock.

At the discretion of the Distributor, a dual locking arrangement, a Distributor master key arrangement, a key box arrangement, or a copy of the access key will be required for access.

2.3.7.1.7 Meter Seals

All devices used by the Distributor for metering are sealed. Only the Distributor or its authorized agents have the authority to break this seal. Tampering with the seal will require the Distributor to investigate the cause of the tampering. Following the investigation, the proper authorities will be contacted as required (*ESA*, *Police*, *Fire*). The customer shall be responsible for all reasonable costs associated with the investigation.

2.3.7.2 Current Transformer Boxes

Where a current transformer box is required, it shall be CSA approved, of a size and type as stipulated by the Distributor, and include a provision for padlocks. A removable plate shall be provided in the box for mounting the equipment.

As an alternative to a separate CT box and meter, a single enclosure combining both functions may be feasible. Contact the Distributor for details.

In cases where the CTs only meter a portion of the metal clad switchgear (such as house loads), a separate disconnect switch must be installed ahead of the metering compartment so that the service can be de-energized without any interruption to the main service supply.

Generally, one house load meter only will be allowed. Additional house load meters will require authorization from the Distributor.

Conductors should enter the current transformer box at the top and leave at the bottom, or vice versa. If this cannot be arranged, the next largest CT box must be used to enable conductors to be trained in place. Where parallel conductors are used, the sum of the conductors will determine the size of the CT box to use. In all cases the Customer shall supply suitable cable termination lugs.

On all electrical services that require current transformers and the neutral for metering, an isolated neutral block shall be provided in the current transformer box.

2.3.7.3 Interval Metering

The Distribution System Code, as amended from time to time, requires the Distributor to meter Customers of specific load levels with pulse-recording meters, or interval meters, which are interrogated remotely. The Distributor, at its' sole discretion, may also require such metering on any customer whose load characteristics may have a significant impact on the Net System Load Shape, or where reasonable access to the meter for the purpose of acquiring metering data may be limited due to location.

A customer that requests interval metering shall compensate a distributor for all incremental costs associated with that meter, including the capital cost of the interval meter, installation costs associated with the interval meter, ongoing maintenance (including allowance for meter failure), verification and re-verification of the meter, installation and ongoing provision of communication line or communication link with the customer' s meter, and cost of metering made redundant by the customer requesting interval metering. The communication system utilized for interval meters shall be in accordance with the distributors' requirements.

Where such metering exists the Distributor will consider customer requests to provide a secondary pulse for load control or customer-owned metering at the customers' expense.

In keeping with the intent of the Legislation and accompanying amendments, once an interval meter installation is processed as part of the distributors' settlement process, and has affected the relevant changes to the distributors net system load, the installation must not be changed back to a non-interval meter installation.

Where a customer submits a request to read their own interval meter, the Distributor shall make this access available given the following conditions are met:

- The meter has the capability of read-only password protection
- The customer provides a signed copy of the "Interval Metering Access Agreement" to the Distributor.

2.3.7.3.1 Interval Metering Communications

- Solid-state recorders and/or Electronic Interval Meters installed by the Distributor have provision for remote interrogation. When a phone line is required for this purpose, the Owner will facilitate the provision of a telephone line in the metering cabinet for the Distributors' metering purposes.
- At its' sole discretion, for metering installations where loss of metering data would cause a substantial impact on the Distributors Settlement System and other customers, the Distributor may require the phone line to be dedicated for metering purposes only.
- When such dedicated phone lines are required, phone lines must be installed and functioning prior to the new service being energized
- A dedicated phone line is a voice quality telephone line, which is active 24 hours a day to the metering location extension jack, which is mounted on the metering board.

2.3.7.3.2 Smart Meters

The Ontario Government has mandated the installation of Smart Meters as a replacement to current metering technology. The LDC will install smart meters in accordance with regulations and policies set out by Government authorities.

Residential and small General Service customers, who are billed on an energy-only basis, will be provided with a smart meter free of charge during the smart meter conversion. Metering requirements for Large General Service customers will be reviewed in concert with any new Regulations.

2.3.7.4 Meter Reading

The Distributor will read all meters on a regularly scheduled basis whenever possible. If an actual meter reading is not obtained, the Customer shall pay a sum based on an estimated demand and/or energy for electricity used since the last meter reading.

2.3.7.5 Final Meter Reading

When a service is no longer required, or the Customer is switching Energy Providers, the Customer shall provide the Distributor sufficient notice of the date so that a final meter reading can be obtained. The Customer shall provide access to the Distributor or its agents for this purpose.

If a final meter reading is not obtained, the Customer shall pay a sum based on an estimated demand

and/or energy for electricity used since the last meter reading. Estimates will be based on available historical consumption.

2.3.7.6 Faulty Registration of Meters

Metering electricity usage for the purpose of billing is governed by the Federal Electricity and Gas Inspection Act and associated regulations, under the jurisdiction of Measurement Canada, Industry Canada. The Distributors' revenue meters are required to comply with the accuracy specifications established by the regulations under the above Act.

In the event of incorrect electricity usage registration, the Distributor will determine the correction factors based on the specific cause of the metering error and the Customer's electricity usage history. The Customer shall pay for all the energy supplied, a reasonable sum based on the reading of any meter formerly or subsequently installed on the premises by the Distributor, due regard being given to any change in the character of the installation and/or the demand.

If the incorrect measurement is due to reasons other than the accuracy of the meter, such as incorrect meter connection, incorrect connection of auxiliary metering equipment, or incorrect meter multiplier used in the bill calculation, the billing correction will apply for the duration of the error. The Distributor will correct the bills for that period in accordance with the regulations under the Act.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

2.3.7.7 Meter Dispute Testing

The Distributor will attempt to resolve billing enquiries. However, to give Customers confidence in the accuracy of electricity meters, the Distributor will conduct an internal investigation to verify the accuracy of any meter the Customer believes to be recording incorrectly. If the internal investigation does not resolve the matter, the Customer or the Distributor may request Measurement Canada to test the meter.
http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

If the test indicates that the meter is not accurate, the Customer's historic billing will be adjusted, and the Distributor shall pay the full costs of the meter dispute testing.

2.3.7.8 Location

The location of the indoor or outdoor meter shall be readily accessible at all times and acceptable to the Distributor. If a meter is recessed or enclosed after installation, without the prior approval of the Distributor, the service may be subject to disconnection.

The location of the service entrance, routing of duct banks, metering, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

In all locations where Commercial/Industrial revenue metering is accessible to the general public, a lockable enclosure or a room for service equipment and meters, shall be provided by the Owner at the discretion of the Distributor, as follows:

- *An electrical room reserved solely for metering equipment or*
- *Metal enclosed switchgear approved by the Distributor or*
- *A suitable metal metering cabinet or*
- *A vandal proof cage.*

2.3.7.9 Meter Mounting Heights

Provision for metering shall facilitate a practical mounting height for revenue meters in compliance with the Distributor's standard specifications and all applicable codes and regulations.

2.3.7.10 Environment

The following requirements apply to the areas allocated for revenue metering.

The customer to the satisfaction of the Distributor shall provide where there is the possibility of danger to workmen, or damage to equipment from moving machinery, dust, fumes, or moisture, protective arrangements.

A clear safe working space of not less than 1.2 m (48") in front of the installation from the floor to ceiling with a minimum ceiling height of 2.1 m (84") provided to insure the safety of the Distributor or other authorized employee(s) who may be required to work on the installation.

Where excessive vibration may affect or damage metering equipment, adequate shock-absorbing mounting shall be provided and installed by the customer.

2.3.7.11 Meter Sockets

The owner will supply and install a meter socket as specified by the Distributor. Meter sockets will be directly accessible to the Distributors' staff.

A listing of approved revenue metering sockets is available from the Distributor.

2.3.7.12 Cabinets

Where required by these Conditions of Service the Owner shall supply and install a meter cabinet to The Distributors' requirements.

Meter cabinets shall be installed indoors, except where special permission is granted by the Distributor to install the meter cabinet outside. In such cases, an approved weather proof, lockable, C.S.A. approved meter cabinet shall be provided by the Customer.

2.3.7.13 Metering Loops

Three-phase, four-wire services will require a loop for metering, within the meter cabinet, for all three phases.

Mineral insulated, solid, or hard drawn wire conductors are not acceptable as metering loops.

2.3.7.14 Metal Enclosed Switchgear

The following regulations apply to the installation of instrument transformers and metering equipment within metal enclosed switchgear.

The Distributor will provide the following revenue metering equipment as required:

- Colour coded secondary wiring
- Revenue meters

The Owner shall:

- Consult with The Distributor regarding the installation of metering equipment, which may include:
    - Potential transformers
    - Potential transformer fuse holders and fuses
    - Current transformers
    - Phone line for remote interrogation of meters
    - Duplicate Pulse Initiators
    - Provide complete shipping instructions for instrument transformers for those projects where these are to be provided by the Distributor for installation by the switchboard manufacturer.
    - Install instrument transformers, metering cabinet and conduit.
    - Each main bus bar to be drilled and tapped (10-32) or (10-24) on the line side of the removable current transformer link.

- Submit two copies of the manufacturer's switchboard drawings, for approval, dimensioned to show provision for and arrangement of The Distributors' metering equipment.

Meters shall be installed by the Distributor in a customer-owned metal cabinet of a size and type pre-approved by the Distributor, mounted at an approved location separate from the switchgear.

Tamper proof or sealable rigid conduit or any equally approved conduit of a size and type specified by the Distributor shall be installed between the CT compartment of the switchgear and the meter cabinet.

For conduit installations greater than 30 m (100'), in length or where several bends are necessary, larger conduits or other special provision may be required, at the discretion of the Distributor.

2.3.7.15 Switchgear Connected to Wye Source

Where a Wye source neutral connection is to be used or grounded, the Owner shall provide a conductor sized to the requirements of the Ontario Electrical Safety Code from the instrument transformer compartment to the neutral connection.

2.3.7.16 Four Quadrant Metering (Generation)

All Ontario Energy Board-licensed generators connected to the distribution system that sell energy and settle through the distributor's retail settlement process shall be required to install metering that meets the requirements of the Distribution System Code as approved by the Ontario Energy Board, and/or the Market Rules as approved by the Independent Electricity System Operator. http://www.theIESO.com/

2.3.7.17 Net Metering for Embedded Generation

Customers with specific generation facilities may reduce their net energy costs by exporting surplus generated energy back onto the utility distribution system. Surplus energy exported onto the utility distributions system will be calculated as a credit against the energy the customer consumes from the distribution system.

All customers wishing to become a Net Metering participant must meet all of the following conditions:

1. The electricity is generated primarily for the customer's own use;
2. The electricity generated is conveyed to the customer's own consumption point without reliance on the utility's distribution system;
3. The maximum cumulative output capacity of the generator does not exceed 500 kW; and
4. The electricity is solely generated from a renewable energy source (such as wind, drop in water elevation, solar radiation, agricultural bio-mass, or any combination thereof).

In order to participate in the Net Metering program, the customer will be required to meet all the parallel generation requirements for Connecting Micro-Generation Facilities (10 kW or less) or Other Generation Facilities (greater than 10 kW and less than 500 kW), as applicable to the generator size, as found in Section 3.5 - Embedded Generation Facilities

The customer must have a bi-directional revenue meter that records energy flow in both directions.

2.3.7.18 Ontario Power Authority (OPA) Standard Offer Program for Embedded Generation

The Ontario Power Authority has established a Standard Offer Program (SOP) to encourage and promote greater use of renewable energy sources such as wind, solar, photovoltaic (PV), renewable biomass, biogas, bio-fuel, landfill gas, or drop in water elevation for generating electricity. Renewable energy electricity generation projects with a capacity of 10 MW or less that meets the program's requirements may be connected to the distribution system in order to export electricity.

Generating facilities participating in the Standard Offer Program will connect directly to the distribution system at a voltage of 44kV or less. Output from the generating facility shall be metered in a manner to ensure proper collection of required information for settlements. Such metering may include:

a. for generators of 10 kW or less and connected to the line side of the load meter
   - (i) a bi-directional kWh meter to measure energy consumed and energy exported; or
   - (ii) a bi-directional interval meter to measure hourly energy consumed and energy exported

b. for all other generators, an interval meter must be installed.

In some instances, the load meter may also have to be changed in order to accommodate proper settlement calculations for the SOP. The generator will be solely responsible for any costs associated with the connection to the distribution system and any required metering installation.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for Service Connections are set out in the Distributors approved rates, (Miscellaneous Rates and Charges) and may be obtained by request from the Distributor. Notice of Rate revisions may be published in the local newspapers and or mailed out to all customers with the first billing issued at revised rates.

2.4.2 Energy Supply

The Distributor shall provide Customers connected to the Distribution System with access to electricity through Standard Supply Service as defined in the Retail Settlement Code published by the OEB or as mandated though Legislation or Regulations issued by the Ministry of Energy.

Disputes arising from charges relating to Standard Supply Service shall be directed to the Distributor.

Customers will be switched to their Retailer of choice only if the retailer has a Service Agreement with the Distributor. The Customer's authorized Retailer through the Electronic Business Transaction system (EBT) must make the Service Transfer Request (STR) in accordance with the rules established and amended from time to time by the Ontario Energy Board.

Disputes arising from charges relating to Retailer Service shall be directed to the Retailer.

The Distributor may, at its discretion, refuse to process a Service Transfer Request for a Customer to switch to a Retailer if that Customer owes money to the Distributor for Distribution Services and or Standard Supply Service.

2.4.2.1 Wheeling of Power

Customers considering delivery of electricity through the Distributors' Distribution System shall contact the Distributor for technical requirements and current applicable Rates.

2.4.3 Supply Deposits & Agreements

Whenever required by the Distributor, the Customer shall provide and maintain security as specified in the Distribution System Code. The Distributor shall require security amounts based on the existing security and deposit policies.

Where a customer proposes the development of premises that requires the Distributor to place equipment orders for special projects, the customer is required to sign the necessary Supply Agreements and furnish a suitable deposit before such equipment is ordered by the Distributor. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

2.4.4 Billing

The Distributor may, at its option, render bills to its Customers on either a monthly, bi-monthly, quarterly or annual basis. The option applicable to the customer shall be identified to the customer at the time of application for service.

Prorating of Service and Demand charges will be performed at the discretion of the Distributor.

2.4.4.1 Competitive Charges:

Are based on rates as determined by:

i. the Hourly Ontario Spot Market Price (HOEP); or
ii. the utilities Weighted Average Price (WAP) as determined by net system load; or
iii. the customers retailer contract rate; or
iv. the rates published by the OEB; or
v. Legislation or Regulations issued by the Ministry of Energy.

2.4.4.2 Non-competitive Charges:

Non-competitive Charges are based on rates approved by the Ontario Energy Board, and fall outside the scope of this document as they are adjusted on an annual basis. Approved rates as they relate to the transmission, distribution and other non-competitive elements may be attained through the utilities rate documents. These documents will be provided by the utility at the customer's request.

2.4.4.3 Billable Engineering Units:

Customers will be billed on:

i. actual or estimated meter reading data; or
ii. derived consumption data (Streetlights, sentinel lights and other scattered loads); or
iii. a flat rate, depending on the type of load being billed.

2.4.4.4 Use of Estimates:

In months where a bill is issued, but no reading is obtained, the Distributor estimates usage in order to determine billing quantities. The estimate is based on historical usage for the premise, or a pre-determined quantity if there is no historical usage information available.

2.4.5 Payments and Late Payment Charges

Bills are rendered for distribution services and electrical energy used by the Customer. Bills are payable in full by the due date.

Bills are due when rendered by the utility. A customer may pay the bill without the application of a late payment charge up to a due date, which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill. This due date shall be identified clearly on the customer's bill.

Where payment is made by mail, payment will be deemed to be made on the date post-marked. Where payment is made at a financial institution acceptable to the utility, payment will be deemed to be made when stamped/acknowledged by the financial institution or an equivalent transaction record is made.
A partial payment will be applied to any outstanding arrears before being applied to the current billing, unless special considerations have been made by the utility.

Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued or limited. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

The Distributor shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge may apply where the service has been disconnected due to non-payment.

The Customer will be required to pay additional charges for the processing of non-sufficient fund (N.S.F.) cheques.

2.4.6 Unauthorized Energy Use

The Distributor shall use its discretion in taking action to mitigate unauthorized energy use. Upon identification of possible unauthorized energy use, the Distributor shall notify, if appropriate, Measurement Canada, The Electrical Safety Authority, Police Officials, Retailers that service customers affected by an authorized energy use, or other entities.

The Distributor may recover from the parties responsible for the unauthorized energy use all costs incurred by the Distributor arising from unauthorized energy use, including an estimate of the energy used, inspection and repair costs.

A service disconnected due to unauthorized use of energy shall not be reconnected until such time as all arrears resulting from the unauthorized use has been resolved to the satisfaction of the Distributor.

Prior to reconnection, the Distributor shall require proper authorization from applicable authorities.

2.5 Customer Information

The Distributor reserves the right to request specific information from the customer in order to facilitate the normal operation of its business. Failure of a customer to supply such information may prevent the normal continuation of service.

The Retail Settlement Code as amended from time to time specifies the rights of customers and their retailers to access current and historical usage information and related data and the obligations of distributors in providing access to such information.

Under these requirements, the Distributor shall upon authorization by a customer make the following information available to the Customer or the Retailer that provides electricity to a customer connected to the Distributors' distribution system:

- The Distributors' account number for the customer,
- The Distributors' meter number for the meter or meters located at the customer's service address
- The customer's service address,
- The date of the most recent meter reading,
- The date of the previous meter reading,
- Multiplied kilowatt-hours recorded at the time of the most recent meter reading,
- Multiplied kilowatt-hours recorded at the time of the previous meter reading,
- Multiplied kW for the billing period (if demand metered),
- Multiplied kVA for the billing period (if available),
- Usage (kWh's) for each hour during the billing period for interval-metered customers
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.)
- Average distribution loss factor for the billing period

This information will be provided to the Customer / Retailer upon request twice per year at no charge. The Distributor may request a fee to recover costs for additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

The Distributor acknowledges that no confidential information regarding its' customers shall be released to a third party without the expressed prior written consent of the customer unless the request is rightfully received from the third party requesting the information, or the Distributor is legally required to disclose such information under the terms and in accordance with the Freedom of Information and Protection of Privacy Act, R.S.O. 1990, c. F.31.
HOTLINK http://www.collus.com/images/stories/Documents/Measurement Errors.pdf

SECTION 3 CUSTOMER SPECIFIC

3.1 Residential

This section refers to the supply of electrical energy to Customers residing in residential dwelling units.

3.1.1 General

Energy is generally supplied as single phase, 3-wire, 60-Hertz, having a nominal voltage of 120/240 Volts.

There shall be only one Delivery Point to a dwelling.

In circumstances where two existing services are installed to a dwelling, and one service is to be upgraded, the upgraded service will replace both of the existing services.

All new single-family homes will be required to install their primary and secondary service wires to the specifications contained within the Distributors' technical specification document.

Whether the method of supply will be overhead or underground will be at the discretion of the distributor. The Distributor will adhere to any existing regulations subject to requirements of authorities.

Unless specifically documented otherwise to the Customer, where the distributor has taken ownership of such plant all services installed by the Distributor or by an approved contractor using approved materials, will be maintained by the Distributor.

3.1.2 Early Consultation

The Customer shall supply a completed Site Planning document and related information to the Distributor well in advance of installation commencement. (see appendix) The information shall be supplied in a manner requested by the Distributor at the time of the application.

3.1.3 Standard Connection Allowance

For the purposes of calculating customer connection fees, the Basic Connection for Residential consumers is defined as 100 amp 120/240 volt overhead service.

The basic connection for each customer shall include;

i. supply and installation of overhead distribution transformation capacity or an equivalent credit for transformation equipment; and
ii. up to 30 meters of overhead conductor or an equivalent credit for underground services.

In the case of an upgrade to an existing service, where the existing service is below the basic connection, the credit up to the basic connection will apply.

Secondary services exceeding the basic 30 meter length may require specific design approved by the Distributor to ensure power quality.

3.1.4 Variable Connection Fees

Any requirements above the defined basic connection shall be subject to a variable connection charge to be calculated as the costs associated with the installation of connection assets above and beyond the basic connection. The distributor may recover this amount from a customer through a connection charge or equivalent payment.

3.1.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer’s expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like-for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

3.1.5.1 Secondary Service Connections

The Point of Demarcation for residential services up to and including 400 amps is at the line side of the Meter Base for Underground services, and at the top of the stack for Overhead services, beyond which the customer bears full responsibility for installation and maintenance.

The Point of Demarcation for residential services over 400 amps is at the secondary side of the transformer.

For Secondary Services wholly owned and maintained by the Customer, the Demarcation Point is the secondary connection at the transformer or the service bus.

The Customer shall install, own, and maintain the secondary conductor under any of the following conditions:

(a) conductor terminations are inside the Customer's building;
(b) conductor is installed beyond the service entrance;
(c) conductor is connected to a Primary Service; or
(d) conductor is a non-standard installation.

3.1.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.1.6 Supply Voltage

(a) A Residential building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.1.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.1.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Local Distribution Company and:

- Mounted 1.7 meters from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 meters of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.1.9 Overhead Service

The Owner will provide service equipment to both the Distributors' and ESA requirements, and be of sufficient height to maintain proper minimum clearances. The Owner's main switch and the overhead service conductors will be of compatible capacity.

3.1.10 Underground Service

Underground secondary services will be installed at the Owners' expense, to the Distributor's specifications. The Owner's main switch and the underground service conductors will be of compatible capacity.

3.1.11 Street Townhouses and Condominiums:

NOTE: Street Townhouses and Condominiums requiring centralized or bulk metering will be covered under section 3.2 of these Conditions of Service. Also 3.1.11.2

3.1.11.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system and services will be designed and installed.

The Owner will provide all of the civil works to accommodate the Distributor and will pay the complete cost of the electrical distribution system, design and services.

- The distribution system and services shall be underground unless otherwise approved.
- One service will be provided for each unit.
- The nominal service voltage will be 120/240 volts, 1 phase, 3 wire.
- The Distributor will approve the location of duct banks, service routings and meter bases.

- Distribution plant shall not be installed until grade is at +/- 150 mm of final grade unless otherwise approved by the Distributor.
- Street lighting will be to Municipal standards and installed at the Owner's expense.

3.1.11.2 Metering:

The Owner will supply and install meter sockets specified by the Distributor.

Multiple or grouped meter bases will be accepted only when prior approval has been given by the Distributor both as to type and proposed location. A completed meter verification form shall be provided to the distributor prior to energization.

Meter sockets will be located on the exterior front wall of the units and will be directly accessible to the Distributor.

- Mounted on the front wall 1.7 metres above finished grade to the centre of the meter
- Installed ahead of (on the line side of) the main disconnect switch
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

Normally the service will not be energized until the outside finish in the area of the revenue meter has been completed. If exceptions are made to this, then the general contractor will be responsible for ensuring that the meter is suitably protected while work is being done on the exterior wall adjacent to the meter. The general contractor will be entirely responsible for all costs for materials and labour for repairing or replacing a damaged meter. Meters must always remain fully accessible for reading, replacement, repair, and general maintenance. Customers and/or their contractors should contact the Distributor prior to enclosing meters and/or meter bases to ensure that safety and access are not compromised or the Distributor may disconnect the service until remedial action, as determined by the Distributor, are undertaken

3.1.12 Seasonal and Remote Dwellings:

Due to the varied nature of Seasonal and Remote Dwellings some special arrangements may be required to service these locations. Arrangements will be made in such a manner to provide services such as restoring power, maintenance of equipment or new construction requests to water access or remote customers, without endangering personnel or the public.

3.1.12.1 Service Information:

The Owner will enter into a Servicing Agreement with the Distributor, governing the terms and conditions under which the electrical distribution system services will be provided.

In the event of a power interruption, the Distributor will respond to and take reasonable steps to restore power. The Distributor reserves the right to recover costs from the customer for making false claims of interruptions.

3.1.12.2 Access:

All operations performed by the distributor and its agents shall be performed within the rules and regulations set out by the appropriate authorities including but not limited to: ESA, Ministry of Labour, Ministry of Transportation, etc.

- **Night crossings**

  The Distributors' transportation equipment will not be used to cross any water ½ hour before sunset and ½ hour after sunrise due to safety concerns. It will be at the discretion of the Distributor whether they will board customer owned transportation equipment in these circumstances.

- **Ice conditions**

  Recognizing seasonal ice hazards, the Distributor reserves the right to suspend water passage during freeze up and spring thaw, as well as any such time deemed unsafe by the Distributor.

- **Severe weather conditions**

  Recognizing that severe weather conditions may pose undue safety hazards, the Distributor reserves the right to postpone attempts to restore power until restoration can be performed in a safe manner.

3.1.13 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.2 General Service (Below 50 kW)

3.2.1 General

This section refers to the supply of electrical energy to General Service Buildings requiring a connection with a connected load less than 50 kW, and, Town Houses and Condominiums described in section 3.1.8 that require centralized bulk metering.

General Service buildings are defined as buildings that are used for purposes other than single-family dwellings.

3.2.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.2.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Below 50 kW) shall be recovered through a variable connection Fee.

3.2.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.2.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.2.5.1 Secondary Service Demarcations

A General Service Customer Demarcation Point is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Demarcation Point at the top of stack for overhead services or at the meter base for underground services.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.2.5.2 Primary Service Demarcations

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

3.2.6 Supply Voltage

(a) A General Service building is supplied at one service voltage per land parcel.

(b) Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

(c) The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.2.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.2.8 Metering:

The owner will supply and install a meter socket complete with collar acceptable to the Distributor. Meter sockets will be directly accessible to the Distributor and unless otherwise specified during the early consultation process:

- Mounted 1.7 metres from the finished grade to the center of the meter and, either on the exterior of the front of the building or, within 3 metres of the front of the building on the driveway side.
- Installed ahead of (on the line side of) the main disconnect switch.
- Installed in a location, which is and will remain unobstructed by fences, hedges, expansions, sunrooms, porch enclosures, and any other impediments.
- If the meter is not to be installed on the actual building, it is important to contact the Distributor for specific location instructions prior to installation.

For more details refer to section 2.3.7 in these Conditions of Service.

3.2.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.2.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.2.11 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.2.12 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.3 General Service (Above 50 kW)

3.3.1 General

This section refers to the supply of electrical energy to General Service Customers requiring a connection with a connected load greater than 50 kW.

3.3.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc.

3.3.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 50 kW) shall be recovered through a variable connection Fee.

3.3.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a "variable connection charge". The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.3.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Secondary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

3.3.5.1 Secondary Service Connections

A General Service Customer Demarcation Point for customers above 50 kW is at the secondary side of the transformer, or as otherwise set by the distributor, beyond which the customer bears full responsibility for installation and maintenance.

In some instances, where it is in the best interest of the operation of the distribution system, the Distributor may establish the Delivery point at the top of stack for overhead services or at the meter base for underground services.

The location of the service entrance, routing of duct banks and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Demarcation Point might be located on an adjacent property. In such cases, a registered easement must exist.

3.3.5.2 Primary Service Connections

For Primary Service, the Demarcation Point is the primary connection at the Distributor's Distribution system.

In some circumstances the owner may be required to construct a private pole line. Primary conductors will be terminated complete with cut-out(s) at the Demarcation Point by the Distributor at the owners' expense.

Where a private pole line is to be constructed by the Owner with an approved contractor, this shall be constructed to the ESA and the Distributors' requirements.

An electrical requirement in excess of 300 kVA may require a customer owned substation.

In some instances primary metering may be required.

3.3.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.
Depending upon the location of the building the supply voltage will be one of the following:

- *120/240 Volts 1 Phase 3 Wire*
- *120/208 Volts 3 Phase 4 Wire*
- *347/600 Volts 3 Phase 4 Wire*

Depending upon the location of the building Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

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

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.3.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

3.3.8 Metering:

Meter installations will be directly accessible to the Distributor. The owner will consult with the Distributor well in advance of installation commencement to allow the Distributor time for proper planning and ordering of equipment.

For more details refer to section 2.3.7 in these Conditions of Service.

3.3.9 Overhead Service:

In circumstances where Commercial buildings cannot reasonably be supplied electrical energy by an underground service, the Distributor shall use its' sole discretion based on acceptable industry practices in establishing the specific requirements for the service installation.

3.3.10 Underground Service:

Under normal circumstances, Commercial buildings are supplied electrical energy by an underground service through a single point of entry for each land parcel, at a location specified by the Distributor.

3.3.11 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line. The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.3.12 Supply of Equipment:

The Distributor supplies, installs and maintains subject to the variable connection fee:

- Primary switchgear.
- Primary transformation equipment.
- Meter and secondary metering transformers.

The Owner shall supply, install and maintain any additional equipment required for the connection beyond the point of Demarcation.

3.3.13 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.3.14 Inspection:

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.4 General Service (Above 500 kW)

3.4.1 General

This section refers to the supply of electrical energy to General Service Services requiring a connection at a connected load greater than 500 kW.

3.4.2 Early Consultation

Detailed regulations cannot be stated which would be applicable to all cases, therefore the Owner will consult with the Distributor in the early planning stages to ascertain the Distributors' requirements.

The Customer shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment, and coordination with ESA requirements etc.

Note: Larger services may require approval by the ESA to ensure compliance with their design requirements. The customer should contact the ESA early in the planning stages.

The Distributor will:

- *Advise the customer of the suitability of the in-service date*
- *Arrange with the customer for a Service Contract*
- *Review the submitted drawings; return one set to the customer with comments and/or approval. If requested by the Distributor, the customer shall resubmit the drawings where the comments are extensive and require major changes*
- *Specify the required main fuse link or relay setting for co-ordination with the system. In case of multiple transformer stations, a complete co-ordination study shall be submitted by the customer for approval.*
- *Make the final connection to the source of supply*
- *Determine metering requirements*
- *Advise the Transmitter of the particulars of the customer owned substation*

3.4.3 Standard Connection Allowance

All costs attributed to the connection of a new General Service customer (Above 500 kW) shall be recovered through a variable connection Fee.

3.4.4 Variable Connection Fees

All costs associated with the installation of connection assets shall be subject to a variable connection charge. The distributor may recover this amount from a customer through a connection charge or equivalent payment. If an expansion or enhancement of the distribution system is required to facilitate a connection, the LDC may need to perform an Economic Evaluation to establish the capital contribution required from the Customer. The Customer should review the attached Distribution Connection Process for further information.

3.4.5 Point of Demarcation

In all cases the final Demarcation Point will be the decision of the Distributor.

The Customer must obtain a Demarcation Point Location from the Distributor before proceeding with the installation of any service. Failure to do so may result in the Demarcation Point having to be relocated at the Customer's expense.

Maintenance of the portion of the Primary Service owned by the Distributor includes repair and like for-like replacement of a wire or cable that has failed irreparably. The Customer is responsible for all civil work, supports, vegetation and landscaping associated with any such repair or replacement of the portion of Secondary Service owned by the Distributor.

The Distributor shall perform the maintenance or replacement of all underground looped cables that form part of the Distribution plant circuits. Following maintenance, surface restoration by the Distributor will include only soil, sod, gravel or asphalt.

Where damage can be shown to be the Owner's liability, maintenance and repair are at the Owners' expense

The Distributor reserves the right to direct the operations of any customer owned switchgear connected to the distribution system including those located beyond the point of demarcation.

3.4.5.1 Service Installation

In General, the Demarcation Point for a General Service Customer with a demand of over 500 kW is on the primary side of the transformer at the first available distributor owned point of isolation, or as otherwise set by the distributor. This delivery point might be located on an adjacent property from which the Distributor has an authorized easement. In all cases the final Demarcation Point will be the decision of the Distributor.

The location of the service entrance, routing of duct banks, metering facilities, and all other works will be established through consultation with the Distributor. Failure to comply may result in relocation of the service plant at the Owner's expense.

The Distributor will install overhead supply lines and required cut-outs to the first point of support on private property. The location of this support must be approved by the Distributor and shall be within 30 metres of the Distributors' existing overhead plant. All costs for materials and labour shall be at the customers' expense.

The service pole or first point of support on private property shall be considered self-supported and shall be complete with suitable hardware for attaching the suspension insulators. The Customer shall be responsible for all costs associated with equipment, installation, and inspection.

Where the customer wishes an underground supply, the customer shall supply and install the underground cables and termination pole complete with primary switch, fuses and lightning arresters. The installation shall be subject to ESA inspection and specific approval of the Distributor. The customer owned termination pole must comply with items as prescribed by the Distributor.

At the Distributors' discretion, the customers' underground service may be connected to a termination pole owned by the distributor. In such cases, the Distributor shall supply and install at the customers expense, any required primary switch, fuses, and lightning arrestors.

When requested, the customer shall make provision in the substation switchgear or transformer, for loop feeding the Distributors' supply cables via load interrupter switches.

In some instances, primary metering may be required.

3.4.6 Supply Voltage

A General Service building is supplied at one service voltage per land parcel.

General Service connections above 500 kW may require a customer owned substation.

Depending upon the location of the building, Primary supplies to transformers and Customer owned Sub-Stations will be one of the following as determined by the Distributor:

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

The Owner shall make provision to take delivery at one of the nominal utilization voltages as specified by the Distributor. The Owner shall obtain prior approval from the Distributor for the use of any specific voltage at any specific location.

3.4.7 Access:

At the Distributors discretion, service locations requiring access to adjacent properties (mutual drives, narrow side setbacks, etc.) will require the completion of an easement in the Distributors' name, or a "Letter of Permission "from the property owner(s) involved.

The Customer will provide unimpeded and safe access to the Distributor at all times for the purpose of installing, removing, maintaining, operating or changing metering and distribution equipment.

Where the high voltage interrupting switches are located inside a building, a direct outside entrance to the switchgear room must be provided.

The outside door providing direct access to the transformer or switchgear room must be compliant with all applicable codes and requirements, and of a quality to be approved by the Distributor.

3.4.8 Metering:

The owner will supply and install provisions for metering following the details outlined both in these Conditions of Service, and technical documents provided to the customer during the consultation process.

For more details refer to section 2.3.7 in these Conditions of Service.

3.4.9 Sub-transmission Service:

The Owner will pay for the full cost of sub-transmission services and may in some circumstances be required to construct a private pole line.

The Distributor will terminate sub-transmission conductors complete with live line loops and hardware at the Demarcation Point.

3.4.10 Short Circuit Capacity:

The Owner shall ensure that the service entrance equipment has an adequate short-circuit interrupting capability.

3.4.11 Drawings

Apart from the regular drawings submission to the ESA, the customer shall provide two sets of the following drawings and details to the Distributor.

Survey Plan: prepared by an Ontario Land Surveyor, showing the property limits, registered plan and existing buildings or easements if any.

Site Plan: showing the location of the station relative to buildings, structures and set backs from adjacent property lines. The site plan shall also include the exact location of existing Distributor owned plant and the proposed route of the incoming supply.

Schematic or Single-Line Diagram: indicating the major components of the station and their electrical ratings. Where additions or alterations are being made, these shall be clearly distinguished from unchanged portions of the installation.

Electrical Details: sufficient details shall be provided in order to enable fast processing and approval of the station drawings. The following represents the minimum data required.

- Plan, elevation and profile views of the station structure, switchgear, transformer(s), termination poles, duct banks, etc.

- Dimensions to clearly indicate the electrical, physical and working clearances as well as relative location of all equipment.

- Pole or structure for dead-ending the Distributor lines shall be complete with suitable hardware for attaching the suspension insulators that will be supplied and installed by the Distributor.

- Fencing arrangement.

- Grounding details. (In the case of indoor metal enclosed switchgear, when the Distributor has operating control of any interrupter switches, the assembly shall further incorporate ground rod parking stands and stirrups per the Distributors Specifications.)

- Details of vault construction (if indoor substation).

- Manufacturer's drawings of metal-enclosed switchgear showing internal arrangement of equipment, clearances, means of access, interlocking and provision for personal safety. Where the Distributors' cables terminate in the switchgear, the customer shall provide suitable terminators for the size and type of cable as specified by the Distributor.

- When the customer's switchgear is used for loop feeding the Distributors' supply cables, provision for padlocking the in and out load interrupter switches and the associated bay doors shall be required.

- Indoor and outdoor switchgear assemblies shall contain a space heater and protective guard in each bay, along with thermostat(s), sized to promote air circulation and to prevent condensation from forming.

- At the discretion of the distributor, the customer shall make provisions for a future system neutral connection to the customer's dead-ending pole or structures installed by the Distributor. Where the Distributors' neutral terminates in the customer's switchgear, the customer shall provide a suitable connector on the ground bus for the size and type of cable specified by the Distributor.

3.4.12 Pre-Service Inspection

The customer shall present to the Distributor a final "Pre-service Inspection Report" a minimum of 3 working days before connection can be affected.

The "Pre-Service Inspection Report" shall outline and document the results of all tests and inspection carried out on the substation components. The information contained in the report must be to the satisfaction of the Distributor before connection can be authorized.

The "Pre-Service Inspection Report" shall be required in case of:

- ***New Substation***: *in which case all components of the substation shall be reported upon.*

- ***Modified substation***: *in which case all components of the substation shall be reported upon.*

Prior to connection of the service the Local Distribution Company requires notification from the Electrical Safety Authority that the electrical installation has been inspected and approved for connection.

Provision for metering shall be inspected and approved by the Distributor prior to connection.

The Distributor or Distributor-approved Contractor generally installs all services. All work done shall be as per the specifications of the Distributor and subject to inspection by the Distributor.

(Refer to section 2.1.4 for further inspection details)

3.5 Embedded Generation

3.5.1 General

An Embedded Generator shall provide the Distributor with proof of compliance of IESO or OEB registration Requirements, and appropriate Licences.

The Distributor shall collect costs reasonably incurred with making an offer to connect a generator from the entity requesting the connection. Costs reasonably incurred include costs associated with:

- Preliminary review for connection requirements.
- Detailed study to determine connection requirements.
- Final proposal to the generator.

A Generator that is or wishes to become connected to the distributors' distribution system shall enter into a Connection Agreement with the Distributor.

If damage or increased operating costs result from a connection with a Generator, the Generator shall reimburse the Distributor for these costs.

The Embedded Generator is responsible for providing suitable embedded generator equipment to protect his plant and equipment for any conditions on the distributor and interconnected transmission systems such as reclosing, faults and voltage unbalance.

To incorporate the connection of embedded generator to the distribution system, the line/feeder protection including settings and breaker reclosing circuits must be reviewed and modified if necessary by the distributor or transmission authority. This process may be complex and may require significant time.

The embedded generator must submit a proposed single line diagram and protection scheme for review to the distributor contact as identified by the distributor.

Based on the transformer connection proposed by the embedded generator additional significant protection cost may be incurred (e.g. delta HV transformer winding may require 3 phase HV breaker / reclosure device). The embedded generator shall not order the protection equipment and transformer until the station line diagram is reviewed and accepted by the distributor.

The purpose of the distributor review is to establish that the embedded generator electrical interface design meets the distributor requirements.

The protection schemes shall incorporate adequate facilities for testing/maintenance.

Negative phase sequence protection shall be installed where required, to detect abnormal system condition as well as to protect the generator.

The embedded generator may be required to install utility grade relays for those protections that could affect the distributor or transmission authority system.

The embedded generator may be required to submit a Ground Potential Rise study for review by the distributor, if telecommunications circuits are specified for remote transfer trip protection.

3.5.2 Protection

The embedded generator should provide protection systems to cover the following conditions:

3.5.2.1 Internal Faults:

The Generator should provide adequate protections to detect and isolate generator and station faults.

3.5.2.2 External Faults:

The protection system should be designed to provide full feeder coverage complete with a reliable DC supply. In some cases redundancy in protection schemes may be required.

Normally the following fault detection devices are required for synchronous generator(s) installation(s).

3.5.2.3 Ground Faults:

When the HV winding of the Generator station transformer is wye connected with the neutral solidly grounded, then ground over-current protection in the neutral is required to detect ground faults.

If the Embedded generator station transformer HV winding connected to the Distributor system is ungrounded wye or delta, then ground under-voltage and ground over-voltage protections shall be required to detect ground faults.

Depending on the size, type of generator and point of connection, a distributor may require the relaying system to be duplicated, complete with separate auxiliary trip relays and separately fused DC supplies to ensure reliable protection operation and successful isolation of the embedded generator.

3.5.2.4 Phase Faults:

To detect phase faults, at least one of the following protections should be installed with acceptable redundancy where required depending on fault values:

- Distance
- Phase directional over-current
- Voltage-restrained over-current
- Over-current
- Under-voltage

3.5.2.5 Islanding/Abnormal Conditions:

Voltage and frequency protections are required to separate the embedded generator from the distribution system for an islanded condition and thus maintain the quality of supply to distribution system customers. This also will enable speedy restoration of the distribution system.

Typically, the protections required to detect islanding/abnormal conditions are:

- Over-voltage
- Under-voltage
- Over-frequency
- Under-frequency
- Voltage-balance

The above protections should be timed to allow them to ride through minor disturbances.

3.5.3 Induction Generator

Due to the operating characteristics of the induction generator the protection package required is normally less complex than the synchronous generator. An embedded generator should design the protection scheme to trip for the same conditions as stated for synchronous generators. An induction generator is an asynchronous machine that requires an external source such as a healthy distribution system to produce normal 60 Hz power. Alternatively, if there is an outage in the distribution system then there is unlikely to be 60 Hz output from the induction generator. In certain instances, an induction generator may continue to generate electric power after the source is removed. This phenomenon, known as self-excitation, can occur whenever there is sufficient capacitance in parallel with the induction generator to provide the necessary excitation and when the connected load has certain resistive characteristics.

3.5.4 DC Remote Tripping / Transfer Tripping

Remote or transfer tripping may be required between the Generator and the feeder circuit breaker if the Generator is connected at a critical location in the distribution system. This feature will provide for isolation of the embedded generator when certain faults or system disturbances are detected at the feeder circuit breaker location.

Additional Protection Features, such as Remote Trip and Generator end open signal, may be required in some applications. Remote Trip Protection will often involve the participation of a neighboring or Host LDC. Early consultation is important to ensure a timely connection to the system.

3.5.5 Maintenance

An Embedded Generator shall have a regular scheduled maintenance plan to assure the Distributor that all connection devices and protection & control systems are maintained in good working order. These provisions shall be included in the Connection Agreement. A complete copy of the inspection report shall be delivered to the Distributor within 30 days.

In developing a maintenance plan, the Generator should consider the following requirements:

- Qualified personnel should carry out all inspections and repairs.
- Periodic tests should be performed on protection systems to verify that the system operates as designed. Testing intervals for protection systems should not exceed four (4) years for microprocessor-based systems and two (2) years for electro-mechanical based systems.
- Isolating devices at the point of connection should be operated at least once per year.
- The Generator facility should be inspected visually at least once per year to note obvious maintenance problems such as broken insulators or other damaged equipment.
- Any deficiencies identified during inspections shall be noted and repairs scheduled as soon as possible, with timing dependent on the severity of the problem, due diligence concerns (of both the Distributor and the Generator) and financial and material requirements. The Distributor shall be notified of any deficiencies involving critical protective equipment.
- The Distributor shall be provided with copies of all relevant inspection and repair reports that may affect the protection and performance of the Distributors' systems. The Distributor has the right to witness any relevant test being performed by the generator.

3.6 Embedded Market Participant

An Embedded Market Participant shall provide the Distributor with proof of compliance of IESO registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Market Participant must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

3.7 Embedded Distributor

An Embedded Distributor shall provide the Distributor with proof of compliance of IESO and OEB registration Requirements, and appropriate Licences.

Where the Conditions of Service of this Distributor exceed the technical requirements of any other licence or participant obligations, these Conditions of Service shall take precedence.

The Embedded Distributor must meet at a minimum, the standards as set out in these Conditions of Service in order to connect to the Distributors' distribution facilities.

Metering requirements of the Embedded Distributor shall be at the discretion of the Host LDC.

3.8 Miscellaneous Small Services

This section pertains to the supply of electrical energy for Street Lighting, Traffic Signals, Bus Shelters, Telephone Booths, Cable T.V. Amplifiers, Decorative Street Lighting, Bill Boards, and other similar small loads.

3.8.1 General

At the discretion of the Distributor, the service voltage will be:

120/240 volts, single phase three wire or
120 volts, single phase two wire or
347/600V three phase, four wire

The method and location of the supply will vary based on the conditions present on the Distributors' plant, and will be established for each application through consultation with the Distributor.

Where specified by the Distributor during the Early Consultation process, the Customer will provide underground ducts to the Distributor's specifications.

The Owner shall be responsible for all costs associated with the supply and installation of service conductors

The Distributor at the Owners' expense will install required transformation.

Where at the discretion of the Distributor, a meter is not installed, energy consumption will based on the connected wattage and the calculated hours of use.

Prior to energization of a service the Distributor will require notification from the ESA that the installation has been inspected and approved for connection.

3.8.2 Early Consultation

The Owner shall supply a completed Electrical Planning Requirements Form to the Distributor well in advance of installation commencement to allow the Distributor time for proper planning, ordering of equipment etc. Information required includes:

- Required in-service date
- Requested Service Entrance Capacity and voltage rating of the service entrance equipment
- Locations of other services, gas, telephone, water and cable TV
- Survey plan and site plan indicating the proposed location of the service equipment with respect to public rights-of way and lot lines.

3.8.3 Street Lighting

Town street-lighting that is designed, installed, and maintained by the Distributor shall be fully funded by the Municipality to ensure adherence to the Affiliate Relationship Code and the Distributors' Licence.

3.8.4 Traffic Signals

Traffic Signals and Crosswalk Lights are owned and maintained by the applicable road authority.

3.8.5 Bus Shelters

Bus Shelter Lighting is owned and maintained by the Customer.

3.8.6 Decorative Street Lighting

Such installations could be lighting for festive occasions or "neighbourhood character" street-scaping and will be maintained by the Customer.

SECTION 4 GLOSSARY OF TERMS

"Conditions of Service" means the document developed by the distributor in accordance with subsection 2.3 of the Distribution System Code, that describes the operating practices and connection rules for the distributor;

"Condominiums" are located on common land, which is the property of a condominium corporation or is owned by the Owner of all of the units (rental property). These units usually front onto internal roads that are also privately owned;

"Condominium Development" is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit and have direct outside access at ground level;

"Connection" means the process of installing and activating connection assets in order to distribute electricity;

"Connection Agreement" means an agreement entered into between a distributor and a person connected to its distribution system that delineates the conditions of the connection and delivery of electricity to or from that connection;

"Connection assets" means that portion of the distribution system used to connect a customer to the existing main distribution system, and consists of the assets between the point of connection on a distributors' main distribution system and the ownership Demarcation Point with that customer;

"Consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate;

"Customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;

"Demand meter" means a meter that measures a consumers' peak usage during a specified period of time;

"Demarcation Point" means the point at which the obligation of the Distributor ends and those of the Customer begin for the purposes of maintenance and repair of the distribution service;

"Disconnection" means a deactivation of connection assets, which results in cessation of distribution services to a consumer;

"Distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;

"Distribution losses" means energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows;

"Distribution loss factor" means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.;

"Distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out.

"Distribution system / plant" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose. A distribution system is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect a customer to the main distribution system;

"Distribution System Code," means the code, approved by the Board, and in effect at the relevant time, which, among other things, establishes the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems;

"Distributor" means a person who owns or operates a distribution system;

"Electricity Act" means the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A;

"Energy Competition Act" means the *Energy Competition Act, 1998*, S.O. 1998, c. 15;

"Electrical Safety Authority" or **"ESA"** means the person or body designated under the *Electricity Act* regulations as the Electrical Safety Authority;

"Embedded Distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor;

"Embedded Generation Facility" means a generator whose generation facility is not directly connected to the IESO-controlled grid but instead is connected to a distribution system;

"Embedded Load Displacement Generation Facility" means an embedded generation facility connected to the customer side of the revenue meter where the generation facility does not inject electricity into the distribution system for the purpose of sale;

"Embedded Market Participant" means a consumer who is a wholesale market participant whose facility is not directly connected to the IESO-controlled grid but is connected to a distribution system;

"Emergency" means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity, or that could adversely affect the reliability of the electricity system;

"Emergency backup generation facility" means a generation facility that has a transfer switch that isolates it from a distribution system;

"Enhancement" means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;

"Expansion" means an addition to a distribution system in response to a request for additional customer connections that otherwise could not be made; for example, by increasing the length of the distribution system;

"Four-quadrant Interval Meter" means an interval meter that records power injected into a distribution system and the amount of electricity consumed by the customer;

"Generate", with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system;

"Generation Facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system, and includes any structures, equipment or other things used for that purpose;

"Generator" means a person who owns or operates a generation facility;

"Geographic Distributor" with respect to a load transfer, means the distributor that is licensed to service a load transfer customer and is responsible for connecting and billing the load transfer customer;

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good practices, reliability, safety and expedition. Good utility practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

"Holiday" means a Saturday, Sunday, statutory holiday, or any day as defined in the Province of Ontario as a legal holiday;

"IESO" means the Independent Electricity System Operator established under the Electricity Act;

"IESO-Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IESO has authority to direct operation;

"Interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis;

"Large Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of 10MW or more;

"Lies Along" means a property can be connected to the distributor distribution system without an expansion or enhancement, and meets the conditions listed in the Conditions of Service of the distributor who owns or operates the distribution line.

"Load Transfer" means a network supply point of one distributor that is supplied through the distribution network of another distributor and where this supply point is not considered a wholesale supply or bulk sale point;

"Load Transfer Customer" means a customer that is provided distribution services through a load transfer;

"Market Rules" means the rules made under section 32 of the *Electricity Ac*t;

"Measurement Canada" means the Special Operating Agency established in August 1996 by the *Electricity and Gas Inspection Ac*t, 1980-81-82-83, c. 87., and Electricity and Gas Inspection Regulations (SOR/86-131);

"Medium Sized Embedded Generation Facility" means an embedded generation facility with a name-plate rated capacity of less than 10 MW and:

a) more than 500 kW in the case of a facility connected to a less than 15kV line;
b) more than 1 MW in the case of a facility connected to a 15 kV or greater line;

"Meter Service Provider" means any entity that performs metering services on behalf of a distributor, generator, or registered market participant;

"Meter Installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment;

"Metering Services" means installation, testing, reading and maintenance of meters;

"Micro Embedded Load Displacement Generation Facility" means an embedded load displacement generation facility with a name-plate rated capacity of 10 kW or less;

"Net Metering" means a settlement process for Embedded Generation behind a Load Customer meter as defined by Ontario Regulation 541/05

"Ontario Electrical Safety Code" means the code adopted by O. Reg. 164/99 as the Electrical Safety Code;

"Ontario Energy Board Act" means the *Ontario Energy Board Act, 199*8, S.O. 1998, c.15, Schedule B;

"Operational Demarcation Point" means the physical location at which a distributors' responsibility for operational control of distribution equipment including connection assets ends at the customer;

"Ownership Demarcation Point" means the physical location at which a distributors' ownership of distribution equipment including connection assets ends at the customer;

"Physical Distributor" with respect to a load transfer, means the distributor that provides physical delivery of electricity to a load transfer customer, but is not responsible for connecting and billing the load transfer customer directly;

"Point of Supply" with respect to an embedded generation facility, means the connection point where electricity produced by the generation facility is injected into a distribution system;

"Rate" means any rate, charge or other consideration, and includes a penalty for late payment;

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates;

"Regulations" means the regulations made under the *Act or the Electricity Act*;

"Retail", with respect to electricity means,

a) To sell or offer to sell electricity to a consumer
b) To act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
c) To act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributors' obligations and responsibilities associated with financial settlement among retailers and customers and provides for tracking and facilitating customer transfers among competitive retailers;

"Retailer" means a person who retails electricity;

"Service Area" with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;

"Small Embedded Generation Facility" means an embedded generation facility which is not a micro-embedded generation facility with a name-plate rated capacity of 500 kW or less in the case of a facility connected to a less than 15 kV line and 1MW or less in the case of a facility connected to a 15 kV or greater line;

“Smart Meter” means a device that measures electrical energy use (kilowatt-hours, kWh) on an hourly or sub-hourly basis and is part of an integrated data management system. The meter records, stores and transmits date and time-stamped meter readings to a utility’s computer to facilitate Time-of-Use and Hourly billing. Smart meters may also include other capabilities and features to aid in load management and energy conservation.

“Standard Offer” means a settlement process for distribution connected Embedded Generation under contract for supply with the Ontario Power Authority.

“Total losses” means the sum of distribution losses and unaccounted for energy;

“Townhouses” are usually a free hold property, the land is owned by the individual Owners of each unit, fronting onto a municipal street;

“Townhouse Development” is a structure or complex of structures each containing more than two residential units. A single residential customer would occupy each unit, and have direct outside access at ground level;

“Transmission System” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;

“Transmission System Code” means the Board approved code that is in force at the relevant time, which regulates the financial and information obligations of the Transmitter with respect to its relationship with customers, as well as establishing the standards for connection of customers to, and expansion of a transmission system;

“Transmit” with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;

“Transmitter” means a person who owns or operates a transmission system;

“Unaccounted-for Energy” means all energy losses that cannot be attributed to distribution losses. These include measurement error, errors in estimates of distribution losses and un-metered loads, energy theft and non-attributable billing errors;

“Un-metered loads” means electricity consumption that is not metered and is billed based on estimated usage;

“Validating, Estimating and Editing (VEE)” means the process used to validate, estimate and edit raw metering data to produce final metering data or to replicate missing metering data for settlement purposes;

“Wholesale Market Participant” means a person that sells or purchases electricity or ancillary services through the IESO-administered markets;

SECTION 5 APPENDICIES

Contact Information

Distribution Connection Process

Request For Connection Form

Electrical Planning Requirements Document

Electric Service Meter Base/ Service Verification Form

Contact Information

Local Distribution Company	Contact Phone Number	
Centre Wellington Hydro Ltd. Licence # ED-2002-0498	Phone: (519) 843-2900	730 Gartshore Street, Box 217 Fergus, Ont. N1M 2W8
COLLUS Power Corp. Licence # ED-2002-0518	Phone: (705) 445-1800	Box 189, 43 Stewart Road Collingwood, Ont. L9Y 3Z5
Grand Valley Energy Inc. Licence # ED-2002-0512	Phone: (519) 928-3112	P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Hydro 2000 Inc. Licence # ED-2002-0542	Phone: (613) 679-4093	265 St. Philippe Street P.O.Box 370 Alfred, Ont. K0B 1A0
Innisfil Hydro Distribution Systems Limited. Licence # ED-2002-0520	Phone: (705) 431-4321	2073 Commerce Park Drive Innisfil, Ont. L9S 4A2
Lakefront Utilities Inc. Licence # ED-2002-0545	Phone: (905) 372-2193	207 Division St. P.O. Box 577 Cobourg, Ont. K9A 4L3
Lakeland Power Distribution Ltd. Licence # ED-2002-0540	Phone: (705) 789-5442	5-45 Cairns Cres. Huntsville, Ont. P1H 2M2
Midland Power Utility Corporation Licence # ED-2002-0541	Phone: (705) 526-9361	16984 Highway #12 Midland, Ont. L4R 4P4
Orangeville Hydro Ltd. Licence # ED-2002-0500	Phone: (519) 942-8000	P.O. Box 400 - 400 C Line Orangeville, Ont. L9W 2Z7
Orillia Power Distribution Corporation Licence # ED-2002-0530	Phone: (705) 326-2495	360 West St. South, P.O. Box 398 Orillia, Ont. L3V 6J9
Parry Sound Power Corporation Licence # ED-2003-0006	Phone: (705) 746-5866	125 William Street Parry Sound, Ont. P2A 1V9
Rideau St. Lawrence Distribution Inc. Licence # ED-2003-0003	Phone: (613) 925-3851	985 Industrial Rd. P.O. Box 699 Prescott, Ont. K0E 1T0
Wasaga Distribution Inc. Licence # ED-2002-0544	Phone: (705) 429-2517	950 River Road West P.O. Box 20 Wasaga Beach, Ont. L0L 2P0
Wellington North Power Inc. Licence # ED-2002-0511	Phone: (519) 323-1710	290 Queen Street West, P.O. Box 359 Mount Forest, Ont. N0G 2L0
Westario Power Inc. Licence # ED-2002-0515	Phone: (519) 507-6937 Toll Free: 1-866-978-2746	24 Eastridge Road R.R. #2 Walkerton, Ont. N0G 2V0
West Coast Huron Energy Inc. Licence # ED-2002-0510	Phone: (519) 524-7371	64 West Street Goderich, Ont. N7A 2K4
Woodstock Hydro Services Inc. Licence # ED-2003-0011	Phone: (519) 537-3488	16 Graham Street P.O. Box 1598 Woodstock, Ont. N4S 0A8

Note: Licence Numbers published by OEB as of May 8, 2008

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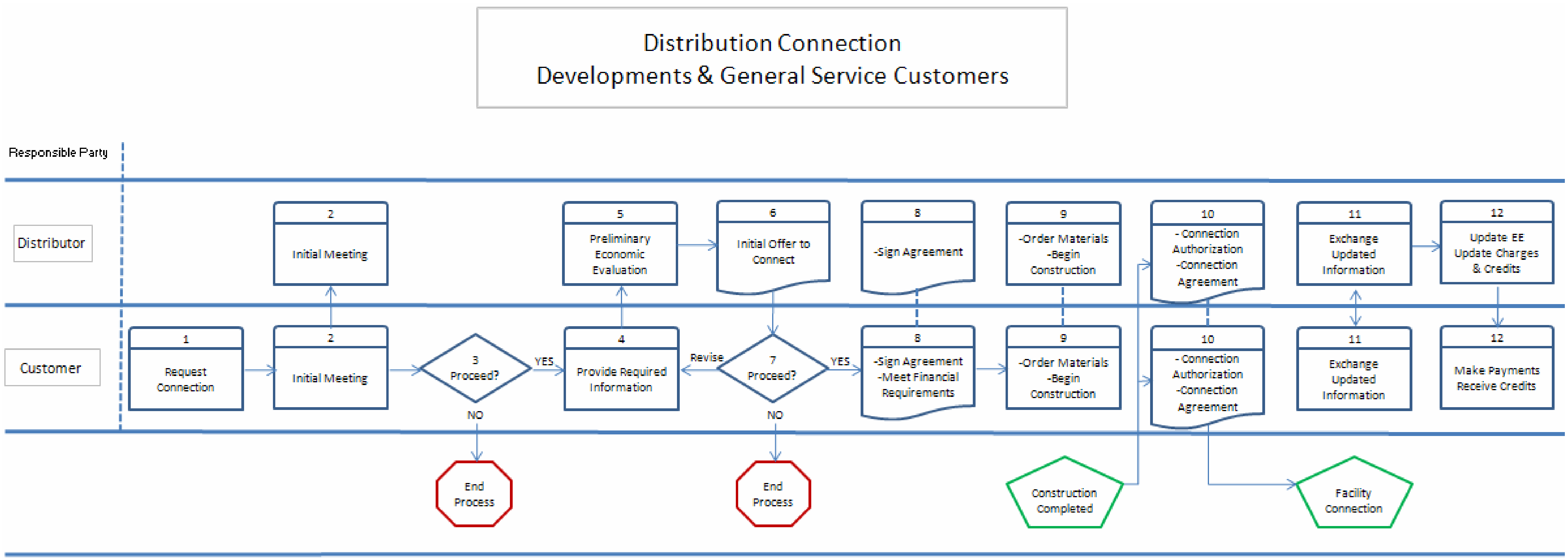
Distribution Connection



Distribution Connection
Developments & General Service Customers

If you are planning on building a Subdivision, Commercial Building, or an Industrial Development, the process of connecting to the Local Distribution Infrastructure will require coordination with the Distributor.

The following information in conjunction with the preceding chart is designed to assist the parties in meeting their respective obligations and facilitate the required connection. It is important to note although the steps identified in both the chart and the following descriptions need to be followed in proper order, some of the steps may be combined to help speed up the process if all the required information is provided in a timely manner.

Step 1 – Request for Connection

Customer submits a connection request to the Distributor. Initial request should at a minimum include the following information:

- Location of proposed development
- General description of development
- Proposed construction date
- Contact information for Development

Step 2 – Initial Meeting

Customer and Distributor meet to review proposed new development and connection requirements. Initial meeting will provide both parties with an opportunity to gain a better understanding of the proposed development and identify any issues related to timing and connection to the Distribution System.

Based on the information provided by the customer prior to the meeting, the Distributor will be able to provide at a high level:

- An initial concept of the type of work that may be required to facilitate a connection. ie:
  - Extension of an existing Feeder
  - Potential requirement for a new DS
  - Add a second or third phase to an existing feeder
- An understanding of the of the customer responsibilities
- An understanding of what must be managed by the Distributor
- An understanding of what may be contracted by the customer
- An estimated timeline required to provide connection facilities
- An initial estimate of required enhancement or expansion costs – note: more detailed estimates on costs will be provided with the Offer to Connect should the Customer choose to continue to Step 4.

Step 3 – Customer Decision
Based on the results of the initial meeting, the Customer decides on proceeding with the process or withdrawing their Request for Connection.

Step 4 – Customer Provides Required Information

If the Customer decides to proceed with the process for acquiring a connection, the Customer notifies the Distributor and provides the relevant detailed information as noted below:

- A statement noting if the Customer intends on managing the contestable work noted during the consultation
- Number of Residential Connections
- Residential – Type, Number, and size of units
- Number of Commercial / Industrial Connections
- Estimated Average Monthly consumption (at minimum winter & summer estimates)
- Estimated annual facility connections over five years from date of LDC system connection

The following information is also required however the Distributor reserves the right to perform the work internally or through an external consultant:

- Design and engineering specifications including but not limited to stamped site service drawings
- Determination of required Transformation based on estimated building loads
- Estimated Capital costs of facilities which would be assumed by the Distributor following energization

To assist the Customer in providing the required information, a submission summary sheet is provided as an attachment to this document.

Step 5 – Preliminary Economic Evaluation

Upon receipt of the required information from the Customer, if an expansion of the distribution system is required, the Distributor will perform a preliminary Economic Evaluation following the process as required in the Distribution System Code.

The Preliminary Economic Evaluation will assist the Distributor in calculating what (if any) portion of the Capital Costs the LDC will invest and will be used in the preparation of the Offer to Connect.

Step 6 – Offer to Connect

Using the information provided by the Customer, and following the completion of the Preliminary Economic Evaluation, the Distributor will prepare an “Offer to Connect”. The Offer to Connect will contain the following information:

- A statement as to whether the offer is a firm offer or an estimate to be revised after the actual costs are known
- The amount of Capital Contribution that will be required from the Customer
- The amount of the Expansion Deposit that will be required from the Customer
- A description of the costs related to the Capital Contribution
- The costs for inspections
- A description of the deliverables required from the Customer before Connection
- An estimated Connection Date

Step 7 – Customer Decision

Customer Reviews Offer to Connect and decides if they would like to continue with the project as planned. Three options are available to the Customer:

- Customer elects to drop the project a notice of withdrawal of the Request for Connection shall be provided to the Distributor.
- Customer would like to revise their Connection request, a notice informing the Distributor of the requested changes shall be provided to the Distributor (go back to Step 4)
- Customer agrees with the Offer to Connect,

Step 8 – Construction Agreement

Once the Customer accepts the Distributor's Offer to Connect, the parties shall enter into an agreement covering the construction and connection requirements and responsibilities.
The Customer and the Distributor sign the agreement and the Customer provides the financial deposits and/or guarantees as required.

Step 9 – Construction

Following receipt of signed Construction Agreement and required financial deposits and/or guarantees from the Customer, both parties shall begin ordering materials and begin construction.

Step 10 – Connection Authorization

Once construction is completed, both parties will ensure that inspections are completed and all required connection authorizations are in place. After receipt of a signed connection agreement and any additional financial contributions, the Distributor will authorize and connect the facility. If the customer is coordinating the work on the expansion facilities within the development, the customer is also required to provide "As-Built" drawings and a detailed material listing to ensure the Distributor has sufficient information in hand to verify system security prior to energization.

Step 11 – Exchange Updated Information

The Customer and the Distributor shall exchange any required updated information on the project including, but not limited to:

- All applicable Connection Authorizations
- All applicable Warranties
- Any new information that was provided as an estimate in Step 4
- Actual costs of any "capital works" related to the expansion facilities within the development
- Detailed site plan with appropriate Municipal Address information for individual services

Step 12 –Updated Economic Evaluation

As required, the Distributor shall recalculate the Preliminary Economic Evaluation using actual information acquired during and following the construction process.

If the development includes estimated connections that are not energized at the time of the initial Connection, the Distributor shall re-run the Economic Evaluation on an annual basis using actual customer connection information during the five (5) year connection horizon used in the initial Economic Evaluation.

Request for Connection

Development Name:	
Site Plan Identification	

Contact Information:

Contact Name:	
Street:	
Town:	
Postal Code:	

Requested Connection Date:	

Multi-Phase Development?	Y / N
If YES - Identify Phase	

Type & Number of Connections:

Average Monthly Consumption

		Per Unit - Winter	Per Unit - Summer
Residential:		Kwh's	Kwh's
Commercial:		Kwh's	Kwh's
Industrial:		Kwh's	Kwh's

Residential Dwelling Design:

Town Homes	
Semi-Detached	
< 1,500 SqFt Single Dwellings	
>1,500 <3,500 SqFt Single Dwellings	
> 3,500 SqFt Single Dwellings	

Connection Horizon

Year 1		
Year 2	Estimated connections in 1st year	
Year 3	Estimated connections in 2nd year	
Year 4	Estimated connections in 3rd year	
Year 5	Estimated connections in 4th year	
	Estimated connections in 5th year	

Capital Costs:

Distribution Infrastructure:	
Transformers:	
Ducts & Structures:	

Date: Submitted:	
Submitted By:	
Signature:	

Electrical Planning Requirements

It is essential that the following information be provided to:

a) enable an assessment to be made on the impact of the proposed project on the Electrical Distribution System.

b) enable the Distributor to prepare pertinent information for the developer.

Please supply answers to the following questions as soon as possible as electrical planning cannot proceed until the Distributor has reviewed this information.

Preliminary electrical site plan drawings are to be submitted together with this form. Electrical drawings are to be submitted to the Distributor for approval prior to any related job tenders or the commencement of any electrical construction. The drawings shall be drawn to a scale usable by the Distributor, shall show local pole locations, proposed transformer location, proposed electrical room/metering location and show how access to the metering would be gained (i.e.: the path to the metering).

Electrical site plan drawings are to be submitted to the Distributor on one (1) Paper copy and in an electronic format as approved by the Distributor.

Project Location: **(Municipal Address)** ____________________

Name of Project: ____________________

Name of Applicant: ____________________

Address: ____________________

Contact Name: ____________________

Address: ____________________

E-Mail: ____________________

Telephone: ( ) ____________________ **Fax:** ( ) ____________________

Service Classification (☒ as many as apply):

- ☐ Residential
- ☐ General Service < 50kW
- ☐ General Service > 50kW
- ☐ General Service >500kW
- ☐ Unmetered os Miscellaneous Load
- ☐ Temporary Service

Service Entrance Switchboard with Utility CT and PT Compartment ☐ Yes ☐ No

Capacity of Main Service (in Amperes):

Maximum rated capacity: ____________

Estimated Connected Load - Demand in kW:

Maximum initial Demand: ___________ kW

Maximum Future Demand: ___________ kW

What service voltage is required (☒ one only):

- ☐ 120/240 Volt Single Phase
- ☐ 120/208 Volt Three Phase
- ☐ 347/600 Volt Three Phase
- ☐ Primary

Metering Type (☒ one only):

- ☐ Single Meter
- ☐ Multiple Meters

Quantity of Meter installations

100A or less: _________

101A to 200A: _________

more than 200A: _________

Required In-Service Date:

Month / Day / Year ______/_______/_________

Comments: **Please use the back of this form for comments**

Signed: ____________________ **Date:** ____________________

(Representative of Applicant)

Name: ____________________ **Title:** ____________________

____

Electric Service Meter Base With Municipal Address Verification Form

LOCAL DISTRIBUTION COMPANY NAME: ______________________ **(UTILITY)**

This form **must** be completed by a Licensed Electrical Contractor or their legal representative prior to service connection. Accurate information must be provided or service will not be activated. ***(Sections A & B must be fully completed.)***

Electric Service Municipal Address: (Print) ______________________
Name of Owner: ______________________
Telephone: (________) ______________ Fax: (________) ______________
Name of Electrical Contractor: ______________________
Telephone: (________) ______________ Fax: (________) ______________

In area (A) provided below, a 'front-view' layout of the Electric Meter Base(s) is shown including an assigned number for each base. Provide Municipal Address (B) information for each corresponding meter base number for billing purposes.

(A) FRONT VIEW OF ELECTRIC METER BASE(S)	(B) MUNICIPAL ADDRESS (Print)
	1)
	2)
	3)
	4)
	5)
	6)
	7)
	8)

The following regulations are agreed upon by the undersigned with receipt of the completed form by an authorized representative of the Utility: *(A copy of the utility authorized form will be provided for your records.)*

1. That all information contained on this form is accurate.
2. That if any information is determined to be inaccurate, the Utility will not be able to energize the service connection(s).
3. That if any information has to be corrected by Utility personnel there will be applicable charges to prepare an amended form.
4. That an amended form must be signed and returned along with payment of any applicable invoice, as per Part 3, prior to further consideration as to the activation of the service connection.
5. **The Electrical Contractor completes Section (C) below to apply for service activation. A property owner MAY complete Section (D) rather than the contractor, to apply for service activation.**

(C) The undersigned acknowledges agreement to all terms and conditions contained on this form.
(Please print names in full)

Company Name: ______________________

Representative: ______________________

Title/Position: ______________________ Date: ________ (m / d / y)

Signature ______________________

(D) OPTIONAL if section (C) has been completed. The undersigned acknowledges agreement to all terms and conditions contained on this form.

Owner Name: *(Please print)* ______________________

Signature: ______________________ Date: ________ (m / d / y)

For COLLUS Power office use only:

Received : ______________________ Date ___/___/___ Approved: ______________________
(Authorized Rep's Name) (m / d / y) (Rep's Signature)

______________________ ______________________
(Address) (Telephone #)

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Changes in Conditions of Services

MPUC is a member of the CHEC group and originally filed the Conditions of Service with the Ontario Energy Board on May 1, 2003 and on August 1, 2008 filed an updated document with the Ontario Energy Board as V6.0. The Conditions of Service have been developed in accordance with the Distribution System Code and Guidelines set out by the Ontario Energy Board to reflect any recent changes.

List of Witnesses and their Curriculum Vitae

Those witnesses appearing on behalf of MPUC will include:

Phil Marley,	President & CEO, MPUC
Christine Bell,	CFO, MPUC
Bruce Bacon,	Borden, Ladner, Gervais
Stephen Motluk,	Elenchus Research Associates

Other witnesses may also appear on behalf of MPUC, the names of which will be provided.

MPUC will be pleased to provide CVs of witnesses if requested or if an oral hearing is necessary.

Budget Directives (Capital and Operating)

MPUC compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budgets. This budget information is compiled for both the Bridge and Test Years.

Revenue Forecast

The energy sales and revenue forecast model was updated to reflect the most recent information available. This model was then used to prepare the revenue sales and throughput volume and revenue forecast at existing rates for fiscal 2008 and 2009. The forecast is weather normalized as outlined in Exhibit 3, Tab 2 and considers such factors as economic outlook, new customer additions and load profiles for all classes of customers. In addition, the forecast has taken into account prior year's conservation and demand management initiatives through the third tranche CDM funding and the programs developed through the Ontario Power Authority.

Operating and Maintenance Expense Forecast

The operating and maintenance expenses for fiscal 2008 Bridge Year and 2009 Test Year have been forecasted using a zero based methodology. Each item is reviewed by account for each of the forecast years. A review of historical costs is completed and where applicable costs are included in the budget for the following year. New expenditures are added after the Management Committee approves the expenditure.

Capital Budget

The capital budget process begins with a review of the previous year's work. All capital expenditures are budgeted on a line by line and/or project basis based on need and forecasted customer growth. In addition, MPUC completes ground inspections throughout the year while completing maintenance on the distribution system and other infrastructure. From these inspections capital projects are identified and prioritized for inclusion in an upcoming capital budget year. A more detailed analysis of the Capital Budget process is provided at Exhibit 2, Tab 3, Schedule 8.

MPUC continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. The increase is attributed to some growth as well as replacing existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. In 2006 MPUC completed a substation assessment study which provided an analysis of infrastructure and a plan for the replacement taking into consideration future growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old. This study has provided MPUC with a comprehensive list of specifications and analysis to enable MPUC to plan for the replacement of the infrastructure.

Changes in Methodology

The following is a summary of the changes in methodology requested by MPUC in the current proceeding:

Capital Structure

MPUC has no current request to change the methodology addressing Capital Structure. MPUC will be undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system expansions. MPUC continues to expand and reinforce its distribution system in order to meet the demand of new and existing customers in its service territory. This increase is attributed to some growth, but is primarily a replacement of existing aging infrastructure in order to maintain safe and reliable delivery of electricity to our customers. In 2006 MPUC completed a substation assessment study which provided an analysis of existing infrastructure and a plan for the replacement taking into consideration the potential for future growth in our territory. To accommodate these increases MPUC will be seeking additional debt to bring our debt to equity ratio in line with Board approved ratios.

Finance

Financial Statements (2006)

A copy of the audited financial statements for 2006 is attached on the following pages.

Midland Power Utility Corporation

Financial Statements

For the year ended December 31, 2006

Midland Power Utility Corporation
Financial Statements
For the year ended December 31, 2006

Contents

BDO

BDO Dunwoody LLP
Chartered Accountants
and Advisors

300 Lakeshore Drive
Suite 300
Barrie Ontario Canada L4N 0B4
Telephone: (705) 726-6331
Fax: (705) 722-6588

www.bdo.ca

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, 2006 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.

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.

Goodwill contained in the financial statements must be tested for impairment under Canadian generally accepted accounting principles. 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 that would be necessary to reflect the impairment, if any, of goodwill.

In our opinion, except for the failure to perform procedures to determine if the value of goodwill has been impaired 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, 2006 and the results of its operations and the changes in its cash flows for the year then ended in accordance with the Canadian generally accepted accounting principles.

BDO Dunwoody LLP

Chartered Accountants

Barrie, Ontario

March 31, 2007

Midland Power Utility Corporation
Balance Sheet

December 31	2006	2005
Assets		
Current		
Cash (Note 1)	$ **2,044,719**	$ 1,586,119
Energy revenue accounts receivable	**1,537,382**	913,815
Other accounts receivable	**76,849**	65,332
Unbilled energy revenue	**2,093,687**	2,313,109
Due from shareholder (Note 4)	**37,446**	38,061
Inventory	**174,699**	125,671
Prepaid expenses (Note 14 (c))	**67,406**	147,763
Payments in lieu of corporate taxes receivable	**-**	32,893
	6,032,188	5,222,763
Property, plant and equipment (Note 2)	**5,735,722**	5,279,993
Goodwill	**1,260,000**	1,260,000
Regulatory assets net of regulatory liabilities (Note 3)	**990,312**	1,756,285
	$ **14,018,222**	$ 13,519,041

Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities	$ **3,433,388**	$ 2,793,597
Payments in lieu of corporate taxes payable	**413,766**	-
Due to shareholder (Note 4)	**50,158**	62,047
Current portion of customer deposits	**88,283**	99,494
	3,985,595	2,955,138
Construction deposits	**89,843**	57,450
Customer and retailer deposits	**106,193**	110,105
Due to shareholder (Note 4)	**1,122,519**	1,422,519
Employee future benefits (Note 5)	**131,225**	120,855
Other long-term liabilities (Note 6)	**302,544**	551,388
	5,737,919	5,217,455
Contingencies (Note 10)		
Shareholder's equity		
Share capital (Note 11)	**6,880,984**	6,880,984
Retained earnings	**1,399,319**	1,420,602
	8,280,303	8,301,586
	$ **14,018,222**	$ 13,519,041

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	2006	2005
Energy revenue (Note 4)	**$ 18,773,988**	$ 20,908,383
Cost of power	**16,001,955**	18,306,847
Net distribution revenue	**2,772,033**	2,601,536
Net service revenue (Note 12)	**57,777**	83,185
Other revenue (Note 13)	**300,376**	212,163
Expenses		
Administration	**757,461**	689,374
Amortization	**497,831**	434,411
Billing and collecting	**287,616**	324,082
Interest (Note 4 and 15)	**55,416**	71,037
Operations	**753,145**	600,083
Transition costs (Note 3)	**-**	113,836
	2,351,469	2,232,823
	778,717	664,061
Provision for payments in lieu of corporate income taxes and capital tax (Note 14)	**500,000**	11,209
Net income for the year	**278,717**	652,852
Retained earnings, beginning of year	**1,420,602**	767,750
Dividends	**300,000**	-
Retained earnings, end of year	**$ 1,399,319**	$ 1,420,602

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		2006		2005
Cash flows from operating activities				
Net income for the year	$	**278,717**	$	652,852
Adjustment for amortization		**497,831**		434,411
Gain on sale of property, plant and equipment		**-**		(4,200)
		776,548		1,083,063
Change in non-cash working capital:				
Energy revenue accounts receivable		**(623,567)**		601,759
Other accounts receivable		**(11,517)**		(13,107)
Unbilled energy revenue		**219,422**		(264,587)
Due from shareholder		**615**		(16,873)
Inventory		**(49,028)**		(9,331)
Prepaid expenses		**80,357**		(86,522)
Payments in lieu of corporate taxes receivable		**32,893**		(32,893)
Accounts payable and accrued liabilities		**639,792**		324,100
Payments in lieu of corporate taxes payable		**413,766**		-
Construction deposits		**32,393**		(5,545)
Customer and retailer deposits		**(15,123)**		24,821
Due to shareholder		**(11,889)**		(373,791)
		708,114		148,031
		1,484,662		1,231,094
Cash flows from investing activities				
Expenditures on property, plant and equipment		**(953,561)**		(542,060)
Proceeds on sale of property, plant and equipment		**-**		4,200
Net decrease (increase) in regulatory assets		**765,973**		(281,427)
		(187,588)		(819,287)
Cash flows from financing activities				
Repayment of amount due to shareholder		**(300,000)**		(300,000)
Increase (decrease) in employee future benefits		**10,370**		(845)
Net (decrease) increase in other long-term liabilities		**(248,844)**		19,388
Dividends paid		**(300,000)**		-
		(838,474)		(281,457)
Increase in cash during the year		**458,600**		130,350
Cash, beginning of year		**1,586,119**		1,455,769
Cash, end of year	$	**2,044,719**	$	1,586,119

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

December 31, 2006

Nature of Business

The corporation was incorporated under the laws of Ontario on May 1, 2002 and is licensed by the Ontario Energy Board ("OEB") as an electricity distributor. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

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.

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.

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 fulfil their obligations to connect and service customers, and has the authority to provide rate protection for certain electricity customers.

December 31, 2006

Regulation and Rate Setting continued

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.

Inventory

Inventory consists of parts and supplies acquired for internal construction, repair or completion of projects and are valued at the lower of average cost and replacement cost.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, overhead, engineering costs, and interest on funds used during construction when applicable. Also included in property, plant and equipment is 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:

Land rights	- 50 years	straight-line basis
Buildings	- 20 years	straight-line basis
Distribution system	- 25 years	straight-line basis
Supervisory equipment	- 15 years	straight-line basis
Rolling stock	- 5 and 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

December 31, 2006

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 has the following long-term investments. Cost for all investments noted was $Nil and therefore not included in these financial statements.

(i) ENERconnect Limited Partners, 1.2295%, recorded using the cost method.

(ii) Cornerstone Hydro Electric Concepts Inc., 1 common share, 6.25% interest, recorded using the cost method.

(iii) Utility Collaborative Services Inc., 1 common share, 25% interest, recorded using the equity method, no activity in 2006.

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. The audit report has been qualified with respect to the valuation of goodwill.

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

Construction Deposits

Construction deposits represent maintenance deposits and deposits for recoverable work.

December 31, 2006

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.

Pension Plan

The corporation offers a pension plan for its full-time employees thorough 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.

December 31, 2006

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, 2006. 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 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 Income Tax Act (Canada) and the Corporations Tax Act (Ontario) with 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 taxes payable method as permitted by the CICA and the OEB.

Under this method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable or receivable, it is expected that they will be reflected in the rates approved by the OEB at that point in time.

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.

During the year ended December 31, 2006 the corporation received OPC Rebates pertaining to consumption for the period beginning April 1, 2005 - July 31, 2006. These rebates totalling $838,966 were recognized as a reduction in the cost of power purchased.

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.

Financial Instruments

The corporation carries various forms of financial instruments. Unless otherwise noted, it is management's opinion that the corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments.

December 31, 2006

1. Cash

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

2. Property, Plant and Equipment

	2006		2005	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Land	**$ 365,298**	**$ -**	$ 365,298	$ -
Land rights	**32,555**	**15,060**	32,555	15,060
Buildings	**879,275**	**291,562**	870,323	264,686
Distribution system	**11,186,121**	**6,963,500**	10,560,450	6,604,158
Supervisory equipment	**315,046**	**183,697**	306,800	163,909
Rolling stock	**739,728**	**488,381**	695,128	666,390
Shop equipment	**269,550**	**238,724**	262,846	221,992
General office equipment	**237,525**	**202,825**	234,296	197,048
Stores equipment	**8,610**	**8,241**	8,610	8,118
Computer equipment and software	**507,874**	**413,870**	457,367	372,319
Wireless equipment	**69,891**	**69,891**	69,891	69,891
	$ 14,611,473	**$ 8,875,751**	$ 13,863,564	$ 8,583,571
Net book value		**$ 5,735,722**		$ 5,279,993

During the year the corporation purchased property, plant and equipment totaling $953,561 (2005 - $542,060) using cash.

3. Regulatory Assets and Liabilities

Net regulatory assets (liabilities) consist of:

	2006	2005
Pre-market opening energy electricity variance	$ -	$ 248,953
Transition costs	-	385,380
Smart meter initiatives	(11,643)	-
Deferral account for cash pension contributions	63,744	47,094
Deferral account for OEB annual cost assessments	14,041	19,083
Settlement variances	(94,736)	1,753,723
Carrying charges calculated OEB specified rate	49,874	205,943
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)	1,350,887	-
Recovery of regulatory assets up to December 31, 2005	-	(903,891)
Recovery of regulatory assets beginning May 1, 2006	(381,855)	-
	$ 990,312	$ 1,756,285

(i) Pre-market opening energy electricity variance

The OEB permitted the corporation to recognize the pre-market opening energy electricity variance for the period January 1, 2001 to April 30, 2002. The pre-market opening energy variance represents the difference between the LDC's cost of power purchased and the amount billed for the cost of power to customers at an average rate for the same period. The corporation has deferred these expenditures in accordance with the criteria set out in the AP Handbook.

In 2006, the pre-market opening energy electricity variance was reallocated to the recovery account (see note under additional information).

(ii) Transition costs

Transition costs represent costs related to the transition to a competitive electricity market mandated by the Electricity Act, 1998. The OEB has established rules outlining the transition costs which qualify for deferral and amortization against future revenue. Non-qualifying costs are expensed in the year they are incurred.

In 2005, the OEB approved a recovery of $60 per customer for transition costs included in regulatory assets. The transition costs in excess of the approved recovery of $113,836 were expensed in the statement of operations in 2005.

In 2006, the transition costs were reallocated to the recovery account (see note under additional information).

3. Regulatory Assets and Liabilities continued

(iii) Smart Meter Initiatives

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 LDCs. Variance accounts were established to track revenues collected with respect to smart meters and associated costs of the initiatives. In absence of rate regulation, revenues would have been higher in 2006 by $11,643 and expenses would have been higher in 2006 by $485.

(iv) 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. 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 continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2006 would have been $16,650 higher (2005 - $47,094).

(v) 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. 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 continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2006 would have been $11,512 higher (2005 - $12,613 higher).

(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 2006 would have been $638,968 higher (2005 - $706,003 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 variance has not been determined by the OEB.

3. 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 $51,430 (2005 - $36,937 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 are expected to be recovered over a four-year period, effective March 1, 2004 with an implementation date for consumption of April 1, 2004.

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 is for a two year period with rates effective May 1, 2006.

(ix) Additional Information:

Included in regulatory assets is $420,000 to reflect amounts owing to Hydro One with respect to low voltage charges relating to the time period beginning May 1, 2002 ending December 31, 2003. This amount was included in the rate submission for 2005 and is being recovered over a three year period through rates effective April 1, 2005.

Also included in regulatory assets is $440,390 representing low voltage charges for the period beginning January 1, 2004 ending April 30, 2006. In 2004, an estimate of the low voltage charges of $252,000 for the period beginning January 1, 2004 ending December 31, 2004 was included in the rate submission for 2006. The increase in the low voltage charges of $188,390 ($440,390 - $252,000) recorded in 2005 to reflect the amounts provided by Hydro One was included in the 2006 rate application.

Under the OEB's direction all regulatory asset balances as at December 31, 2004 plus accrued interest up to April 30, 2006 were applied against the regulatory asset recovery account. The result of this was a decrease in the settlement variances accounts of $2,481,073 and a decrease in the carrying charges of $75,893.

(ix) 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.

4. Related Party Transactions

The following summarizes the corporation's related party transactions for the year:

During the period the corporation paid municipal taxes to its shareholder, the Corporation of the Town of Midland, in the amount of $42,101 (2005 - $40,229). The corporation also paid $30,000 (2005 - $30,000) in annual lease fees for the substation properties.

During the year the corporation incurred interest expense on a promissory note payable to the shareholder of $50,158 (2005 - $62,047).

During the year the the corporation billed the shareholder in the amount of $610,736 (2005 - $578,017) for electricity. The corporation also billed the shareholder in the amount of $68,370 (2005 - $64,451) for work performed for maintenance of streetlighting and other services.

The corporation billed and collected for water and sewer $NIL (2005 - $2,219,745), on behalf of the Corporation of the Town of Midland (the corporation's shareholder). These services were terminated June 30, 2005.

During the year, the corporation billed the Corporation of the Town of Midland in the amount of $NIL (2005 - $52,500) for administrative services related to water and sewer collection and billing. These services were terminated June 30, 2005.

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 to related parties are as follows:

	2006	2005
Due from the Corporation of the Town of Midland (shareholder)	**$ 37,446**	$ 38,061
Interest payable to the Corporation of the Town of Midland	**$ 50,158**	$ 62,047

These balances are interest-free, payable on demand.

	2006	2005
Promissory note payable to the Corporation of the Town of Midland, bearing interest at the Government of Canada 10 year bond rate, with no specific terms of repayment	**$ 1,122,519**	$ 1,422,519

The fair value of the amounts due from/to the shareholder are not readily determinable due to their related party nature and terms.

5. Employee Future Benefits

An actuarial report was performed and dated January 15, 2007. The actuarial valuation was performed on the post-retirement obligations sponsored by Midland Power Utility Corporation as at December 31, 2006. The next actuarial valuation should be performed by December 31, 2009.

During 2003 the corporation discontinued its post-retirement life insurance, dental and health benefits to all employees. As at December 31, 2006, there are only seven (2005 - seven) retirees who retain the post-retirement life insurance benefit.

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

	2006	2005
Accrued benefit liability, beginning of year	**$ 120,855**	$ 121,700
Expense for the year	**(3,063)**	(845)
Change in post-retirement plan - (d) below	**13,433**	-
Projected accrued benefit obligation at December 31	**$ 131,225**	$ 120,855
Additional Disclosures:		
Unamortized actuarial gain (loss)	**$ -**	$ -

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 2.1% per annum.

(b) Interest (discount) rate
The obligation, as at December 31, 2006, of the present value of future liabilities was determined using an annual discount rate of 5.0%. This rate reflects the assumed long-term yield on quality bonds as at November 2006.

(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 has been increased since the 2003 valuation mainly as a result of a lower discount rate being used.

December 31, 2006

6. Other Long-Term Liabilities

	2006	2005
Hydro One Low Voltage Charges	**$ 302,544**	$ 551,388

The above amount represents the long-term portion of amounts owing to Hydro One for low voltage charges. The total amount owing is $552,204, of which $249,660 (2005 - $204,000) has been included in accounts payable and accrued liabilities as it is due to be repaid within one year. Refer to Note 3 for further information.

7. Pension Agreements

The corporation makes contributions to the 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 plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

The contribution rates for were 6.5% for employees earning up to $43,700 and 9.6% thereafter. The amount contributed to OMERS for 2006 was $112,022 (2005 - $87,084).

8. Credit Facility

The corporation has a line of credit with an authorized limit of $3,000,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances are calculated using the bank's prime rate and are payable monthly. As at December 31, 2006 the corporation had drawn a balance of $NIL on this credit facility.

The corporations line of credit has been pledged as security for the letter of credit provided to the Independent Electricity Systems Operation ("IESO") (see Note 10). As a result, the corporation's access to the $3,000,000 credit facility mentioned above is limited to $1,604,260.

9. 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. As at December 31, 2006, the corporation has not been made aware of any assessments for losses.

10. 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 proceedings 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.

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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas.

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.

(ii) The corporation is contingently liable as a guarantor for a letter of credit for $1,395,740 with its bank provided to the Independent Electricity Systems Operator (IESO) to secure the corporation's hydro purchase obligations.

(iii)The corporation has been named in a legal action for which the final outcome cannot be determined at this time. It is management's opinion that there will be no material uninsured liability arising from this claim. Therefore, no provision has been made for this claim in these financial statements.

December 31, 2006

11. 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:

		2006	2005
1,000	Common shares	$ 6,880,984	$ 6,880,984

12. Net Service Revenue

	2006	2005
Service revenue	$ 144,456	$ 186,231
Service costs	(86,679)	(103,046)
Net service revenue	$ 57,777	$ 83,185

13. Other Revenue

	2006	2005
Late payment charges	$ 13,730	$ 20,401
Interest earned	62,682	40,510
Pole rental	34,926	37,867
Office rental	53,593	52,284
Carrying charges on regulatory balances	51,430	36,937
Other	84,015	24,164
	$ 300,376	$ 212,163

December 31, 2006

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

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

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

	2006	2005
Income before provision for PILs	**$ 778,717**	$ 664,061
Prior year's tax loss	**(209,827)**	(436,838)
Net decrease (increase) in regulatory assets	**765,974**	(281,427)
Capital tax included in tax provision	**(4,000)**	(11,209)
Amortization expense in excess of capital cost allowance	**91,603**	70,419
Other items	**12,926**	(5,006)
Income for tax purposes	**$ 1,435,393**	$ -
Statutory Canadian federal and provincial tax rate	**34.49%**	-%
Provision for PILs	**$ 496,000**	$ -
Capital tax	**4,000**	11,209
Total provision	**$ 500,000**	$ 11,209

(b) Future Taxes

Future income taxes have not been recorded in the accounts as they are expected to be reflected through future distribution revenues.

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

	2006	2005
Current:		
Tax benefit of loss carry forwards	**$ -**	$ 76,000
Regulatory assets net of liabilities	**(358,000)**	(634,000)
	$ (358,000)	$ (558,000)
Long-Term:		
Employee future benefits	**$ 47,000**	$ 44,000
Property, plant and equipment	**100,500**	66,500
	$ 147,500	$ 110,500
Net future income tax asset	**$ (210,500)**	$ (447,500)

A future income tax (recovery) expense of $(237,000) (2005 - $235,250) has not been reflected in the provision for PILs.

14. Payments in Lieu of Corporate Income Taxes, Capital Taxes, and Future Income Taxes continued

(c) Corporate Minimum Tax

Included in prepaid expenses is $NIL (2005 - $60,000) of corporate minimum taxes which will be applied to reduce income tax expense once the corporation becomes taxable.

15. Statement of Cash Flows

	2006	2005
Interest paid	**$ 55,416**	$ 71,037
Interest received	**$ 62,682**	$ 40,510
PILs paid (net of amounts received)	**$ (3,586)**	$ (44,102)

16. Risk Management for Fair Value of Financial Assets and Liabilities

The fair value of the corporation's cash, accounts receivable, accounts payable and accrued liabilities and customer deposits approximate their carrying amount because of the short maturity of these instruments.

The fair value of the corporation's promissory note payable to the shareholder is not readily determinable due to the related party nature and terms.

Financial assets held by the corporation expose it to credit risk. Under the corporation's credit facility (Note 8), the corporation may have short-term borrowings for working capital purposes. These borrowings would expose the corporation to fluctuations in the bank's prime rate. As at December 31, 2006, there were no other significant concentrations of credit risk with respect to any class of financial assets.

17. Comparative Amounts

Certain comparative amounts presented in the financial statements have been restated to conform to the current year's presentation.

Financial Statements (2007)

A copy of the audited financial statements for 2007 is attached on the following pages.

Midland Power Utility Corporation

Financial Statements
For the year ended December 31, 2007

Midland Power Utility Corporation
Financial Statements
For the year ended December 31, 2007

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, 2007 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, 2007 and the results of its operations and the changes in its cash flows for the year then ended in accordance with the Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

Collingwood, Ontario

March 28, 2008

Midland Power Utility Corporation
Balance Sheet

December 31	2007	2006
Assets		
Current		
Cash and bank (Note 1)	**$ 1,779,157**	$ 2,044,719
Energy revenue accounts receivable	**1,038,123**	1,537,382
Other accounts receivable	**157,614**	76,849
Unbilled energy revenue	**2,070,115**	2,093,687
Due from shareholder (Note 5)	**45,546**	37,446
Inventory	**283,072**	174,699
Prepaid expenses	**86,859**	67,406
	5,460,486	6,032,188
Property, plant and equipment (Note 2)	**6,630,550**	5,735,722
Goodwill	**1,260,000**	1,260,000
Regulatory assets net of regulatory liabilities (Note 3)	**18,297**	990,312
	$ 13,369,333	$ 14,018,222
Liabilities and Shareholder's Equity		
Current		
Accounts payable and accrued liabilities (Note 4)	**$ 3,170,231**	$ 3,433,388
Payments in lieu of corporate taxes payable	**66,111**	413,766
Due to shareholder (Note 5)	**44,789**	50,158
Current portion of customer deposits	**186,103**	88,283
Construction deposits	**211,895**	89,843
	3,679,129	4,075,438
Customer and retailer deposits	**161,990**	106,193
Due to shareholder (Note 5)	**1,122,519**	1,122,519
Employee future benefits (Note 6)	**127,541**	131,225
Other long-term liabilities (Note 7)	**52,884**	302,544
	5,144,063	5,737,919
Contingencies (Note 10)		
Shareholder's equity		
Share capital (Note 12)	**6,880,984**	6,880,984
Retained earnings	**1,344,286**	1,399,319
	8,225,270	8,280,303
	$ 13,369,333	$ 14,018,222

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	2007	2006
Energy revenue (Note 5)	**$ 19,622,987**	$ 18,773,988
Cost of power (Note 18)	**16,823,128**	16,001,955
Net distribution revenue	**2,799,859**	2,772,033
Net service revenue (Note 13)	**58,500**	57,777
Other revenue (Note 14)	**318,912**	300,376
	3,177,271	3,130,186
Expenses		
Administration	**798,331**	757,461
Amortization	**523,913**	497,831
Billing and collecting	**311,868**	287,616
Interest (Notes 5 and 16)	**53,821**	55,416
Operations	**657,371**	753,145
	2,345,304	2,351,469
	831,967	778,717
Provision for payments in lieu of corporate income taxes and capital tax (Note 15)	**587,000**	500,000
Net income for the year	**244,967**	278,717
Retained earnings, beginning of year	**1,399,319**	1,420,602
Dividends (Note 5)	**300,000**	300,000
Retained earnings, end of year	**$ 1,344,286**	$ 1,399,319

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	2007	2006
Cash flows from operating activities		
Net income for the year	$ 244,967	$ 278,717
Amortization	523,913	497,831
	768,880	776,548
Changes in non-cash working capital:		
Energy revenue accounts receivable	499,259	(623,567)
Other accounts receivable	(80,765)	(11,517)
Unbilled energy revenue	23,572	219,422
Due from shareholder	(8,100)	615
Inventory	(108,373)	(49,028)
Prepaid expenses	(19,453)	80,357
Payments in lieu of corporate taxes receivable	-	32,893
Accounts payable and accrued liabilities	(263,157)	639,792
Payments in lieu of corporate taxes payable	(347,655)	413,766
Construction deposits	122,052	32,393
Due to shareholder	(5,369)	(11,889)
	(187,989)	723,237
	580,891	1,499,785
Cash flows from investing activities		
Expenditures on property, plant and equipment	(1,418,741)	(953,561)
Net decrease in regulatory assets	972,015	765,973
	(446,726)	(187,588)
Cash flows from financing activities		
Repayment of amount due to shareholder	-	(300,000)
Customer and retailer deposits	153,617	(15,123)
Increase (decrease) in employee future benefits	(3,684)	10,370
Net decrease in other long-term liabilities	(249,660)	(248,844)
Dividends paid	(300,000)	(300,000)
	(399,727)	(853,597)
Increase (decrease) in cash during the year	(265,562)	458,600
Cash and bank, beginning of year	2,044,719	1,586,119
Cash and bank, end of year	$ 1,779,157	$ 2,044,719

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 Ontario on May 1, 2002 and is licensed by the Ontario Energy Board ("OEB") as an electricity distributor. The incorporation was required in accordance with the provincial government's Electricity Act, 1998.

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.

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.

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.

December 31, 2007

Regulation and Rate Setting continued

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.

Inventory

Inventory consists of parts and supplies acquired for internal construction, repair or completion of projects and are valued at the lower of average cost and replacement cost.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost less accumulated amortization. Costs may include material, labour, contracted services, overhead, engineering costs, and interest on funds used during construction when applicable. Also included in property, plant and equipment is 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:

Land rights	- 50 years	straight-line basis
Buildings	- 20 years	straight-line basis
Distribution system	- 25 years	straight-line basis
Supervisory equipment	- 15 years	straight-line basis
Rolling stock	- 5 and 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

December 31, 2007

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 has the following long-term investments. Cost for all investments noted was $Nil and therefore not included in these financial statements.

(i) Cornerstone Hydro Electric Concepts Inc. (CHEC), 1 common share, 6.25% interest, recorded using the cost method.

(ii) Utility Collaborative Services Inc., 1 common share, 25% interest, recorded using the equity method.

December 31, 2007

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.

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 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.

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.

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.

December 31, 2007

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, 2007. 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 taxes payable method as permitted by the CICA and the OEB.

Under this method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable or receivable, it is expected that they will be reflected in the rates approved by the OEB at that point in time.

Midland Power Utility Corporation
Summary of Significant Accounting Policies

December 31, 2007

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.

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.

Financial Instruments

On January 1, 2007, the corporation retroactively adopted, without restatement of prior periods, CICA Handbook Section 3861, "Financial Instruments - Disclosure and Presentation" and Section 3855, "Financial Instruments - Recognition and Measurement". These new Handbook Sections provide comprehensive requirements for the recognition and measurement of financial instruments.

Under these new standards, 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 transitional provisions require these new standards to be adopted retroactively, without restatement of prior years.

All transactions related to financial instruments are recorded on a settlement date basis.

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.

Other financial liabilities
Other financial liabilities are comprised of trade payables, customer deposits, construction deposits and other long-term liabilities. 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:

Capital Disclosures

CICA Handbook Section 1535, Capital Disclosures, requires disclosure of an entity's objectives, polices and processes for managing capital, quantitative data about what the entity regards as capital and whether the entity has complied with any capital requirements and, if it has not complied, the consequences of such non-compliance. This standard is effective for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2007. The corporation is currently assessing the impact of the new standards.

Inventories

The CICA has issued Section 3031, Inventories, which provides guidance on determining cost as well as other recognition, measurement, disclosure and presentation issues related to inventories. The standard includes guidance on the treatment of excess capacities, inventory valuation and write-downs and additional elements to be considered in measuring inventory costs. The new standard is effective for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. The corporation does not expect the adoption of these changes to have a material impact on its financial statements.

General Standards on Financial Statement Presentation

CICA Handbook Section 1400, General Standards on Financial Statement Presentation, has been amended to include requirements to assess and disclose an entity's ability to continue as a going concern. The changes are effective for interim and annual financial statements beginning on or after January 1, 2008. The corporation does not expect the adoption of these changes to have a material impact on its financial statements.

International Financial Reporting Standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards ("IFRS") over a transition period expected to end in 2011. The impact of the transition to IFRS on the corporation's financial statements has yet to be determined.

December 31, 2007

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. Property, Plant and Equipment

	2007		**2006**	
	Cost	**Accumulated Amortization**	Cost	Accumulated Amortization
Land	**$ 365,298**	**$ -**	$ 365,298	$ -
Land rights	**32,555**	**15,060**	32,555	15,060
Buildings	**916,499**	**319,592**	879,275	291,562
Distribution system	**12,224,097**	**7,359,442**	11,186,121	6,963,500
Supervisory equipment	**337,163**	**204,497**	315,046	183,697
Rolling stock	**823,773**	**469,368**	739,728	488,381
Shop equipment	**302,675**	**246,969**	269,550	238,724
General office equipment	**246,273**	**208,945**	237,525	202,825
Stores equipment	**8,610**	**8,364**	8,610	8,241
Computer equipment and software	**668,532**	**462,688**	507,874	413,870
Wireless equipment	**69,891**	**69,891**	69,891	69,891
	$ 15,995,366	**$ 9,364,816**	$ 14,611,473	$ 8,875,751
Net book value		**$ 6,630,550**		$ 5,735,722

During the year the corporation purchased property, plant and equipment totaling $1,418,741 (2006 - $953,561) using cash.

3. Regulatory Assets and Liabilities

Net regulatory assets (liabilities) consist of:

	2007	2006
Smart meter initiatives	**$ (13,432)**	$ (11,158)
Deferral account for cash pension contributions	**63,744**	63,744
Deferral account for OEB annual cost assessments	**14,041**	14,041
Settlement variances	**(396,528)**	(95,221)
Carrying charges calculated using OEB specified rate	**71,937**	49,874
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)	**1,350,887**	1,350,887
Recovery of regulatory assets beginning May 1, 2006	**(1,072,352)**	(381,855)
	$ 18,297	$ 990,312

(i) Smart Meter Initiatives

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. In absence of rate regulation, revenues would have been higher in 2007 by $21,040 (2006 - $11,643) and expenses would have been higher in 2007 by $18,766 (2006 - $485).

(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 continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2007 would have been $NIL higher (2006 - $16,650 higher).

3. 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 continues to be calculated and attract carrying charges in accordance with the OEB's direction. In the absence of rate regulation, operating expenses in 2007 would have been $NIL higher (2006 - $11,512 higher).

(iv) 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 2007 would have been $147,304 lower (2006 - $638,968 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.

(v) 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 $22,063 (2006 - $51,430 lower)

(vi) 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 are expected to be recovered over a four-year period, effective March 1, 2004 with an implementation date for consumption of April 1, 2004.

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 is for a two year period with rates effective May 1, 2006.

3. Regulatory Assets and Liabilities continued

(vii) Additional Information:

Included in regulatory assets is $420,000 to reflect amounts owing to Hydro One with respect to low voltage charges relating to the time period beginning May 1, 2002 ending December 31, 2003. This amount was included in the rate submission for 2005 and is being recovered over a three year period through rates effective April 1, 2005.

Also included in regulatory assets is $440,390 representing low voltage charges for the period beginning January 1, 2004 ending April 30, 2006. In 2004, an estimate of the low voltage charges of $252,000 for the period beginning January 1, 2004 ending December 31, 2004 was included in the rate submission for 2006. The increase in the low voltage charges of $188,390 ($440,390 - $252,000) recorded in 2005 to reflect the amounts provided by Hydro One was included in the 2006 rate application.

Under the OEB's direction all regulatory asset balances as at December 31, 2004 plus accrued interest up to April 30, 2006 were applied against the regulatory asset recovery account. The result of this was a decrease in the settlement variances accounts of $2,481,073 and a decrease in the carrying charges of $75,893.

(viii) 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.

4. Accounts Payable and Accrued Liabilities

	2007	2006
IESO accounts payable	**$ 1,263,840**	$ 1,290,403
Trade accounts payable	**1,534,602**	1,409,355
Accrued liabilities	**371,789**	733,630
	$ 3,170,231	$ 3,433,388

December 31, 2007

5. 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:

	2007	2006
Revenue		
- Electricty charges	$ 614,473	$ 610,736
- Maintenance of streetlighting and other services	99,694	68,370
Expenses		
- Municipal taxes	43,217	42,101
- Lease fees for substation properties	30,000	30,000
- Interest expense	44,789	50,158
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) related parties are as follows:

	2007	2006
Due from shareholder - Corporation of the Town of Midland	$ 45,546	$ 37,446
Due to shareholder - Interest payable to the Corporation of the Town of Midland	$ (44,789)	$ (50,158)

These balances are interest-free, unsecured, payable on demand and have arisen from the transactions referred to above.

	2007	2006
Promissory note payable to the Corporation of the Town of Midland, bearing interest at the Government of Canada 10 year bond rate updated annually, unsecured with no specific terms of repayment	$ (1,122,519)	$ (1,122,519)

The shareholder has indicated that they will not request repayment of this balance within the next fiscal year. Consequently, this amount has been classified as long-term debt in the accompanying financial statements.

6. Employee Future Benefits

An actuarial report was performed and dated January 15, 2007. The actuarial valuation was performed on the post-retirement obligations sponsored by Midland Power Utility Corporation as at December 31, 2006. The next actuarial valuation should be performed by December 31, 2009.

During 2003 the corporation discontinued its post-retirement life insurance, dental and health benefits to all employees. As at December 31, 2007, there are only seven (2006 - seven) retirees who retain the post-retirement life insurance benefit.

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

	2007	2006
Accrued benefit liability, beginning of year	**$ 131,225**	$ 120,855
Expense for the year	**(3,684)**	(3,063)
Change in post-retirement plan - (d) below	**-**	13,433
Projected accrued benefit obligation at December 31	**$ 127,541**	$ 131,225
Additional Disclosures:		
Unamortized actuarial gain (loss)	**$ -**	$ -

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 2.1% per annum.

(b) Interest (discount) rate
The obligation, as at December 31, 2007, of the present value of future liabilities was determined using an annual discount rate of 5.0%. This rate reflects the assumed long-term yield on quality bonds as at November 2006.

(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 increased in 2006 over the 2003 valuation mainly as a result of a lower discount rate being used.

7. Other Long-Term Liabilities

	2007	2006
Hydro One Low Voltage Charges	**$ 52,884**	$ 302,544

The above amount represents the long-term portion of amounts owing to Hydro One for low voltage charges. The total amount owing is $302,544, of which $249,660 (2006 - $249,660) has been included in accounts payable and accrued liabilities as it is due to be repaid within one year. Refer to Note 3 (vii) for further information.

8. 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 380,000 active and retired members and approximately 910 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, 2007. The results of this valuation disclosed total actuarial liabilities of $46,830 million in respect of benefits accrued for service with actuarial assets at that date of $46,912 million, indicating an actuarial surplus of $82 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 6.5% for employees earning up to $43,700 and 9.6% thereafter. The amount contributed to OMERS for 2007 was $121,494 (2006 - $112,022).

9. Credit Facility

The corporation has a line of credit with an authorized limit of $3,000,000 available under a credit facility agreement with a Canadian chartered bank. Interest on advances is calculated using the bank's prime rate and are payable monthly. As at December 31, 2007 the corporation had drawn a balance of $NIL 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 10). As a result, the corporation's access to the $3,000,000 credit facility mentioned above is limited to

$1,904,270.

10. 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 proceedings 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. Subsequent to the year end, 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. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs’ situation may be distinguishable from that of Consumers Gas.

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.

(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.

(iii)The corporation has been named in a legal action for which the final outcome cannot be determined at this time. It is management's opinion that there will be no material uninsured liability arising from this claim. Therefore, no provision has been made for this claim in these financial statements.

December 31, 2007

11. 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. As at December 31, 2007, the corporation has not been made aware of any assessments for losses.

12. 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:

		2007	2006
1,000	Common shares	$ 6,880,984	$ 6,880,984

13. Net Service Revenue

	2007	2006
Service revenue	$ 125,651	$ 144,456
Service costs	(67,151)	(86,679)
Net service revenue	$ 58,500	$ 57,777

14. Other Revenue

	2007	2006
Late payment charges	$ 8,121	$ 13,730
Interest earned	74,750	62,682
Pole rental	29,674	34,926
Office rental	51,987	53,593
Carrying charges on regulatory balances	22,059	51,430
Gain on disposal	36,734	1,040
Other	95,587	82,975
	$ 318,912	$ 300,376

December 31, 2007

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

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

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

	2007	2006
Income before provision for PILs	$ **831,967**	$ 778,717
Prior year's tax loss	**-**	(209,827)
Net decrease in regulatory assets	**972,015**	765,973
Capital tax included in tax provision	**-**	(4,000)
Amortization expense in excess of capital cost allowance	**(45,654)**	91,603
Other items	**(37,997)**	12,926
Income for tax purposes	$ **1,720,331**	$ 1,435,392
Statutory Canadian federal and provincial tax rate	**34.12%**	34.49%
Provision for PILs	$ **587,000**	$ 496,000
Capital tax	**-**	4,000
Total provision	$ **587,000**	$ 500,000

(b) Future Taxes

Future income taxes have not been recognized in these financial statements. Section 3465 of the CICA Handbook does not require rate regulated enterprises to recognize future income taxes if future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers.

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

	2007	2006
Current:		
Regulatory assets net of liabilities	$ **(6,500)**	$ (358,000)
Long-Term:		
Employee future benefits	$ **46,000**	$ 47,000
Property, plant and equipment	**74,000**	100,500
	$ **120,000**	$ 147,500
Net future income tax asset (liability)	$ **113,500**	$ (210,500)

A future income tax recovery of $324,000 (2006 - $237,000) has not been reflected in the provision for PILs.

December 31, 2007

16. Statement of Cash Flows

		2007		2006
Interest paid	**$**	**53,821**	$	55,416
Interest received	**$**	**74,750**	$	62,682
PILs paid (net of amounts received)	**$**	**934,645**	$	(3,586)

17. Risk Management for Fair Value of Financial Assets and Liabilities

The corporation is not exposed to significant interest rate risk as a result of the short-term maturity of its monetary current assets and current liabilities.

The carrying value of cash, accounts receivable, unbilled revenue and accounts payable and accrued liabilities approximate their fair value due to the immediate or short-term maturity of these financial instruments.

The fair value of the corporation's promissory note payable to the shareholder is not readily determinable due to the related party nature and terms.

Financial assets held by the corporation expose it to credit risk. Under the corporation's credit facility (Note 9), the corporation may have short-term borrowings for working capital purposes. These borrowings would expose the corporation to fluctuations in the bank's prime rate. As at December 31, 2007, there were no other significant concentrations of credit risk with respect to any class of financial assets.

December 31, 2007

18. Ontario Price Credit Rebates

During the year ended December 31, 2007 the corporation received OPC Rebates pertaining to consumption for the period beginning April 1, 2006 - July 31, 2007. These rebates totalling $170,656 (2006 - $838,966) were recognized as a reduction in the cost of power purchased.

19. Change in Accounting Policy

On January 1, 2007, the corporation retroactively adopted, without restatement of prior periods, CICA Handbook Section 3861, "Financial Instruments - Disclosure and Presentation" and Section 3855, "Financial Instruments - Recognition and Measurement". These new Handbook Sections provide comprehensive requirements for the recognition and measurement of financial instruments. Under these new standards, 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 transitional provisions require these new standards to be adopted retroactively, without restatement of prior years. As such, the 2006 amounts have not been restated.

The adoption of these new standards had no material impact on the corporation's statement of operations.

Pro Forma Statements (2008)

Throughout this Application tables will be provided showing the USoA Numbers from the APH assembled into Account Groupings with an alternate numbering system used for presentation purposes only. Within the Account Groupings, the USoA Numbers and Account Descriptions are provided. The Account Groupings are as follows:

Balance Sheet Accounts
1050-Current Assets
1100-Inventory
1150-Non-Current Assets
1200-Other Assets & Deferred Charges
1450-Distribution Plant
1500-General Plant
1550-Other Capital Assets
1600-Accumulated Amortization
1650-Current Liabilities
1700-Non-Current Liabilities
1800-Long-Term Debt
1850-Shareholders' Equity

Income Statement Accounts
3000-Sales of Electricity
3050-Revenues from Services - Distribution
3100- Other Operating Revenues
3150-Other Income & Deductions
3200-Investment Income
3350-Power Supply Expenses
3500-Distribution Expenses – Operation
3550-Distribution Expenses – Maintenance
3650-Billing & Collecting
3700-Community Relations
3800-Administrative & General Expenses
3850-Amortization Expense
3900-Interest Expense
3950-Taxes Other than Income Taxes
4000-Income Taxes
4100-Extraordinary & Other Items

For example, under Account Grouping “3000- Sales of Electricity” the USoA Numbers and Descriptions included in this grouping are as follows:

3000-Sales of Electricity
4006-Residential Energy Sales
4025-Street Lighting Energy Sales
4030-Sentinel Lighting Energy Sales
4035-General Energy Sales
4062-Billed WMS
4066-Billed NW
4068-Billed CN
4075-Billed LV

The Pro Forma financial statements for the years 2008 and 2009 (next Schedule) are provided with this format and include the detailed USoA numbering system.

On the pages following this page are copies of the Pro Forma 2008 Projections.

Table 11 2008 PRO FORMA Balance Sheet

Account Description	Total
1050-Current Assets	
1005-Cash	179,160.72
1010-Cash Advances and Working Funds	300.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	-
1070-Current Investment	-
1100-Customer Accounts Receivable	1,147,762.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	88,563.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	63,959.00
1110-Other Accounts Receivable	33,687.00
1120-Accrued Utility Revenues	2,070,115.00
1130-Accumulated Provision for Uncollectible Accounts--Credit	(80,000.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1180-Prepayments	86,861.00
1190-Miscellaneous Current and Accrued Assets	(1,104.00)
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**3,589,303.72**
1100-Inventory	
1330-Plant Materials and Operating Supplies	272,602.00
1305-Fuel Stock	-
1350-Other Materials and Supplies	10,470.00
1100-Inventory Total	**283,072.00**
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1410-Other Special or Collateral Funds	-
1460-Other Non-Current Assets	1,260,000.00
1150-Non-Current Assets Total	**1,260,000.00**
1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	49,595.86
1518-RCVARetail	(8,604.52)
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	-
1550-LV Variance Account	120,212.67
1555-Smart Meters Capital Variance Account	(15,064.67)
1556-Smart Meters OM&A Variance Account	-
1562-Deferred Payments in Lieu of Taxes	(444,308.62)
1563-Deferred Payments in Lieu of Taxes contra	444,308.62
1565-Conservation and Demand Management Expenditures and Recoveries	92.20
1566-CDM Contra Account	-
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(389,379.66)

Account Description	Total
1582-RSVAONE-TIME	15,791.89
1584-RSVANW	275,760.88
1586-RSVACN	(1,013,169.15)
1588-RSVAPOWER	662,972.99
1590-Recovery of Regulatory Asset Balances	107,914.17
1200-Other Assets and Deferred Charges Total	**(193,877.35)**
1450-Distribution Plant	
1805-Land	365,297.97
1806-Land Rights	32,555.43
1808-Buildings and Fixtures	939,699.23
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	3,021,545.93
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	3,481,015.56
1835-Overhead Conductors and Devices	1,742,432.46
1840-Underground Conduit	-
1845-Underground Conductors and Devices	3,004,285.13
1850-Line Transformers	2,929,662.58
1855-Services	170,076.02
1860-Meters	1,030,781.92
1875-Street Lighting and Signal Systems	2,407.32
1450-Distribution Plant Total	**16,719,759.55**
1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1915-Office Furniture and Equipment	246,272.64
1920-Computer Equipment - Hardware	401,887.10
1925-Computer Software	293,858.12
1930-Transportation Equipment	863,672.66
1935-Stores Equipment	8,609.78
1940-Tools, Shop and Garage Equipment	252,199.46
1945-Measurement and Testing Equipment	2,634.03
1950-Power Operated Equipment	-
1955-Communication Equipment	131,712.74
1960-Miscellaneous Equipment	19,219.52
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	365,803.07
1500-General Plant Total	**2,585,869.12**
1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1995-Contributions and Grants - Credit	(759,809.52)
1875-Street Lighting	-
1550-Other Capital Assets Total	**(759,809.52)**

Account Description	Total
1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(10,024,318.59)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(10,024,318.59)**
Total Assets	**13,459,998.93**
1650-Current Liabilities	
2205-Accounts Payable	1,071,899.00
2208-Customer Credit Balances	266,280.00
2210-Current Portion of Customer Deposits	397,998.00
2220-Miscellaneous Current and Accrued Liabilities	371,789.00
2240-Accounts Payable to Associated Companies	-
2250-Debt Retirement Charges(DRC) Payable	123,282.00
2252-Transmission Charges Payable	-
2256-IESO Payable	1,263,840.00
2260-Current portion of Long Term Debt	-
2268-Accrued interest on LTD	44,789.00
2290-Commodity Taxes	16,953.00
2292-Payroll Deductions / Expenses Payable	17,334.00
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**3,574,164.00**
1700-Non-Current Liabilities	
2306-Employee Future Benefits	127,541.00
2310-Vested Sick Leave Liability	-
2320-Other Miscellaneous Non-Current Liabilities	4,263.00
2335-Long Term Customer Deposits	161,990.00
2340-Collateral funds liability	-
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	178,481.00
1700-Non-Current Liabilities Total	**472,275.00**
1800-Long-Term Debt	
2505-Debentures Ourstanding - Long Term Portion	1,122,519.00
2550-Advances from Associated Companies	-
1800-Long-Term Debt Total	**1,122,519.00**
1850-Shareholders' Equity	
3005-Common Shares Issued	6,881,984.00
3010-Contributed Surplus	-
3022-Development charges transferred	-
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	1,344,287.72
3046-Balance Transferred From Income	364,769.21
3049-Dividends Payable-Common Shares	(300,000.00)
1850-Shareholders' Equity Total	**8,291,040.93**
Total Liabilities & Shareholder's Equity	**13,459,998.93**
Balance Sheet Total	(0.00)

1

Table 12 2008 PRO FORMA Statement of Income

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	2,881,528.74
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	67,980.30
4030-Sentinel Lighting Energy Sales	925.75
4035-General Energy Sales	9,972,626.03
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	1,470,146.37
4066-Billed NW	792,131.35
4068-Billed CN	1,451,413.24
4075-Billed LV	268,609.48
3000-Sales of Electricity Total	**16,905,361.25**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	2,708,722.89
4082-Retail Services Revenues	-
4084-Service Transaction Requests (STR) Revenues	-
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**2,708,722.89**
3100-Other Operating Revenues	
4210-Rent from Electric Property	82,480.80
4220-Other Electric Revenues	-
4225-Late Payment Charges	10,000.00
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	91,625.00
3100-Other Operating Revenues Total	**184,105.80**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	82,000.00
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(60,800.00)
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenues of Non-Utility Operations	73,895.32
4380-Expenses of Non-Utility Operations	(21,000.00)
4390-Miscellaneous Non-Operating Income	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**74,095.32**

Account Description	Total
3200-Investment Income	
4405-Interest and Dividend Income	30,000.00
3200-Investment Income Total	**30,000.00**
3350-Power Supply Expenses	
4705-Power Purchased	12,923,060.82
4708-Charges-WMS	1,233,025.99
4710-Cost of Power Adjustments	-
4714-Charges-NW	792,131.35
4715-System Control and Load Dispatching	-
4716-Charges-CN	1,451,413.24
4730-Rural Rate Assistance Expense	237,120.38
4750-LV Charges	268,609.48
3350-Power Supply Expenses Total	**16,905,361.25**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	253,600.00
5010-Load Dispatching	15,700.00
5012-Station Buildings and Fixtures Expense	62,800.00
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	8,400.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	16,400.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	-
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	-
5040-Underground Distribution Lines and Feeders - Operation Labour	-
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-
5055-Underground Distribution Transformers - Operation	-
5065-Meter Expense	11,600.00
5070-Customer Premises - Operation Labour	22,300.00
5075-Customer Premises - Materials and Expenses	2,100.00
5085-Miscellaneous Distribution Expense	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**392,900.00**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	64,500.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,000.00
5114-Maintenance of Distribution Station Equipment	1,700.00
5120-Maintenance of Poles, Towers and Fixtures	6,400.00
5125-Maintenance of Overhead Conductors and Devices	97,100.00
5130-Maintenance of Overhead Services	-
5135-Overhead Distribution Lines and Feeders - Right of Way	29,300.00
5145-Maintenance of Underground Conduit	-

Account Description	Total
5150-Maintenance of Underground Conductors and Devices	34,100.00
5155-Maintenance of Underground Services	-
5160-Maintenance of Line Transformers	10,100.00
5175-Maintenance of Meters	82,000.00
3550-Distribution Expenses - Maintenance Total	**338,200.00**
3650-Billing and Collecting	
5305-Supervision	-
5310-Meter Reading Expense	96,000.00
5315-Customer Billing	176,900.00
5320-Collecting	66,700.00
5325-Collecting- Cash Over and Short	200.00
5330-Collection Charges	600.00
5335-Bad Debt Expense	80,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**420,400.00**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	5,700.00
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous customer accounts expenses	-
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**5,700.00**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,600.00
5610-Management Salaries and Expenses	284,000.00
5615-General Administrative Salaries and Expenses	66,400.00
5620-Office Supplies and Expenses	105,800.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	73,200.00
5635-Property Insurance	21,000.00
5640-Injuries and Damages	21,100.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	23,700.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	28,500.00
5670-Rent	-
5675-Maintenance of General Plant	88,700.00
5680-ESA fees	4,600.00
3800-Administrative and General Expenses Total	**744,600.00**

Account Description	Total
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	622,181.32
3850-Amortization Expense Total	**622,181.32**
3900-Interest Expense	
6005-Interest on Long Term Debt	44,789.00
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	16,648.47
6042-Allowance For Other Funds Used During Construction	-
3900-Interest Expense Total	**61,437.47**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	32,900.00
3950-Taxes Other Than Income Taxes Total	**32,900.00**
4000-Income Taxes	
6110-Income Taxes	13,836.00
6115-Provision for Future Income Taxes	-
4000-Income Taxes Total	**13,836.00**
4100-Extraordinary & Other Items	
6205-Donations	-
6215-Penalties	-
5706-Amortization Street Lighting	-
6310-Extraordinary Deductions	-
4100-Extraordinary & Other Items Total	**-**
(Net Income)/Loss	**(364,769.21)**

Pro Forma Statements (2009)

On the pages following this page are copies of the Pro Forma 2008 Projections.

1 **Table 13 2009 PRO FORMA Balance Sheet**

Account Description	Total
1050-Current Assets	
1005-Cash	1,048,755.75
1010-Cash Advances and Working Funds	300.00
1020-Interest Special Deposits	-
1040-Other Special Deposits	-
1070-Current Investment	-
1100-Customer Accounts Receivable	300.00
1102-Accounts Receivable - Services	-
1104-Accounts Receivable - Recoverable Work	88,563.00
1105-Accounts Receivable - Merchandise, Jobbing, etc.	63,959.00
1110-Other Accounts Receivable	33,687.00
1120-Accrued Utility Revenues	2,070,115.00
1130-Accumulated Provision for Uncollectible Accounts--Credit	(80,000.00)
1140-Interest and Dividends Receivable	-
1150-Rents Receivable	-
1180-Prepayments	88,861.00
1190-Miscellaneous Current and Accrued Assets	(1,104.00)
1200-Accounts Receivable from Associated Companies	-
1210-Notes Receivable from Associated Companies	-
1050-Current Assets Total	**3,313,436.75**
1100-Inventory	
1330-Plant Materials and Operating Supplies	272,602.00
1305-Fuel Stock	-
1350-Other Materials and Supplies	10,470.00
1100-Inventory Total	**283,072.00**
1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	-
1410-Other Special or Collateral Funds	-
1460-Other Non-Current Assets	1,260,000.00
1150-Non-Current Assets Total	**1,260,000.00**
1200-Other Assets and Deferred Charges	
1508-Other Regulatory Assets	51,238.79
1518-RCVARetail	(8,861.57)
1525-Miscellaneous Deferred Debits	-
1548-RCVASTR	-
1550-LV Variance Account	124,019.13
1555-Smart Meters Capital Variance Account	(97,714.64)
1556-Smart Meters OM&A Variance Account	-
1562-Deferred Payments in Lieu of Taxes	(456,439.83)
1563-Deferred Payments in Lieu of Taxes contra	456,439.83
1565-Conservation and Demand Management Expenditures and Recoveries	92.20
1566-CDM Contra Account	0.26
1570-Qualifying Transition Costs	-
1571-Pre-market Opening Energy Variance	-
1572-Extraordinary Event Costs	-
1580-RSVAWMS	(401,912.32)
1582-RSVAONE-TIME	16,247.69

Account Description	Total
1584-RSVANW	284,414.83
1586-RSVACN	(1,044,847.24)
1588-RSVAPOWER	683,074.72
1590-Recovery of Regulatory Asset Balances	111,556.21
1200-Other Assets and Deferred Charges Total	**(282,691.93)**
1450-Distribution Plant	
1805-Land	365,297.97
1806-Land Rights	32,555.43
1808-Buildings and Fixtures	974,699.23
1810-Leasehold Improvements	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	4,067,345.93
1825-Storage Battery Equipment	-
1830-Poles, Towers and Fixtures	3,858,155.56
1835-Overhead Conductors and Devices	1,907,692.46
1840-Underground Conduit	-
1845-Underground Conductors and Devices	3,382,065.13
1850-Line Transformers	3,307,802.58
1855-Services	268,956.02
1860-Meters	1,040,781.92
1875-Street Lighting and Signal Systems	2,407.32
1450-Distribution Plant Total	**19,207,759.55**
1500-General Plant	
1905-Land	-
1906-Land Rights	-
1908-Buildings and Fixtures	-
1915-Office Furniture and Equipment	246,272.64
1920-Computer Equipment - Hardware	420,927.10
1925-Computer Software	313,858.12
1930-Transportation Equipment	1,044,592.30
1935-Stores Equipment	8,609.78
1940-Tools, Shop and Garage Equipment	262,199.46
1945-Measurement and Testing Equipment	2,634.03
1950-Power Operated Equipment	-
1955-Communication Equipment	131,712.74
1960-Miscellaneous Equipment	19,219.52
1970-Load Management Controls - Customer Premises	-
1980-System Supervisory Equipment	465,803.07
1500-General Plant Total	**2,915,828.76**
1550-Other Capital Assets	
2055-Construction Work in Progress--Electric	-
2060-Electric Plant Acquisition Adjustment	-
2070-Other Utility Plant	-
1995-Contributions and Grants - Credit	(985,009.52)
1875-Street Lighting	-
1550-Other Capital Assets Total	**(985,009.52)**

Account Description	Total
1600-Accumulated Amortization	
2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(10,653,962.54)
2160-Accumulated Amortization of Other Utility Plant	-
1600-Accumulated Amortization Total	**(10,653,962.54)**
Total Assets	**15,058,433.07**
1650-Current Liabilities	
2205-Accounts Payable	1,017,889.00
2208-Customer Credit Balances	266,280.00
2210-Current Portion of Customer Deposits	397,998.00
2220-Miscellaneous Current and Accrued Liabilities	371,789.00
2225-Loans payable	-
2240-Accounts Payable to Associated Companies	-
2250-Debt Retirement Charges(DRC) Payable	123,282.00
2252-Transmission Charges Payable	-
2256-IESO Payable	1,263,840.00
2260-Current portion of Long Term Debt	-
2268-Accrued interest on LTD	44,789.00
2290-Commodity Taxes	16,953.00
2292-Payroll Deductions / Expenses Payable	17,334.00
2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-
2296-Future Income Taxes - Current	-
1650-Current Liabilities Total	**3,520,154.00**
1700-Non-Current Liabilities	
2306-Employee Future Benefits	127,541.00
2310-Vested Sick Leave Liability	-
2320-Other Miscellaneous Non-Current Liabilities	4,263.00
2335-Long Term Customer Deposits	161,990.00
2340-Collateral funds liability	-
2350-Future Income Tax - Non-Current	-
2405-Other Regulatory Liabilities	-
2425-Other Deferred Credits	178,481.00
1700-Non-Current Liabilities Total	**472,275.00**
1800-Long-Term Debt	
2505-Debentures Outstanding - Long term portion	1,122,519.00
2520-Other Deferred Credits	2,000,000.00
1800-Long-Term Debt Total	**3,122,519.00**
1850-Shareholders' Equity	
3005-Common Shares Issued	6,881,984.00
3010-Contributed Surplus	-
3022-Development charges transferred	-
3030-Miscellaneous Paid-In Capital	-
3045-Unappropriated Retained Earnings	1,409,056.93
3046-Balance Transferred From Income	(47,555.86)
3049-Dividends Payable-Common Shares	(300,000.00)
1850-Shareholders' Equity Total	**7,943,485.07**
Total Liabilities & Shareholder's Equity	**15,058,433.07**
Balance Sheet Total	(0.00)

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Table 14 2009 PRO FORMA Statement of Income

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	2,890,308.26
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	69,412.75
4030-Sentinel Lighting Energy Sales	925.75
4035-General Energy Sales	9,728,400.94
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	1,443,363.60
4066-Billed NW	778,571.81
4068-Billed CN	1,427,035.96
4075-Billed LV	339,515.32
3000-Sales of Electricity Total	**16,677,534.40**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	2,701,224.01
4082-Retail Services Revenues	-
4084-Service Transaction Requests (STR) Revenues	-
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**2,701,224.01**
3100-Other Operating Revenues	
4210-Rent from Electric Property	82,480.80
4220-Other Electric Revenues	-
4225-Late Payment Charges	10,000.00
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	91,625.00
3100-Other Operating Revenues Total	**184,105.80**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	82,000.00
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(60,800.00)
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenue of Non-Utility Operations	49,000.00
4380-Expenses of Non-Utility Operations	(21,000.00)
4390-Miscellaneous Non-Operating Income	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**49,200.00**
3200-Investment Income	
4405-Interest and Dividend Income	10,000.00
3200-Investment Income Total	**10,000.00**
3350-Power Supply Expenses	
4705-Power Purchased	12,689,047.70
4708-Charges-WMS	1,210,698.13

Account Description	Total
4710-Cost of Power Adjustments	-
4714-Charges-NW	778,571.81
4715-System Control and Load Dispatching	-
4716-Charges-CN	1,427,035.96
4730-Rural Rate Assistance Expense	232,665.47
4750-LV Charges	339,515.32
3350-Power Supply Expenses Total	**16,677,534.40**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	314,900.00
5010-Load Dispatching	16,000.00
5012-Station Buildings and Fixtures Expense	64,000.00
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	8,200.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	17,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	-
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	-
5040-Underground Distribution Lines and Feeders - Operation Labour	-
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-
5055-Underground Distribution Transformers - Operation	-
5065-Meter Expense	11,400.00
5070-Customer Premises - Operation Labour	22,100.00
5075-Customer Premises - Materials and Expenses	2,100.00
5085-Miscellaneous Distribution Expense	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**455,700.00**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	77,200.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,400.00
5114-Maintenance of Distribution Station Equipment	1,600.00
5120-Maintenance of Poles, Towers and Fixtures	6,600.00
5125-Maintenance of Overhead Conductors and Devices	95,900.00
5130-Maintenance of Overhead Services	-
5135-Overhead Distribution Lines and Feeders - Right of Way	29,300.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	33,800.00
5155-Maintenance of Underground Services	-
5160-Maintenance of Line Transformers	9,900.00
5175-Maintenance of Meters	86,200.00
3550-Distribution Expenses - Maintenance Total	**353,900.00**
3650-Billing and Collecting	
5305-Supervision	-
5310-Meter Reading Expense	96,000.00
5315-Customer Billing	190,300.00
5320-Collecting	68,700.00
5325-Collecting- Cash Over and Short	200.00

Account Description	Total
5330-Collection Charges	600.00
5335-Bad Debt Expense	80,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**435,800.00**
3700-Community Relations	
5405-Supervision	-
5410-Community Relations - Sundry	5,600.00
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous customer accounts expenses	-
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**5,600.00**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,600.00
5610-Management Salaries and Expenses	285,900.00
5615-General Administrative Salaries and Expenses	70,400.00
5620-Office Supplies and Expenses	107,800.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	75,400.00
5635-Property Insurance	21,600.00
5640-Injuries and Damages	21,700.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	73,700.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	28,500.00
5670-Rent	-
5675-Maintenance of General Plant	90,600.00
5680-ESA Fees	4,700.00
3800-Administrative and General Expenses Total	**807,900.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	735,424.31
3850-Amortization Expense Total	**735,424.31**
3900-Interest Expense	
6005-Interest on Long Term Debt	144,788.52
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	18,772.84
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**163,561.36**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	34,200.00
3950-Taxes Other Than Income Taxes Total	**34,200.00**
4000-Income Taxes	
6110-Income Taxes	-
6115-Provision for Future Income Taxes	

Account Description	Total
4000-Income Taxes Total	**-**
4100-Extraordinary & Other Items	
6205-Donations	-
6215-Penalties	-
5706-Amortization Street Lighting	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**-**
(Net Income)/Loss	**47,555.86**

Reconciliation between Financial Statements and Financial Results Filed

MPUC has reconciled the RRR Filing with the Audited Financial Statements and has found no differences.

Proposed Accounting Treatment for long lived assets

MPUC's accounting procedures are consistent with the Canadian GAAP and the Board's Accounting Procedures Handbook. MPUC does not capture the cost of funding capital projects (AFUDC) and accordingly, has not reflected any amounts concerning this practice in this rate application. MPUC will follow the Board's Uniform System of Accounts should the need arise using the prescribed interest rate in effect at that time.

The following information relates to the accounting treatment of long lived assets. Long-lived assets include property, plant and equipment and intangibles that are subject to amortization.

Property, plant and equipment are stated at cost. Gains or losses on disposition of such assets are credited or charged to "Other income" in the Statement of Income.

Compliance with the Uniform System of Accounts

MPUC has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the USofA in the preparation of this Application.

Accounting Orders

MPUC is not aware of any accounting orders at this time.

To assist in the transition to International Financial Reporting Standards ("IFRS"), MPUC is aware that the Board has created a consultation regarding the Transition of Regulatory Accounting to IFRS (the "IFRS Consultation"). Generally Accepted Accounting Principles in Canada will be transitioned to IFRS effective January 1, 2011.

The IFRS Consultation will provide an opportunity for Board staff to work with interested industry participants on an informal basis with a view to identifying issues associated with this transition as well as suggestions for how those issues might be addressed. This will provide input to Board staff's work to develop a transition plan for the Board's regulatory accounting instruments and processes.

Annual Report

Not applicable.

MPUC's audited financial statements for the 2006 and 2007 years are included at Exhibit 1, Tab 3, Schedule 1 and 2.

Prospectus, information and recent share issue update

Not Applicable.

Extraordinary Events

Extraordinary Circumstances

Not Applicable.

EXHIBIT 2 - RATE BASE

Overview

Rate Base Overview

The Rate Base Summary table is shown in Exhibit 2, Tab 1, Schedule 2. This table provides a projection of MPUC's rate base for both the Bridge Year (2008) and the Test Year (2009). Comparisons are also provided for the 2006 EDR and 2006 actual data and 2007 actual data.

MPUC's forecast rate base for the test year is $12,318,654. The rate base underlying the test year revenue requirements includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

Gross Asset – Property, Plant & Equipment and Accumulated Amortization

The bridge and test year's gross asset balance reflects the capital expenditure programs forecast for both years. Comparisons are also provided for the 2006 EDR and 2006 actual data and 2007 actual data. These programs are described in detail in the MPUC's written evidence at Exhibit 2, Tab 2. The justification for capital projects in excess of 1% of the net fixed assets are filed also at Exhibit 2, Tab 3, Schedule 1 and 2 along with a summary of those projects less than 1% of the net fixed assets.

Capital Budget

The Capital Budget for both the bridge year and test year is included in Exhibit 2, Tab 3, Schedule 1 and 2. Comparisons are also provided for the 2006 EDR, the 2006 actual data and 2007 actual data. Exhibit 2 provides all the relevant information pertaining to the Capital Program at MPUC. The review for capital projects in excess of 1% of the net fixed assets are also included along with a summary of those projects less than 1% of the net fixed assets.

MPUC has six substations, four of which are over 50 years old. Due to the aging infrastructure, MPUC determined that a plan needed to be implemented dealing with the replacement of the substations to ensure the safety and reliability of the infrastructure was maintained, and in 2006, Rondar Engineering completed an assessment of the substation infrastructure. Rondar has been completing the maintenance on MPUC substations over the past 10 years and is familiar with the transformer condition and breaker relay systems of the substations. Having completed the regular maintenance on the substations, it made sense to have Rondar do a thorough investigation and provide a report giving specifications and system requirements. Rondar has a proven record with MPUC. They know the equipment and are familiar with MPUC's distribution system whereas a new contractor would have a learning curve, which may jeopardize the safety and reliability of the substations. A new contractor would not have a proven record with MPUC. MPUC's current plan is to replace one substation per year in each of the years 2007, 2008, 2009, 2010 and in 2011 the two newer stations – Montreal and Queen would be combined. The Scott Street substation was completed in 2007. Brandon is slated for replacement in 2008 with Fourth Street following in 2009.

In addition to the substation projects, in 2007 MPUC determined what additional capital projects would be slated for the 2008 year and obtained quotes from three contractors. These quotes were compared to the cost of completing the projects using in-house resources. This process served as the basis upon which the 2008 and 2009 capital projects were budgeted. It was found that in-house resources would provide the best economies to MPUC and accordingly, the projects in 2008 and 2009 were budgeted using MPUC resources in place of outside contractors.

Allowance for Working Capital

Exhibit 2, Tab 4, Schedule 1 provides a summary of working capital for the 2006 EDR, 2006 actual year, 2007 actual year, 2008 Bridge Year and the 2009 Test Year. The calculation of working capital by USoA number for the 2009 Test Year is included in Exhibit 2, Tab 4, Schedule 2. The 2009 Working Capital Allowance is $2,815,595 and a calculation of the 2009 Working Capital is provided on the page following this page. This calculation shows that the total OM&A Expenses are $2,093,100 and this amount coupled with the Power Supply Expense of $16,677,534 totals the expense for working capital of $18,770,634. Working capital is then calculated as 15% of the Total Expenses for Working Capital or $2,815,595. The calculation of the Power Supply Expense is included in Exhibit 2, Tab 4, Schedule 3.

The 2009 Working Capital Allowance is provided below.

Table 15 Working Capital Allowance 2009

Eligible Distribution Expenses:		
3500-Distribution Expenses - Operation		455,700
3550-Distribution Expenses - Maintenance		353,900
3650-Billing and Collecting		435,800
3700-Community Relations		5,600
3800-Administrative and General Expenses		807,900
3950-Taxes Other Than Income Taxes		34,200
Total Eligible Distribution Expenses		2,093,100
3350-Power Supply Expenses		16,677,534
Total Expenses for Working Capital		**18,770,634**
Working Capital Allowance	**15.0%**	**2,815,595**

Rate Base Summary Table

The Rate Base Summary table below provides a listing of the Net Capital Assets in Service and Working Capital for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years.

Table 16 Rate Base Summary

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Net Capital Assets in Service:					
Opening Balance		5,729,993	5,735,722	6,630,550	8,521,501
Ending Balance		5,735,722	6,630,550	8,521,501	10,484,616
Average Balance	5,251,869	5,732,858	6,183,136	7,576,025	9,503,058
Working Capital Allowance	2,662,646	2,670,771	2,791,219	2,826,009	2,815,595
Total Rate Base	**7,914,515**	**8,403,628**	**8,974,355**	**10,402,034**	**12,318,654**
Expenses for Working Capital					
Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	272,722	374,509	352,987	392,900	455,700
3550-Distribution Expenses - Maintenance	306,118	336,041	283,582	338,200	353,900
3650-Billing and Collecting	412,100	379,313	451,821	420,400	435,800
3700-Community Relations	15,581	23,774	15,073	5,700	5,600
3800-Administrative and General Expenses	673,755	655,050	650,232	744,600	807,900
3950-Taxes Other Than Income Taxes	28,420	34,495	31,306	32,900	34,200
Total Eligible Distribution Expenses	1,708,695	1,803,182	1,785,000	1,934,700	2,093,100
3350-Power Supply Expenses	16,042,281	16,001,955	16,823,128	16,905,361	16,677,534
Total Expenses for Working Capital	17,750,976	17,805,137	18,608,129	18,840,061	18,770,634
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,662,646**	**2,670,771**	**2,791,219**	**2,826,009**	**2,815,595**

Variance Analysis on Rate Base Table

Included on the next page is the Variance Analysis on Rate Base Table which provides a listing of the Net Capital Assets in Service and Working Capital for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years along with the year over year variances. Net Capital Assets in Service are calculated by taking an average of the opening and closing balances in each year. The Materiality Threshold is based on 1% of Net Fixed Assets for the calculation of Total Rate Base . Working Capital Allowance is calculated at 15% of the Eligible Distribution Expenses plus Power Supply Expenses. The Materiality Threshold is based on 1% of the total of OM&A Expenses and Amortization for the calculation of the Working Capital Allowance. Explanations for variances that exceed the materiality thresholds as prescribed in the Filing Guidelines are set out in the following sections.

2006 Actual compared to 2006 Approved EDR

The 2006 Actual Year Rate Base is $489,113 or 6.2% higher than the 2006 Approved Rate Base. The difference can be attributed to the use of historic 2003 and 2004 data to establish the 2006 Approved Rate Base. Changes in capital expenditures during 2005 and 2006, and therefore rate base, are to be expected after 2 years (2005 and 2006) of capital expenditures.

2007 Actual compared to 2006 Actual

The 2007 Actual Year Rate Base is $570,727 or 6.8% higher than the 2006 Actual Year Rate Base. This variance is as a result of average capital expenditures in 2007 of $450,278 and an increase in the allowance for working capital of $120,449.

2008 Bridge compared to 2007 Actual

The 2008 Bridge Year Rate Base exceeds the 2007 Actual Year Rate Base by $1,427,679 or 15.9%. This variance is as a result of average capital expenditures of $1,392,889 and an increase in the allowance for working capital of $34,790.

2009 Test Year compared to 2008 Bridge

The 2009 Test Year Rate Base exceeds the 2008 Bridge Year Rate Base by $1,916,619 or 18.4%. Working capital will decrease by $10,414 while average capital expenditures in 2009 will increase by $1,927,033.

Table 17 Detailed Variance Analysis on Rate Base (2009 and 2008)

	Variances in excess of $85,215 are shown in bold				***Variances in excess of $66,305 are shown in bold***			
	2009 Projection	**2008 Projection**	**Var $**	**Var %**	**2008 Projection**	**2007 Actual**	**Var $**	**Var %**
Net Capital Assets in Service:								
Opening Balance	8,521,501	6,630,550	**1,890,951**	**28.5%**	6,630,550	5,735,722	**894,828**	**15.6%**
Ending Balance	10,484,616	8,521,501	**1,963,116**	**23.0%**	8,521,501	6,630,550	**1,890,951**	**28.5%**
Average Balance	9,503,058	7,576,025	**1,927,033**	**25.4%**	7,576,025	6,183,136	**1,392,889**	**22.5%**
Working Capital Allowance	2,815,595	2,826,009	-10,414	(0.4%)	2,826,009	2,791,219	34,790	1.2%
Total Rate Base	**12,318,654**	**10,402,034**	**1,916,619**	**18.4%**	**10,402,034**	**8,974,355**	**1,427,679**	**15.9%**

Expenses for Working Capital	***Variances in excess of $25,569 are shown in bold***				***Variances in excess of $23,089 are shown in bold***			
Eligible Distribution Expenses:								
3500-Distribution Expenses - Operation	455,700	392,900	**62,800**	**16.0%**	392,900	352,987	**39,913**	**11.3%**
3550-Distribution Expenses – Maintenance	353,900	338,200	15,700	4.6%	338,200	283,582	**54,618**	**19.3%**
3650-Billing and Collecting	435,800	420,400	15,400	3.7%	420,400	451,821	**-31,421**	**(7.0%)**
3700-Community Relations	5,600	5,700	-100	(1.8%)	5,700	15,073	-9,373	(62.2%)
3800-Administrative and General Expenses	807,900	744,600	**63,300**	**8.5%**	744,600	650,232	**94,368**	**14.5%**
3950-Taxes Other Than Income Taxes	34,200	32,900	1,300	4.0%	32,900	31,306	1,594	5.1%
Total Eligible Distribution Expenses	2,093,100	1,934,700	**158,400**	**8.2%**	1,934,700	1,785,000	**149,700**	**8.4%**
3350-Power Supply Expenses	16,677,534	16,905,361	**-227,827**	**(1.3%)**	16,905,361	16,823,128	**82,233**	**0.5%**
Total Expenses for Working Capital	18,770,634	18,840,061	**-69,427**	**(0.4%)**	18,840,061	18,608,129	**231,933**	**1.2%**
Working Capital factor	15.0%	15.0%			15.0%	15.0%		
Working Capital Allowance	**2,815,595**	**2,826,009**	**-10,414**	**(0.4%)**	**2,826,009**	**2,791,219**	**34,790**	**1.2%**

Table 18 Detailed Variance Analysis on Rate Base- (2007 and 2006)

	Variances in excess of $57,357 are shown in bold				***Variances in excess of $52,519 are shown in bold***			
Net Capital Assets in Service:	**2007 Actual**	**2006 Actual**	**Var $**	**Var %**	**2006 Actual**	**2006 EDR**	**Var $**	**Var %**
Opening Balance	5,735,722	5,729,993	5,729	0.1%	5,729,993	5,335,412	394,581	7.4%
Ending Balance	6,630,550	5,735,722	894,828	15.6%	5,735,722	5,168,325	567,397	11.0%
Average Balance	6,183,136	5,732,858	450,278	7.9%	5,732,858	5,251,869	480,989	9.2%
Working Capital Allowance	2,791,219	2,670,771	120,449	4.5%	2,670,771	2,662,646	8,124	0.3%
Total Rate Base	**8,974,355**	**8,403,628**	**570,727**	**6.8%**	**8,403,628**	**7,914,515**	**489,113**	**6.2%**

Expenses for Working Capital	***Variances in excess of $23,010 are shown in bold***				***Variances in excess of $21,447 are shown in bold***			
Eligible Distribution Expenses:	352,987	374,509	-21,521	(5.7%)	374,509	272,722	101,787	37.3%
3500-Distribution Expenses - Operation	283,582	336,041	-52,459	(15.6%)	336,041	306,118	29,923	9.8%
3550-Distribution Expenses – Maintenance	451,821	379,313	72,507	19.1%	379,313	412,100	-32,786	(8.0%)
3650-Billing and Collecting	15,073	23,774	-8,701	(36.6%)	23,774	15,581	8,193	52.6%
3700-Community Relations	650,232	655,050	-4,819	(0.7%)	655,050	673,755	-18,705	(2.8%)
3800-Administrative and General Expenses	31,306	34,495	-3,189	(9.2%)	34,495	28,420	6,075	21.4%
3950-Taxes Other Than Income Taxes	1,785,000	1,803,182	-18,182	(1.0%)	1,803,182	1,708,695	94,487	5.5%
Total Eligible Distribution Expenses	16,823,128	16,001,955	821,174	5.1%	16,001,955	16,042,281	-40,326	(0.3%)
3350-Power Supply Expenses	18,608,129	17,805,137	802,992	4.5%	17,805,137	17,750,976	54,161	0.3%
Total Expenses for Working Capital	15.0%	15.0%			15.0%	15.0%		
Working Capital factor	2,791,219	2,670,771	120,449	4.5%	**2,670,771**	**2,662,646**	**8,124**	**0.3%**

Fixed Assets

Overview and Fixed Asset Continuity Statements

This section provides an analysis on MPUC's Fixed Asset additions, retirements and other adjustments. The analysis starts with the 2006 EDR Balances and provides information on the 2005, 2006 and 2007 actual year additions, retirements and other adjustments, the 2008 Bridge Year additions and the 2009 Test Year additions and retirements. Exhibit 2, Tab 2, Schedule 3 sets out the analysis by APH USoA number for each of the years. Included in this analysis are costs attributed to the Capital Projects which are set out in Exhibit 2, Tab 3, Schedule 1. Reference is made in the USoA number analysis, where applicable, to the major Capital Projects and alternatively, is made where applicable, in the major Capital Projects to the USoA number analysis.

The major Capital Projects in Exhibit 2, Tab 3, Schedule 1 are numbered according to the year in which they occurred. For example, the first project in 2005 is the 44 kv Distribution System. This project is described as #2005-01 - 44kV Distribution System. The next Project would be described as #2005-02, etc. In 2006, the numbering system would be #2006-01, #2006-02, etc. and so on for each of the subsequent years. These Capital Projects are then broken down into costs per APH USoA numbers.

The materiality threshold has been set as 1% of net fixed assets. A calculation of the materiality thresholds is set out in Exhibit 2, Tab 2, Schedule 3. Those additions greater than 1% of net fixed assets have been explained in detail. Those additions less than 1% of net fixed assets have been summarized in each of the Exhibits mentioned above.

Contributed Capital: Customers request MPUC to complete work at their premises. MPUC assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in USoA Number 1995 – Contributed Capital. MPUC increases the asset account number and records the corresponding credit to Contributed

Capital Account #1995. Contributed Capital asset additions are identified by "CC" after the description of the addition on both Exhibit 2, Tab 2, Schedule 3 and Exhibit 2, Tab 3, Schedule 1.

As mentioned previously, in 2006 MPUC completed a substation study that provided an analysis of existing infrastructure and a plan for the replacement taking into consideration the potential for future growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old. Our current plan is to replace one substation per year starting in 2007. A copy of this study is included as Attachment to Exhibit 2, Tab 3, Schedule 1.

Fixed Asset Continuity Statements

Attached on the following pages is the Capital Asset Continuity Statements for the 2006 EDR, the 2006 Actual Year, the 2007 Actual Year, the 2008 Bridge Year and the 2009 Test Year.

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other *	Amortization	Balance
1805-Land					
Gross Assets	365,298				365,298
Accumulated Amortization					
Net Book Value	365,298				365,298
1806-Land Rights					
Gross Assets	32,555				32,555
Accumulated Amortization	-15,060			-0	-15,060
Net Book Value	17,495			-0	17,495
1808-Buildings and Fixtures					
Gross Assets	855,670	17,012	6,593		879,275
Accumulated Amortization	-236,926		-13,155	-41,481	-291,562
Net Book Value	618,744	17,012	-6,562	-41,481	587,714
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,040,689	60,010	36,679		1,137,378
Accumulated Amortization	-757,771		-12,035	-49,631	-819,437
Net Book Value	282,918	60,010	24,643	-49,631	317,941
1830-Poles, Towers and Fixtures					
Gross Assets	2,147,372	854,429	25,093		3,026,893
Accumulated Amortization	-1,295,265		-31,806	-207,179	-1,534,250
Net Book Value	852,107	854,429	-6,713	-207,179	1,492,643
1835-Overhead Conductors and Devices					
Gross Assets	1,424,965	56,803	1,230		1,482,998
Accumulated Amortization	-851,330		-20,881	-129,489	-1,001,700
Net Book Value	573,635	56,803	-19,651	-129,489	481,298
1840-Underground Conduit					
Gross Assets	1,436,491		-1,436,491		
Accumulated Amortization					
Net Book Value	1,436,491		-1,436,491		
1845-Underground Conductors and Devices					
Gross Assets	976,916	93,850	1,437,268		2,508,034
Accumulated Amortization	-1,369,793		-46,506	-199,889	-1,616,188
Net Book Value	-392,877	93,850	1,390,763	-199,889	891,847

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 EDR Approved	Variance to 2006 Actual Additions	Ret./Other *	Amortization	2006 Balance
1850-Line Transformers					
Gross Assets	2,152,009	104,149	51,402		2,307,560
Accumulated Amortization	-1,281,147		-34,639	-147,757	-1,463,543
Net Book Value	870,862	104,149	16,763	-147,757	844,017
1855-Services					
Gross Assets	778	21,020	-0		21,798
Accumulated Amortization				-1,961	-1,961
Net Book Value	778	21,020	-0	-1,961	19,837
1860-Meters					
Gross Assets	887,555	118,879	-2,569		1,003,864
Accumulated Amortization	-497,579		-14,350	-11,902	-523,831
Net Book Value	389,976	118,879	-16,919	-11,902	480,034
1875-Street Lighting and Signal Systems					
Gross Assets	2,596		-188		2,407
Accumulated Amortization				-2,596	-2,596
Net Book Value	2,596		-188	-2,596	-189
1915-Office Furniture and Equipment					
Gross Assets	220,937	5,544	11,044		237,525
Accumulated Amortization	-184,705		-3,750	-14,370	-202,825
Net Book Value	36,232	5,544	7,294	-14,370	34,700
1920-Computer Equipment - Hardware					
Gross Assets	349,742	13,250	11,294		374,286
Accumulated Amortization	-282,922		-13,876	-51,876	-348,674
Net Book Value	66,820	13,250	-2,582	-51,876	25,612
1925-Computer Software					
Gross Assets	63,109	45,403	25,076		133,588
Accumulated Amortization	-19,229		-6,311	-39,656	-65,196
Net Book Value	43,880	45,403	18,765	-39,656	68,392
1930-Transportation Equipment					
Gross Assets	712,216	260,034	-232,522		739,728
Accumulated Amortization	-684,348		244,814	-48,848	-488,381
Net Book Value	27,868	260,034	12,292	-48,848	251,347
1935-Stores Equipment					
Gross Assets	8,610				8,610
Accumulated Amortization	-7,796		-199	-246	-8,241
Net Book Value	814		-199	-246	369

Capital Asset Continuity Statements

* Asset retirements and other changes	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other *	Amortization	Balance
1940-Tools, Shop and Garage Equipment					
Gross Assets	171,059	8,859	5,956		185,874
Accumulated Amortization	-165,611		0	-65,006	-230,616
Net Book Value	5,448	8,859	5,956	-65,006	-44,742
1945-Measurement and Testing Equipment					
Gross Assets	2,634				2,634
Accumulated Amortization	-2,439			2,439	
Net Book Value	195			2,439	2,634
1955-Communication Equipment					
Gross Assets	131,413		300		131,713
Accumulated Amortization	-108,477		-6,988	39,393	-76,073
Net Book Value	22,936		-6,689	39,393	55,640
1960-Miscellaneous Equipment					
Gross Assets	18,335		885		19,220
Accumulated Amortization	-18,049		0	16,127	-1,922
Net Book Value	286		885	16,127	17,298
1980-System Supervisory Equipment					
Gross Assets	284,044	9,271	21,731		315,046
Accumulated Amortization	-125,598		-8,998	-49,098	-183,694
Net Book Value	158,446	9,271	12,733	-49,098	131,352
1995-Contributions and Grants - Credit					
Gross Assets	-212,621	-97,083	4,893		-304,812
Accumulated Amortization			-70,781	70,781	
Net Book Value	-212,621	-97,083	-65,889	70,781	-304,812
TOTAL					
Gross Assets	**13,072,370**	**1,571,429**	**-32,327**		**14,611,472**
Accumulated Amortization	**-7,904,045**		**-39,462**	**-932,243**	**-8,875,750**
Net Book Value	**5,168,325**	**1,571,429**	**-71,789**	**-932,243**	**5,735,722**

Capital Asset Continuity Statements

* Asset retirements and other changes	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1805-Land					
Gross Assets	365,298				365,298
Accumulated Amortization					
Net Book Value	365,298				365,298
1806-Land Rights					
Gross Assets	32,555				32,555
Accumulated Amortization	-15,060				-15,060
Net Book Value	17,495				17,495
1808-Buildings and Fixtures					
Gross Assets	879,275	37,224	-0		916,499
Accumulated Amortization	-291,562			-28,031	-319,592
Net Book Value	587,714	37,224	-0	-28,031	596,907
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,137,378	714,268			1,851,646
Accumulated Amortization	-819,437			-41,760	-861,198
Net Book Value	317,941	714,268		-41,760	990,448
1830-Poles, Towers and Fixtures					
Gross Assets	3,026,893	163,882			3,190,776
Accumulated Amortization	-1,534,250			-94,944	-1,629,194
Net Book Value	1,492,643	163,882		-94,944	1,561,582
1835-Overhead Conductors and Devices					
Gross Assets	1,482,998	105,474			1,588,472
Accumulated Amortization	-1,001,700			-46,517	-1,048,217
Net Book Value	481,298	105,474		-46,517	540,255
1840-Underground Conduit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1845-Underground Conductors and Devices					
Gross Assets	2,508,034	67,471			2,575,505
Accumulated Amortization	-1,616,188			-98,147	-1,714,334
Net Book Value	891,847	67,471		-98,147	861,171

Capital Asset Continuity Statements

* Asset retirements and other changes	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1850-Line Transformers					
Gross Assets	2,307,560	140,263			2,447,823
Accumulated Amortization	-1,463,543			-78,303	-1,541,845
Net Book Value	844,017	140,263		-78,303	905,977
1855-Services					
Gross Assets	21,798	46,599			68,396
Accumulated Amortization	-1,961			-1,742	-3,703
Net Book Value	19,837	46,599		-1,742	64,693
1860-Meters					
Gross Assets	1,003,864	18,818	0		1,022,682
Accumulated Amortization	-523,831			-34,720	-558,550
Net Book Value	480,034	18,818	0	-34,720	464,132
1875-Street Lighting and Signal Systems					
Gross Assets	2,407				2,407
Accumulated Amortization	-2,596			189	-2,407
Net Book Value	-189			189	
1915-Office Furniture and Equipment					
Gross Assets	237,525	8,748			246,273
Accumulated Amortization	-202,825			-6,121	-208,945
Net Book Value	34,700	8,748		-6,121	37,327
1920-Computer Equipment - Hardware					
Gross Assets	374,286	14,388			388,674
Accumulated Amortization	-348,674			-11,875	-360,549
Net Book Value	25,612	14,388		-11,875	28,125
1925-Computer Software					
Gross Assets	133,588	146,271			279,858
Accumulated Amortization	-65,196			-36,943	-102,139
Net Book Value	68,392	146,271		-36,943	177,720
1930-Transportation Equipment					
Gross Assets	739,728	151,987	-67,942		823,773
Accumulated Amortization	-488,381		67,942	-48,929	-469,368
Net Book Value	251,347	151,987		-48,929	354,405
1935-Stores Equipment					
Gross Assets	8,610				8,610
Accumulated Amortization	-8,241			-123	-8,364
Net Book Value	369			-123	246

Capital Asset Continuity Statements

* Asset retirements and other changes	2006	2007 Changes			2007
	Balance	Additions	Ret./Other *	Amortization	Balance
1940-Tools, Shop and Garage Equipment					
Gross Assets	185,874	33,125			218,999
Accumulated Amortization	-230,616			-3,863	-234,479
Net Book Value	-44,742	33,125		-3,863	-15,480
1945-Measurement and Testing Equipment					
Gross Assets	2,634				2,634
Accumulated Amortization					
Net Book Value	2,634				2,634
1955-Communication Equipment					
Gross Assets	131,713				131,713
Accumulated Amortization	-76,073			-3,791	-79,864
Net Book Value	55,640			-3,791	51,849
1960-Miscellaneous Equipment					
Gross Assets	19,220				19,220
Accumulated Amortization	-1,922			-592	-2,514
Net Book Value	17,298			-592	16,706
1980-System Supervisory Equipment					
Gross Assets	315,046	22,117			337,163
Accumulated Amortization	-183,694			-20,800	-204,494
Net Book Value	131,352	22,117		-20,800	132,669
1995-Contributions and Grants - Credit					
Gross Assets	-304,812	-218,797	-0		-523,610
Accumulated Amortization			-33,096	33,096	0
Net Book Value	-304,812	-218,797	-33,096	33,096	-523,609
TOTAL					
Gross Assets	**14,611,472**	**1,451,837**	**-67,943**		**15,995,366**
Accumulated Amortization	**-8,875,750**		**34,847**	**-523,913**	**-9,364,816**
Net Book Value	**5,735,722**	**1,451,837**	**-33,096**	**-523,913**	**6,630,550**

Capital Asset Continuity Statements

* Asset retirements and other changes	2007 Balance	2008 Changes Additions	Ret./Other *	Amortization	2008 Balance
1805-Land					
Gross Assets	365,298				365,298
Accumulated Amortization					
Net Book Value	365,298				365,298
1806-Land Rights					
Gross Assets	32,555				32,555
Accumulated Amortization	-15,060				-15,060
Net Book Value	17,495				17,495
1808-Buildings and Fixtures					
Gross Assets	916,499	23,200			939,699
Accumulated Amortization	-319,592			-29,541	-349,133
Net Book Value	596,907	23,200		-29,541	590,566
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	1,851,646	1,169,900			3,021,546
Accumulated Amortization	-861,198			-79,444	-940,641
Net Book Value	990,448	1,169,900		-79,444	2,080,904
1830-Poles, Towers and Fixtures					
Gross Assets	3,190,776	290,240			3,481,016
Accumulated Amortization	-1,629,194			-101,090	-1,730,283
Net Book Value	1,561,582	290,240		-101,090	1,750,732
1835-Overhead Conductors and Devices					
Gross Assets	1,588,472	153,960			1,742,432
Accumulated Amortization	-1,048,217			-50,326	-1,098,543
Net Book Value	540,255	153,960		-50,326	643,890
1840-Underground Conduit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1845-Underground Conductors and Devices					
Gross Assets	2,575,505	428,780			3,004,285
Accumulated Amortization	-1,714,334			-105,776	-1,820,110
Net Book Value	861,171	428,780		-105,776	1,184,175

Capital Asset Continuity Statements

* Asset retirements and other changes	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
1850-Line Transformers					
Gross Assets	2,447,823	481,840			2,929,663
Accumulated Amortization	-1,541,845			-90,745	-1,632,590
Net Book Value	905,977	481,840		-90,745	1,297,072
1855-Services					
Gross Assets	68,396	101,680			170,076
Accumulated Amortization	-3,703			-4,708	-8,411
Net Book Value	64,693	101,680		-4,708	161,666
1860-Meters					
Gross Assets	1,022,682	8,100			1,030,782
Accumulated Amortization	-558,550			-35,258	-593,808
Net Book Value	464,132	8,100		-35,258	436,974
1875-Street Lighting and Signal Systems					
Gross Assets	2,407				2,407
Accumulated Amortization	-2,407				-2,407
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	246,273				246,273
Accumulated Amortization	-208,945			-6,476	-215,421
Net Book Value	37,327			-6,476	30,851
1920-Computer Equipment - Hardware					
Gross Assets	388,674	13,213			401,887
Accumulated Amortization	-360,549			-11,337	-371,886
Net Book Value	28,125	13,213		-11,337	30,001
1925-Computer Software					
Gross Assets	279,858	14,000			293,858
Accumulated Amortization	-102,139			-49,766	-151,905
Net Book Value	177,720	14,000		-49,766	141,953
1930-Transportation Equipment					
Gross Assets	823,773	39,900			863,673
Accumulated Amortization	-469,368			-61,853	-531,220
Net Book Value	354,405	39,900		-61,853	332,452
1935-Stores Equipment					
Gross Assets	8,610				8,610
Accumulated Amortization	-8,364			-123	-8,487
Net Book Value	246			-123	123

Capital Asset Continuity Statements

* Asset retirements and other changes	2007	2008 Changes			2008
	Balance	Additions	Ret./Other *	Amortization	Balance
1940-Tools, Shop and Garage Equipment					
Gross Assets	218,999	33,200			252,199
Accumulated Amortization	-234,479			-7,179	-241,658
Net Book Value	-15,480	33,200		-7,179	10,541
1945-Measurement and Testing Equipment					
Gross Assets	2,634				2,634
Accumulated Amortization					
Net Book Value	2,634				2,634
1955-Communication Equipment					
Gross Assets	131,713				131,713
Accumulated Amortization	-79,864			-2,799	-82,663
Net Book Value	51,849			-2,799	49,050
1960-Miscellaneous Equipment					
Gross Assets	19,220				19,220
Accumulated Amortization	-2,514			-592	-3,106
Net Book Value	16,706			-592	16,114
1980-System Supervisory Equipment					
Gross Assets	337,163	28,640			365,803
Accumulated Amortization	-204,494			-22,492	-226,985
Net Book Value	132,669	28,640		-22,492	138,818
1995-Contributions and Grants - Credit					
Gross Assets	-523,610	-236,200			-759,810
Accumulated Amortization	0		-37,321	37,321	0
Net Book Value	-523,609	-236,200	-37,321	37,321	-759,809
TOTAL					
Gross Assets	**15,995,366**	**2,550,453**			**18,545,819**
Accumulated Amortization	**-9,364,816**		**-37,321**	**-622,181**	**-10,024,319**
Net Book Value	**6,630,550**	**2,550,453**	**-37,321**	**-622,181**	**8,521,501**

Capital Asset Continuity Statements

* Asset retirements and other changes	2008 Balance	2009 Changes Additions	2009 Changes Ret./Other *	2009 Changes Amortization	2009 Balance
1805-Land					
Gross Assets	365,298				365,298
Accumulated Amortization					
Net Book Value	365,298				365,298
1806-Land Rights					
Gross Assets	32,555				32,555
Accumulated Amortization	-15,060				-15,060
Net Book Value	17,495				17,495
1808-Buildings and Fixtures					
Gross Assets	939,699	35,000			974,699
Accumulated Amortization	-349,133			-30,996	-380,129
Net Book Value	590,566	35,000		-30,996	594,570
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	3,021,546	1,045,800			4,067,346
Accumulated Amortization	-940,641			-123,758	-1,064,399
Net Book Value	2,080,904	1,045,800		-123,758	3,002,947
1830-Poles, Towers and Fixtures					
Gross Assets	3,481,016	377,140			3,858,156
Accumulated Amortization	-1,730,283			-110,905	-1,841,189
Net Book Value	1,750,732	377,140		-110,905	2,016,967
1835-Overhead Conductors and Devices					
Gross Assets	1,742,432	165,260			1,907,692
Accumulated Amortization	-1,098,543			-55,212	-1,153,755
Net Book Value	643,890	165,260		-55,212	753,937
1840-Underground Conduit					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1845-Underground Conductors and Devices					
Gross Assets	3,004,285	377,780			3,382,065
Accumulated Amortization	-1,820,110			-121,907	-1,942,016
Net Book Value	1,184,175	377,780		-121,907	1,440,049

Capital Asset Continuity Statements

** Asset retirements and other changes*

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1850-Line Transformers					
Gross Assets	2,929,663	378,140			3,307,803
Accumulated Amortization	-1,632,590			-107,945	-1,740,535
Net Book Value	1,297,072	378,140		-107,945	1,567,267
1855-Services					
Gross Assets	170,076	98,880			268,956
Accumulated Amortization	-8,411			-8,719	-17,129
Net Book Value	161,666	98,880		-8,719	251,827
1860-Meters					
Gross Assets	1,030,782	10,000			1,040,782
Accumulated Amortization	-593,808			-35,620	-629,428
Net Book Value	436,974	10,000		-35,620	411,354
1875-Street Lighting and Signal Systems					
Gross Assets	2,407				2,407
Accumulated Amortization	-2,407				-2,407
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	246,273				246,273
Accumulated Amortization	-215,421			-6,425	-221,846
Net Book Value	30,851			-6,425	24,426
1920-Computer Equipment - Hardware					
Gross Assets	401,887	19,040			420,927
Accumulated Amortization	-371,886			-12,334	-384,220
Net Book Value	30,001	19,040		-12,334	36,707
1925-Computer Software					
Gross Assets	293,858	20,000			313,858
Accumulated Amortization	-151,905			-48,147	-200,052
Net Book Value	141,953	20,000		-48,147	113,806
1930-Transportation Equipment					
Gross Assets	863,673	335,000	-154,080		1,044,592
Accumulated Amortization	-531,220		154,080	-83,688	-460,827
Net Book Value	332,452	335,000		-83,688	583,765
1935-Stores Equipment					
Gross Assets	8,610				8,610
Accumulated Amortization	-8,487			-123	-8,610
Net Book Value	123			-123	0

Capital Asset Continuity Statements

* *Asset retirements and other changes*	2008	2009 Changes			2009
	Balance	Additions	Ret./Other *	Amortization	Balance
1940-Tools, Shop and Garage Equipment					
Gross Assets	252,199	10,000			262,199
Accumulated Amortization	-241,658			-9,339	-250,997
Net Book Value	10,541	10,000		-9,339	11,202
1945-Measurement and Testing Equipment					
Gross Assets	2,634				2,634
Accumulated Amortization					
Net Book Value	2,634				2,634
1955-Communication Equipment					
Gross Assets	131,713				131,713
Accumulated Amortization	-82,663			-1,992	-84,655
Net Book Value	49,050			-1,992	47,058
1960-Miscellaneous Equipment					
Gross Assets	19,220				19,220
Accumulated Amortization	-3,106			-592	-3,698
Net Book Value	16,114			-592	15,522
1980-System Supervisory Equipment					
Gross Assets	365,803	100,000			465,803
Accumulated Amortization	-226,985			-26,024	-253,009
Net Book Value	138,818	100,000		-26,024	212,794
1995-Contributions and Grants - Credit					
Gross Assets	-759,810	-225,200			-985,010
Accumulated Amortization	0		-48,300	48,300	0
Net Book Value	-759,809	-225,200	-48,300	48,300	-985,009
TOTAL					
Gross Assets	**18,545,819**	**2,746,840**	**-154,080**		**21,138,579**
Accumulated Amortization	**-10,024,319**		**105,780**	**-735,424**	**-10,653,963**
Net Book Value	**8,521,501**	**2,746,840**	**-48,300**	**-735,424**	**10,484,616**

Gross Assets Table

Included on the next page is the Gross Capital Assets Table which provides a listing of the Gross Capital Assets including, additions, retirements and other adjustments by APH USoA Number for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years.

Following the Gross Capital Assets Table is a further table showing the Net Capital Asset Balances. This table sets out the Gross Asset, Accumulated Amortization and Net Book Value by APH USoA Number for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years.

Both of these tables will be referred to in the Materiality/Variance Analysis on Gross Assets under Exhibit 2, Tab 2, Schedule 3 which directly follows the two tables.

Gross Capital Assets Table

Gross Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual: Additions	Variance to 2006 Actual: Retirements / Other	Variance to 2006 Actual: Ending Balance	2006 Actual Ending Balance	2007 Actual: Additions	2007 Actual: Retirements / Other	2007 Actual: Ending Balance
1610-Miscellaneous Intangible Plant								
1805-Land	365,298			365,298	365,298			365,298
1806-Land Rights	32,555			32,555	32,555			32,555
1808-Buildings and Fixtures	855,670	17,012	6,593	879,275	879,275	37,224	-0	916,499
1810-Leasehold Improvements								
1815-Transformer Station Equipment - Normally Primary above 50 kV								
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,040,689	60,010	36,679	1,137,378	1,137,378	714,268		1,851,646
1830-Poles, Towers and Fixtures	2,147,372	854,429	25,093	3,026,893	3,026,893	163,882		3,190,776
1835-Overhead Conductors and Devices	1,424,965	56,803	1,230	1,482,998	1,482,998	105,474		1,588,472
1840-Underground Conduit	1,436,491		-1,436,491					
1845-Underground Conductors and Devices	976,916	93,850	1,437,268	2,508,034	2,508,034	67,471		2,575,505
1850-Line Transformers	2,152,009	104,149	51,402	2,307,560	2,307,560	140,263		2,447,823
1855-Services	778	21,020	-0	21,798	21,798	46,599		68,396
1860-Meters	887,555	118,879	-2,569	1,003,864	1,003,864	18,818	0	1,022,682
1875-Street Lighting and Signal Systems	2,596		-188	2,407	2,407			2,407
1905-Land								
1906-Land Rights								
1908-Buildings and Fixtures								
1910-Leasehold Improvements								
1915-Office Furniture and Equipment	220,937	5,544	11,044	237,525	237,525	8,748		246,273
1920-Computer Equipment - Hardware	349,742	13,250	11,294	374,286	374,286	14,388		388,674
1925-Computer Software	63,109	45,403	25,076	133,588	133,588	146,271		279,858
1930-Transportation Equipment	712,216	260,034	-232,522	739,728	739,728	151,987	-67,942	823,773
1935-Stores Equipment	8,610			8,610	8,610			8,610
1940-Tools, Shop and Garage Equipment	171,059	8,859	5,956	185,874	185,874	33,125		218,999
1945-Measurement and Testing Equipment	2,634			2,634	2,634			2,634
1950-Power Operated Equipment								
1955-Communication Equipment	131,413		300	131,713	131,713			131,713
1960-Miscellaneous Equipment	18,335		885	19,220	19,220			19,220
1965-Water Heater Rental Units								
1970-Load Management Controls - Customer Premises								
1975-Load Management Controls - Utility Premises								
1980-System Supervisory Equipment	284,044	9,271	21,731	315,046	315,046	22,117		337,163
1985-Sentinel Lighting Rental Units								
1990-Other Tangible Property								
1995-Contributions and Grants - Credit	-212,621	-97,083	4,893	-304,812	-304,812	-218,797	-0	-523,610
2005-Property Under Capital Leases								
TOTAL	**13,072,370**	**1,571,429**	**-32,327**	**14,611,472**	**14,611,472**	**1,451,837**	**-67,943**	**15,995,366**

Gross Capital Assets Table

Gross Capital Asset Account	2007 Actual	2008 Projection			2008 Projection	2009 Projection		
	Ending Balance	Additions	Retirements / Other	Ending Balance	Ending Balance	Additions	Retirements / Other	Ending Balance
1610-Miscellaneous Intangible Plant								
1805-Land	365,298			365,298	365,298			365,298
1806-Land Rights	32,555			32,555	32,555			32,555
1808-Buildings and Fixtures	916,499	23,200		939,699	939,699	35,000		974,699
1810-Leasehold Improvements								
1815-Transformer Station Equipment - Normally Primary above 50 kV								
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,851,646	1,169,900		3,021,546	3,021,546	1,045,800		4,067,346
1830-Poles, Towers and Fixtures	3,190,776	290,240		3,481,016	3,481,016	377,140		3,858,156
1835-Overhead Conductors and Devices	1,588,472	153,960		1,742,432	1,742,432	165,260		1,907,692
1840-Underground Conduit								
1845-Underground Conductors and Devices	2,575,505	428,780		3,004,285	3,004,285	377,780		3,382,065
1850-Line Transformers	2,447,823	481,840		2,929,663	2,929,663	378,140		3,307,803
1855-Services	68,396	101,680		170,076	170,076	98,880		268,956
1860-Meters	1,022,682	8,100		1,030,782	1,030,782	10,000		1,040,782
1875-Street Lighting and Signal Systems	2,407			2,407	2,407			2,407
1905-Land								
1906-Land Rights								
1908-Buildings and Fixtures								
1910-Leasehold Improvements								
1915-Office Furniture and Equipment	246,273			246,273	246,273			246,273
1920-Computer Equipment - Hardware	388,674	13,213		401,887	401,887	19,040		420,927
1925-Computer Software	279,858	14,000		293,858	293,858	20,000		313,858
1930-Transportation Equipment	823,773	39,900		863,673	863,673	335,000	-154,080	1,044,592
1935-Stores Equipment	8,610			8,610	8,610			8,610
1940-Tools, Shop and Garage Equipment	218,999	33,200		252,199	252,199	10,000		262,199
1945-Measurement and Testing Equipment	2,634			2,634	2,634			2,634
1950-Power Operated Equipment								
1955-Communication Equipment	131,713			131,713	131,713			131,713
1960-Miscellaneous Equipment	19,220			19,220	19,220			19,220
1965-Water Heater Rental Units								
1970-Load Management Controls - Customer Premises								
1975-Load Management Controls - Utility Premises								
1980-System Supervisory Equipment	337,163	28,640		365,803	365,803	100,000		465,803
1985-Sentinel Lighting Rental Units								
1990-Other Tangible Property								
1995-Contributions and Grants - Credit	-523,610	-236,200		-759,810	-759,810	-225,200		-985,010
2005-Property Under Capital Leases								
TOTAL	**15,995,366**	**2,550,453**		**18,545,819**	**18,545,819**	**2,746,840**	**-154,080**	**21,138,579**

Net Capital Asset Table

Account Description	2006 EDR Approved - Ending Balances			2006 Actual - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1610-Miscellaneous Intangible Plant						
1805-Land	365,298		365,298	365,298		365,298
1806-Land Rights	32,555	-15,060	17,495	32,555	-15,060	17,495
1808-Buildings and Fixtures	855,670	-236,926	618,744	879,275	-291,562	587,714
1810-Leasehold Improvements						
1815-Transformer Station Equipment - Normally Primary above 50 kV						
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,040,689	-757,771	282,918	1,137,378	-819,437	317,941
1830-Poles, Towers and Fixtures	2,147,372	-1,295,265	852,107	3,026,893	-1,534,250	1,492,643
1835-Overhead Conductors and Devices	1,424,965	-851,330	573,635	1,482,998	-1,001,700	481,298
1840-Underground Conduit	1,436,491		1,436,491			
1845-Underground Conductors and Devices	976,916	-1,369,793	-392,877	2,508,034	-1,616,188	891,847
1850-Line Transformers	2,152,009	-1,281,147	870,862	2,307,560	-1,463,543	844,017
1855-Services	778		778	21,798	-1,961	19,837
1860-Meters	887,555	-497,579	389,976	1,003,864	-523,831	480,034
1875-Street Lighting and Signal Systems	2,596		2,596	2,407	-2,596	-189
1905-Land						
1906-Land Rights						
1908-Buildings and Fixtures						
1910-Leasehold Improvements						
1915-Office Furniture and Equipment	220,937	-184,705	36,232	237,525	-202,825	34,700
1920-Computer Equipment - Hardware	349,742	-282,922	66,820	374,286	-348,674	25,612
1925-Computer Software	63,109	-19,229	43,880	133,588	-65,196	68,392
1930-Transportation Equipment	712,216	-684,348	27,868	739,728	-488,381	251,347
1935-Stores Equipment	8,610	-7,796	814	8,610	-8,241	369
1940-Tools, Shop and Garage Equipment	171,059	-165,611	5,448	185,874	-230,616	-44,742
1945-Measurement and Testing Equipment	2,634	-2,439	195	2,634		2,634
1950-Power Operated Equipment						
1955-Communication Equipment	131,413	-108,477	22,936	131,713	-76,073	55,640
1960-Miscellaneous Equipment	18,335	-18,049	286	19,220	-1,922	17,298
1965-Water Heater Rental Units						
1970-Load Management Controls - Customer Premises						
1975-Load Management Controls - Utility Premises						
1980-System Supervisory Equipment	284,044	-125,598	158,446	315,046	-183,694	131,352
1985-Sentinel Lighting Rental Units						
1990-Other Tangible Property						
1995-Contributions and Grants - Credit	-212,621		-212,621	-304,812		-304,812
2005-Property Under Capital Leases						
TOTAL	**13,072,370**	**-7,904,045**	**5,168,325**	**14,611,472**	**-8,875,750**	**5,735,722**

Net Capital Asset Table

Amounts from sheets B1 and B2

Account Description	2007 Actual - Ending Balances			2008 Projection - Ending Balances			2009 Projection - Ending Balances		
	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value	Gross Assets	Accumulated Amortization	Net Book Value
1610-Miscellaneous Intangible Plant									
1805-Land	365,298		365,298	365,298		365,298	365,298		365,298
1806-Land Rights	32,555	-15,060	17,495	32,555	-15,060	17,495	32,555	-15,060	17,495
1808-Buildings and Fixtures	916,499	-319,592	596,907	939,699	-349,133	590,566	974,699	-380,129	594,570
1810-Leasehold Improvements									
1815-Transformer Station Equipment - Normally Primary above 50 kV									
1820-Distribution Station Equipment - Normally Primary below 50 kV	1,851,646	-861,198	990,448	3,021,546	-940,641	2,080,904	4,067,346	-1,064,399	3,002,947
1830-Poles, Towers and Fixtures	3,190,776	-1,629,194	1,561,582	3,481,016	-1,730,283	1,750,732	3,858,156	-1,841,189	2,016,967
1835-Overhead Conductors and Devices	1,588,472	-1,048,217	540,255	1,742,432	-1,098,543	643,890	1,907,692	-1,153,755	753,937
1840-Underground Conduit									
1845-Underground Conductors and Devices	2,575,505	-1,714,334	861,171	3,004,285	-1,820,110	1,184,175	3,382,065	-1,942,016	1,440,049
1850-Line Transformers	2,447,823	-1,541,845	905,977	2,929,663	-1,632,590	1,297,072	3,307,803	-1,740,535	1,567,267
1855-Services	68,396	-3,703	64,693	170,076	-8,411	161,666	268,956	-17,129	251,827
1860-Meters	1,022,682	-558,550	464,132	1,030,782	-593,808	436,974	1,040,782	-629,428	411,354
1875-Street Lighting and Signal Systems	2,407	-2,407		2,407	-2,407		2,407	-2,407	
1905-Land									
1906-Land Rights									
1908-Buildings and Fixtures									
1910-Leasehold Improvements									
1915-Office Furniture and Equipment	246,273	-208,945	37,327	246,273	-215,421	30,851	246,273	-221,846	24,426
1920-Computer Equipment - Hardware	388,674	-360,549	28,125	401,887	-371,886	30,001	420,927	-384,220	36,707
1925-Computer Software	279,858	-102,139	177,720	293,858	-151,905	141,953	313,858	-200,052	113,806
1930-Transportation Equipment	823,773	-469,368	354,405	863,673	-531,220	332,452	1,044,592	-460,827	583,765
1935-Stores Equipment	8,610	-8,364	246	8,610	-8,487	123	8,610	-8,610	0
1940-Tools, Shop and Garage Equipment	218,999	-234,479	-15,480	252,199	-241,658	10,541	262,199	-250,997	11,202
1945-Measurement and Testing Equipment	2,634		2,634	2,634		2,634	2,634		2,634
1950-Power Operated Equipment									
1955-Communication Equipment	131,713	-79,864	51,849	131,713	-82,663	49,050	131,713	-84,655	47,058
1960-Miscellaneous Equipment	19,220	-2,514	16,706	19,220	-3,106	16,114	19,220	-3,698	15,522
1965-Water Heater Rental Units									
1970-Load Management Controls - Customer Premises									
1975-Load Management Controls - Utility Premises									
1980-System Supervisory Equipment	337,163	-204,494	132,669	365,803	-226,985	138,818	465,803	-253,009	212,794
1985-Sentinel Lighting Rental Units									
1990-Other Tangible Property									
1995-Contributions and Grants - Credit	-523,610	0	-523,609	-759,810	0	-759,809	-985,010	0	-985,009
2005-Property Under Capital Leases									
TOTAL	**15,995,366**	**-9,364,816**	**6,630,550**	**18,545,819**	**-10,024,319**	**8,521,501**	**21,138,579**	**-10,653,963**	**10,484,616**

Materiality/Variance Analysis on Gross Assets

The calculation of the materiality level as set out in the Filing Guidelines is 1% of net fixed assets. The calculation of the Materiality Threshold on net assets is shown in the following table:

Table 19 Materiality Threshold

	EDR – 2006	Actual - 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross Cost	$13,072,370	$14,611,472	$15,995,366	$18,545,819	$21,138,579
Accumulated Amortization	$ 7,904,045	$ 8,875,750	$ 9,364,816	$10,024,319	$10,653,963
Net Fixed Assets	$ 5,168,325	$ 5,735,722	$ 6,630,550	$ 8,521,501	$10,484,616
Percent	1%	1%	1%	1%	1%
Threshold	$51,683	$57,357	$66,305	$85,215	$104,846

MPUC as selected the lowest materiality threshold of $51,683 to allow for the most detailed review of gross asset changes. Those variances on a USoA Number basis that have exceeded this materiality level and those variances that are under the 1% are explained on the pages following.

Contributed Capital: Customers request MPUC to complete work at their premises. MPUC assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in USoA Number 1995 – Contributed Capital. MPUC increases the asset account number and records the corresponding credit to Contributed Capital Account #1995. Contributed Capital asset additions are identified by “CC” after the description of the addition on both Exhibit 2, Tab 2, Schedule 3 and Exhibit 2, Tab 3, Schedule 1.

Historical Board Approved to Actual 2006

The Actual ending balance for Capital Assets as at December 31, 2006 is $14,611,472 vs. the EDR ending balance of $13,072,370. The variance, $1,539,101 is a combination of additions/retirements in 2006 and in 2005, and in part is due to the balance shown as 2006 EDR which is an averaging of the 2003 and 2004 Capital Asset balances.

Explanations of variances greater than 1% are set out as follows:

Acct # & Name	Year	Amount	Description of Addition
#1820 - Distribution Plant	2005	$7,225	Supply and installation of materials to upgrade the dip pole structures at the Montreal Street substation
		$ 609	Supply and installation of materials to upgrade the dip pole structures at the Queen Street substation
		$11,214	To supply and install 4/0 XLPE (cross link polyethylene cable) from the dip to the breakers on Feeder 4 at the Fourth Street substation
		$4,860	To sand blast, remove the rust and paint the switch gear at the Brandon substation to prevent water leaking onto the breakers and relays
	TOTAL 2005	**$23,908**	
	2006	$26,154	Cost of study to establish long term direction for MPUC's infrastructure. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2006-01 – Substation Infrastructure Study.
		$8,617	Supply and installation of stone/gravel at the Dorion and Brandon Substations as per recommendations from ESA's due diligence inspection report
		$1,331	Scott Street Substation labour for substation work
	TOTAL 2006	$36,102	
	TOTAL 2005 and 2006	$60,010	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$36,679	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance. – as per Retirements/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1830 – Poles, Towers & Fixtures	2005	$18,960	OLD PENETANG ROAD -This project provided a feeder tie line between Yonge Street and Hugel Avenue. An overhead, 3-phase 4.16/2.4 kv poleline was constructed. As the electric demands along Yonge Street increase due to recent developments, a backup source is required to better manage the feeder balancing and load distribution between feeder 1 and feeder 5 from the Montreal Street substation.

		$21,635	Johnson Street Rebuild – repoling on John Street from Hanly to Colborne Streets.
		$2,137	Yonge & Queen Pole Replacement: Existing pole had to be replaced due to rotting of the upper part of the pole. This job included the replacement of hardware on the 4.16 distribution system and the 44 Kv circuit and transfer of conductors to new pole.
		$13,009	Dorion Street Feeder: As the demand on the east side of William Street increases as a result of recent and future development, an extra feeder was constructed along Dorion Road to accommodate the extra load. The pole line will remain but the poles must be re-hardwared and new conductors installed from the substation to William Street.
		$324,239	44KV FEEDER : The 44 kv pole line along the south side of Highway 12 from Kindred to Huronia Precision Plastics was in need of replacement. It carries the 98-M2 feeder, which is one of the two main feeders in Town, and has two 4.16/2.4 kv distribution circuits. This poleline has been installed for many years and needs to be upgraded. The poles and wood crossarms are in bad condition. The demand has increased with the construction of Wal-Mart and the future commercial development. Increased loads on this feeder will also occur as Kindred, Georgian College (IRDI), Huronia Precision Plastics and St. Theresa's High School upgrade their services. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2005-01 – 44 KV Distribution System.
		$3,500	Pillsbury Pole Replacement – Change out burned pole north of Pillsbury
		$5,065	William Street Pole Replacement: Existing pole had to be replaced due to rotting of the upper part of the pole. This job included the replacement of hardware on the 4.16 distribution systems and the 44 Kv circuit and transfer of conductors to new pole.
		$2,272	Scully's Pole Installation: The capital work performed at Scully's was an addition to the Bayshore Pole Line Upgrade. It entailed the installation of a new pole to accommodate a three-phase bank of transformers for services to Scully's and the town dock.
		$1,486	Miscellaneous Jobs – Hillcrest Lane pole change and feeder work ($917.31); poles at Brandon ($568.72);
	TOTAL 2005	$392,302	
	2006	$18,288	44 KV rebuild that included pole line reconstruction on Gloucester St. Between Russell St. And Charles St. As a preventative measure to reduce the high probability of power outages caused by the aging effect of the wood poles and wood crossarms, and as a measure to prevent hazardous situations from occurring for both line crew and the public. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2006-02 – 44kv Rebuild.

		$32,772	44 KV rebuild that included pole line reconstruction on William St. Between Gloucester St. And Bay St. As a preventative measure to reduce the high probability of power outages caused by the aging effect of the wood poles and wood crossarms, and as a measure to prevent hazardous situations from occurring for both line crew and the public. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2006-02 – 44kv Rebuild.
		$321,522	The reconstruction of the 44 KV Rebuild by mcnamara Powerlines included the reconstruction of the 44 KV pole line that runs along the Rotary Trail from Manly Street to Victoria Street, the reconstruction of the section of line that runs from the run off at ADM Milling, through the Timber Mart lumber yard then to Fourth Street, and the installation of two air break switches. One to be installed at Manly St. And Bayshore Dr., and the other at Highway 12 and Kindred Road. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description: #2006-02 – 44kv Rebuild.
		$3,702	Pole line rebuild from the Scott St. Substation to Johnson St. This is necessary in order to add a new feeder to compliment the extra circuit provided by the new breaker in Scott St. Substation.
		$1,112	Scott Street Substation pole construction
		$421	Griffin Street pole construction
		$8,935	Gervais Street pole construction
		$529	County Road 93 pole construction
		$213	Pillsbury & Trilet pole construction
		$2,082	New pole construction – bay street
		$5,512	Bay Street pole construction
		$4,894	Smith's Camp, Yonge St, George Stl, Little Lake pole construction
		$1,046	Upgrade/replacement of existing non-conforming meter installations required by the IESO. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description: #2006-03 – Wholesale Metering Points.
		$3,497	Pole construction at Latter Day Saints Church on Golf Link Road – CC
		$2,805	Pole construction – Wilson High Voltage – dead end pole at end of the road - CC
		$4,210	Smith's Trailer Camp – Replace poles- CC
		$1,110	Sarjeant's – County Road #93 – pole replacement- CC
		$7,325	Little Lake Park – installation of poles- CC
		$957	Little Lake Park – replacement of pole- CC
		$563	New pole – easy street- cc
		$6,347	Mundy's Bay Condo Development – construction of poles- CC
		$16,658	St. Theresa's High School – pole construction- CC
		$6,470	Vinden Street Flume – pole construction- CC
		$2,026	Curling Club – pole construction- CC
		$5,711	Well #7 – Highway #12 – 3 phase transformer bank- CC

		$2,543	Spahr – pole construction- CC
		$874	Badger – pole contract
	TOTAL 2006	$462,126	
	TOTAL 2005 and 2006	$854,429	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$25,093	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance. – as per Retirements/Other Column on Gross Capital Assets Table.

Acct # & Name	Year	Amount	Description of Addition
#1835 –Overhead Conductors & Devices	2005	$1,815	Johnson Street Rebuild – reconductoring of the pole line on John Street from Hanly to Colborne Streets.
		$3,069	Yonge & Queen Pole Replacement: This job included the replacement of hardware on the 4.16 distribution systems and the 44 Kv circuit and transfer of conductors to new pole.
		$3,756	Dorion Street Feeder : As the demand on the east side of William Street increases as a result of recent and future development, an extra feeder was constructed along Dorion Road to accommodate the extra load. The pole line will remain but the poles must be re-hardwared and new conductors installed from the substation to William Street.
		$3,701	44KV FEEDER : The 44 kv pole line along the south side of Highway 12 from Kindred to Huronia Precision Plastics was in need of replacement. It carries the 98-M2 feeder, which is one of the two main feeders in Town, and has two 4.16/2.4 kv distribution circuits. This poleline has been installed for many years and needs to be upgraded. Also, the existing conductor, which is a 1/0 ACSR (aluminum conductor steel reinforced), must be upgraded to 336mcm to accommodate the future loads. The demand has increased with the construction of Wal-Mart and the future commercial development. Increased loads on this feeder will also occur as Kindred, Georgian College (IRDI), Huronia Precision Plastics and St. Theresa's High School upgrade their services. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2005-01 – 44 KV Distribution System.
		$803	Pole replacement at William Street required the transfer of the conductor from the old poles to the new poles
		$5,086	Colborne & Dorion poleline conductor installation
		$340	Hillcrest Lane Pole Change & Feeder work
	TOTAL 2005	$18,571	
	2006	$25,377	Cost of study to establish long term direction for MPUC's infrastructure. This study provided an analysis of existing infrastructure and a plan for replacement of substations taking into consideration future growth in our distribution territory. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description

			#2006-01 – Substation Infrastructure Study.
		$5,954	Pillsbury & Trilet conductor installation
		$525	New Pole construction and conductor transfer– Bay Street
		$1,780	Cranston Crescent – conductor transfer
		$550	George Street – conductor transfer
		$4,046	Georgian College – Prospect Blvd – overhead construction, including conductors - CC
	TOTAL 2006	$38,232	
	TOTAL 2005 and 2006	$56,803	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$1,230	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance. – as per Retirements/Other Column on Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1840 – Underground Conduit	2005	$0	No underground conduit at MPUC – see 2006 comments below
	TOTAL 2005	$1,436,491	
	2006	$-1,436,491	Due to inadvertence, the amount shown in Account #1840 Underground Conduit should be shown in Underground Conductors and Devices. As at December 31, 2006 MPUC does not have Underground Conduit and the reallocation was made from Account #1840 Underground Conduit to account number #1845 Underground Conductors and Devices in 2006.
	TOTAL 2006	$-1,436,491	
	TOTAL 2005 and 2006	$-1,436,491	Total Retirements/Other per Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1845 – Underground Conductors & Devices	2005	$51,322	A program to replace the existing kabars which are primary switching junctions. Many kabars have been installed for more than 25 years and are now deteriorating. As the nature of the work to change a unit may vary due to unforeseen circumstances such as defective elbows, the cost to replace one kabar will vary proportionately. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2005-02 – Kabar Replacements.
	TOTAL 2005	$51,322	
	2006	$2,890	Fault current indicators along the 44 KV system are installed along the sections of line in an off road area and will facilitate the location of line faults.
		$5,044	Replacement of rusted Kabars
		$2,506	Infrared Study
		$3,379	Mapledawn Subdivision installation of Kabars - CC
		$674	Mundy's Bay Condo Development installation of Kabars- CC
		$764	Mundy's Bay Condo Development installation of Kabars- CC
		$1,310	Mundy's Bay Condo Development installation of Kabars- CC
		$750	Aberdeen – energize new underground plant- CC
		$500	Aberdeen – install cable in live s/w centre- CC

		$6,307	Tiffin Place – underground installation- CC
		$1,133	Pumphouse – primary cables- CC
		$1,115	New conductor for streetlights- CC
		$12,575	Timberridge Development – William Street installation- CC
		$958	Timberridge Development – William Street installation- CC
		$388	Installation of wire – Sparkling- CC
		$2,236	Materials and labour for new service at Weld-Tek on William Street- CC
	TOTAL 2006	$42,528	
	TOTAL 2005 and 2006	$93,850	Total Additions per Gross Capital Assets Table
	Reallocation in 2006 from Acct #1840	$1,436,491	Due to inadvertence, the amount shown in Account #1840 Underground Conduit should be shown in Underground Conductors and Devices. As at December 31, 2006 MPUC does not have Underground Conduit and the reallocation was made from Account #1840 Underground Conduit to account number #1845 Underground Conductors and Devices in 2006.
	TOTAL 2003 & 2004 averaging	$778	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance.
	Total 2003/2004 Averaging and Reallocation	$1,437,268	Total Retirements/Other per Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1850 – Line Transformers	2005	$449	44KV FEEDER : The 44 kv pole line along the south side of Highway 12 from Kindred to Huronia Precision Plastics was in need of replacement. It carries the 98-M2 feeder, which is one of the two main feeders in Town, and has two 4.16/2.4 kv distribution circuits. Labour costs will be incurred to transfer the transformers from the old poleline to the new poleline. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description #2005-01 – 44 KV Distribution System.
		$13,151	Transformer replacement and maintenance program. Initially the program will begin with the replacement of approximately seven new transformers. When these transformers are returned to stock, they will be shipped to Grafton who will perform a physical and electric inspection of the transformers. From Grafton's report, some of the transformers may be listed as scrap, while others may be repairable. Those that are repairable will be repaired and will be used to replace other rusted out transformers.
		$1,025	Bourgeois Lane transformer
		$7,326	Purchase of transformers
		$8,415	Purchase of minipad transformers
	TOTAL 2005	$30,367	
	2006	$28,100	Distribution Transformer purchases throughout the year in keeping with plan for replacement as set out in 2005
		$12,713	Transformer installations at Aberdeen – Tiffin Place- CC

		$911	Vindin Street – Flume Water Pumphouse – transformer- CC
		$5,731	Vindin Street – Flume Water Pumphouse – transformer- CC
		$1,428	Well #7 Hwy 12 – install 3 phase transformer bank- CC
		$15,041	Midland Car Wash on King Street – transformer installation- CC
		$740	8933 County Rd 93 – transformer installation- CC
		$9,119	William Street transformer installation- CC
	TOTAL 2006	$73,782	
	TOTAL 2005 and 2006	$104,149	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$51,402	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance. – as per Retirements/Other Column on Gross Capital Assets Table.

Acct # & Name	Year	Amount	Description of Addition
#1860 – Meters	2005	$7,950	Purchase of meters throughout the year
	TOTAL 2005	$7,950	
	2006	$25,233	Purchase of Smart Meters approved under CDM Third Tranche
		$19,675	Meter purchases for new installations
		$66,020	Upgrade/replacement of existing non-conforming meter installations required by the IESO. Wholesale Metering Point meters to be replaced in 2006 are the primary meters on the 98-M2 and the 98-M4. Due to the strike at Hydro One in 2005, These will be the last of the wholesale meters in Midland to be replaced. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description: #2006-03 – Wholesale Metering Points.
	TOTAL 2006	$110,929	
	TOTAL 2005 & 2006	$118,879	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$-2,569	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance as adjusted for Tier 1 Expenses and the 2006 EDR Balance. – as per Retirements/Other Column on Gross Capital Assets.

Acct # & Name	Year	Amount	Description of Addition
#1925 – Computer Software	2005	$3,762	Purchase of Collections Module for billing software from Advanced Utility Systems
	TOTAL 2005	$3,762	
	2006	$15,616	SQL conversion – converting from Oracle database
		$26,025	Billing Software conversion – Advanced Software to Harris Software – Advanced Software is no longer supported after December, 2008
	TOTAL 2006	$41,641	
	TOTAL 2005 and 2006	$45,403	Total Additions per Gross Capital Assets Table
	TOTAL 2003 & 2004 averaging	$25,076	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance. – as per Retirements/Other Column on

			the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1930 – Rolling Stock	2006 Additions	$212,863	Purchase of new Truck #1 - Digger/Derrick – 2007 International Truck. This cost forms part of one of MPUC's major projects for the year. A full description of the project is provided in the Capital Plan by Project at Exhibit 2, Tab 3, Schedule 1, as Project Description: #2006-04 – Purchase of Digger/Derrick Truck.
		$29,303	Truck #9 – new purchase – 2006 GMC Sierra Pickup
		$11,556	Purchase of Forklift
		$6,313	Purchase of utility trailer
	Total 2006 Additions	$260,034	Total Additions per Gross Capital Assets Table
	2005 Retirements	-$16,625	Removal of Truck #7 – 1995 GMC Sonoma Pickup from fleet – fully amortized
		-$17,778	Removal of Truck #12 – 1996 Chev S-10 Pickup from fleet – fully amortized
	TOTAL 2005	-$34,403	
	2006 Retirements	-$152,081	Removal of Truck #1 – 1991 Ford F800 – Digger Derrick – fully amortized
		-$13,043	Removal of Truck #8 - pick up truck – fully amortized
		-$15,888	Removal of Truck #9 – 1995 GMC Sonoma Pickup - fully amortized
		-$20,518	Removal of Truck #10 – 1987 Ford truck – fully amortized
		-$13,905	Removal of Truck #11 – pick up truck - fully amortized
	Total 2006 Retirements	-$215,435	
	Total 2005 & 2006 Retirements	$-249,838	Total Retirements in 2005 and 2006
	TOTAL 2003 & 2004 averaging	$17,316	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance.
	Total Retirements and 2003/2004 Averaging	$-232,522	Total per Gross Capital Assets Table under Column Retirements/Other .

Acct # & Name	Year	Amount	Description of Addition
#1995 – Contributions and Grants	2005/2006	$70,781	Amortization
	2005/2006 Additions	-$4,046	Georgian college – prospect blvd
		-$11,955	New services
		-$3,379	Mapledawn Subdivision installation of Kabars
		-$674	Mundy's bay condo development kabars
		-$764	Mundy's bay condo development kabars

		-$1,310	Mundy's bay condo development kabars
		-$6,347	Mundy's bay condo development pole line
		-$1,250	Aberdeen – energize new plant & install cable
		-$16,658	St. Theresa's School – pole construction
		-$19,019	Tiffin Place – underground construction
		-$911	Vindin street transformer
		-$12,201	Vindin street transformer
		-$2,026	Curling Club – pole construction
		-$7,139	Well #7 Hwy 12 – install 3 phase transformer bank
		-$1,133	Pumphouse – primary cables
		-$2,543	Spahr – pole construction
		-$18,578	Midland Car Wash – transformer and new service
		-$1,115	Streetlights –new conductor
		-$5,829	Pole construction – latter day st. Church
		-$13,532	Timberridge development – william street u/g
		-$1,322	Sparkling Cherry – new service & wire inst'n
		-$1,963	New services
		-$2,805	Pole construction – Wilson
		-$4,210	Smith's Trailer Park – replace poles
		-$1,850	County Rd #93 – Sarjeant's – pole replacement
		-$8,282	Little Lake Park – pole installation
		-$11,355	New service – weld tek – william street
		-$5,667	Refund to developer - mapledawn
	Total 2005/2006 Additions	-$167,864	
		-$97,083	Net Additions for 2005/2006 per Gross Capital Assets Table
	Total 2003/2004	$4,893	The balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is set out on the Gross Capital Assets Table under the Retirements/Other Column.

1

Reconciliation to Gross Capital Assets Table

Capital Additions, Retirements/Other are itemized in the Gross Capital Assets Table . Account variances greater than 1% have been explained above. Those additions with a variance of less than 1%.represent miscellaneous additions to the USofA accounts as follows:

Acct # & Name	Year	Amount	Description of Addition
#1808 - Buildings & Fixtures	2005/2006	$17,012	Additions throughout 2005 and 2006 include upgrades to the Quanset Hut , paving and purchase of a generator. This amount is shown on the Additions Column on the Gross Capital Assets Table
		$6,593	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1855 - Services	2005/2006	$21,020	the balance shown as 2006 EDR ($778) plus additions in 2005 and 2006 of $21020 total $21,798 of which $20,157 were contributed capital (CC) projects. The additions represent services added throughout 2005 and 2006 as shown on the Additions Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1875 - Streetlighting	2005/2006	$-188	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1915 – Office Furniture Equipment	2005/2006	$5,544	Total Additions include the purchase of filing cabinets, a desk, shelving, phones and projector. This amount is shown on the Additions Column on the Gross Capital Assets Table
		$11,044	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1920 – Computer Hardware	2005/2006	$13,250	Total Additions include the purchase of a Blackberry, external hard drive, modular switch chassis, monitors, printer, computer, UPS. This total is shown on the Additions Column on the Gross Capital Assets Table
		$11,294	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1940 – Tools, Shop & Garage Equipment	2005/2006	$8,859	Total Additions include the purchase of an 8 foot hose, Cable Height Meter, Tree Pruners c/w Hoses, Potential Indicator, Insulation and Semicon Stripper, Ratchet Elbow Puller, Set of Custom Grounds. This total is shown on the Additions Column on the Gross Capital Assets Table
		$5,956	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table.

Acct # & Name	Year	Amount	Description of Addition
#1955 – Communication Equipment	2005/2006	$300	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1960 – Miscellaneous Equipment	2005/2006	$885	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1980 – System Supervisory Equipment	2005/2006	$9,271	Additions include two-way radio communications; RTUs. This total is shown on the Additions Column on the Gross Capital Assets Table
		$21,731	the balance shown as 2006 EDR represents an averaging of the 2003 and 2004 Capital Asset balances. This amount is the difference between the actual December 31, 2004 balance and the 2006 EDR Balance and is shown under the Retirement/Other Column on the Gross Capital Assets Table

2006 Actual to 2007 Actual

Actual ending balance for Capital Assets as at December 31, 2006 is $14,611,472 vs. Actual Capital Assets at December 31, 2007 of $15,995,366. The variance, $1,383,894 is as a result of additions of $1,451,837 and retirements of $67,943 throughout the 2007 year.

1 Explanations of variances greater than the materiality level of $51,683 are as follows:

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Acct # & name	Year	Amount	Description of addition
#1820 – distribution plant	2007	$8,722	Queen street substation labour and materials. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-02 – queen street rebuild – gloucester street to yonge st.
		$679,052	Scott street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The scott street upgrade included transformer replacement including disposal of the 3000 kva transformer, the installation of the 5000 kva transformer. Secondary switchgear replacement includes the supply and installation of four 5 kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker and four 1200 amp feeder breakers, and the supply and installation of four underground feeders. Relay protection upgrades include the replacement of existing relays with four schweitzer protection and breaker control relays. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-04 – scott street substation.
		$24,394	Dorion substation – ground grid design and study and installation of ground grid
		$2,100	Brandon substation –removal of old brandon substation
	Total 2007	$714,268	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1830 – poles, towers & fixtures	2007	$1,008	Queen street poleline rebuilding – gloucester to hugel - 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. New 3 phase conductor wire will be placed. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. . This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-02 – queen street rebuild – gloucester street to yonge st.
		$2,579	Scott street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The scott street upgrade included transformer replacement including disposal of the 3000 kva transformer, the installation of the 5000 kva transformer. Secondary switchgear replacement includes the supply and installation of four 5 kv-3000 amp breaker

			cells, supply and installation of one 2000 amp main breaker and four 1200 amp feeder breakers, and the supply and installation of four underground feeders. Relay protection upgrades include the replacement of existing relays with four schweitzer protection and breaker control relays. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-04 – scott street substation.
		$41,878	Queen street poleline rebuild – hugel to yonge. 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. New 3 phase conductor wire will be placed. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. . This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-02 – queen street rebuild – gloucester street to yonge st.
		$4,058	Replacement of selected poles throughout the town of midland. All identified poles selected are in poor condition. Pole tops are rotting from years of adverse weathering effects with some being damaged due to snow plowing operations and other vehicle mishaps. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed as required.
		$57,878	Replacement of poles and one aging air brake switch located off william street (tiffin park) in the town of midland. The existing switch is in poor condition from years of adverse weathering effects with some rusting and oxidation. Replacing the 44kv air brake switch will help preventing power outages to midland's large users and six substations. Also, reconfiguring the present abs location will eliminate 2 poles. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-03 – tiffin park 44kv pole & abs replacement.
		$2,847	Project is to provide a loop feed back-up to an existing pad-mount transformer on bourgeois lane at the rear of the bell canada building. The scope of this project involves pole configuration and placing primary conductor between to pad mount transformers located beside one another. At the completion of this project, the existing radial feed will be replaced with a loop feed, thereby improving reliability of power to our customers. In addition, the operations department will have the ability to balance existing circuit loads.
		$421	New connection golf links road
		$2,751	William street pole line
		$3,940	New pole construction for red carpet inn

		$3,968	New pole construction – miscellaneous jobs
		$7,377	Installation of poles at prospect blvd - cc
		$1,308	Installation of poles at 576 easy street- cc
		$5,278	Installation of poles at penetanguishene & hugel ave- cc
		$28,591	Installation of poles at little lake- cc
	Total 2007	$163,882	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1835 – overhead conductors and devices	2007	$19,232	Queen street poleline rebuild. Gloucester to hugel new 3 phase conductor wire will be placed. The existing conductor wire is undersized for present load demands. Upgrading to a larger gauge conductor (336.4 ascr) wire improve line loss efficiency. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-02 – queen street rebuild – gloucester street to yonge st.
		$7,935	Scott street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The scott street upgrade included transformer replacement including disposal of the 3000 kva transformer, the installation of the 5000 kva transformer. Secondary switchgear replacement includes the supply and installation of four 5 kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker and four 1200 amp feeder breakers, and the supply and installation of four underground feeders. Relay protection upgrades include the replacement of existing relays with four schweitzer protection and breaker control relays. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-04 – scott street substation.
		$6,534	Queen street poleline rebuild hugel to yonge st. New 3 phase conductor wire will be placed. The existing conductor wire is undersized for present load demands. Upgrading to a larger gauge conductor (336.4 ascr) wire improve line loss efficiency. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-02 – queen street rebuild – gloucester street to yonge st.
		$5,561	Installation of 44kv lightening arresters on the 44 kv circuits that are remotely monitored by the existing wireless scada system. The installation of 44kv polymer arresters will protect the scada system from electrical surges caused by accidental circuit shorts (i.e. Lightening strikes, trees falling

			on wires and so on...).
		$306	Project is to provide a loop feed back-up to an existing pad-mount transformer on bourgeois lane at the rear of the bell canada building. The scope of this project involves pole configuration and placing primary conductor between to pad mount transformers located beside one another. At the completion of this project, the existing radial feed will be replaced with a loop feed, thereby improving reliability of power to our customers. In addition, the operations department will have the ability to balance existing circuit loads.
		$2,621	New connection golf links road
		$336	New pole construction and conductor work for red carpet inn
		$21,329	New pole construction, including conductor work– huron park, super 8 & bay port marina
		$17,304	Conductors work - pillsbury drive- cc
		$5,278	Installation of conductors at penetanguishene & hugel ave-cc
		$17,531	General mills – 44kv relocate including conductor replacement- cc
		$1,507	Borsa lane – transfer of overhead conductors
	Total 2007	$105,474	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1845 – underground conductors & devices	2007	$1,317	Scott street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The scott street upgrade included transformer replacement including disposal of the 3000 kva transformer, the installation of the 5000 kva transformer. Secondary switchgear replacement includes the supply and installation of four 5 kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker and four 1200 amp feeder breakers, and the supply and installation of four underground feeders. Relay protection upgrades include the replacement of existing relays with four schweitzer protection and breaker control relays. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-04 – scott street substation.
		$18,115	Tiffin plaza – labour and materials to complete underground project at tiffin plaza - cc
		$16,867	Blockbusters - labour and materials to complete underground project at blockbuster plaza- cc
		$12,053	Super 8 motel - labour and materials to complete underground project at hugel & penetanguishene rd- cc
		$8,797	Bayview school - labour and materials to complete underground project at bayview school- cc
		$8,688	Huron park - labour and materials to complete underground project at huron park- cc

		$770	William street - labour and materials to complete underground project at 447 william street
		$864	Borsa lane – pole construction and underground work
	Total 2007	$67,471	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1850 – line transformers	2007	$468	Project is to provide a loop feed back-up to an existing pad-mount transformer on bourgeois lane at the rear of the bell canada building. The scope of this project involves pole configuration and placing primary conductor between to pad mount transformers located beside one another. At the completion of this project, the existing radial feed will be replaced with a loop feed, thereby improving reliability of power to our customers. In addition, the operations department will have the ability to balance existing circuit loads
		$7,109	Purchase of transformer for bourgeois lane kiosk
		$7,106	Refurbishment of transformers that are forecasted to be returned from the field. Refurbishing transformers is an economical way of providing transformers to customers requiring temporary power (i.e. Construction trailers).
		$41,710	Distribution transformer purchases throughout the year
		$5,308	Purchase of three pole mount transformers
		$4,912	Transformer for whitney crescent- cc
		$17,729	Tiffin plaza transformer- cc
		$10,774	Blockbuster transformer- cc
		$17,924	Super 8 motel transformer- cc
		$17,729	Bayview school transformer- cc
		$6,298	Meatland transformer- cc
		$3,195	Dr. Avidar transformer- cc
	Total 2007	$140,263	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1925 - software	2007	$141,853	Software conversion from advanced utility systems to harris to effect the change in billing software. Costs include harris project management and integration, software/hardware support, conversion of data from advanced software to harris software, training of mpuc staff. Mpuc will need to upgrade internet access to access the harris billing configurations as well. This will include fiber installation and set-up costs. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-01 – billing software.
		$4,417	Server backup software upgrades, financial statement software – accpac upgrades, purchase of adobe acrobat,

	Total 2007	$146,271	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1930 transportation equipment	2007	$151,987	Truck #2 (1995 ford single bucket truck) replacement. The town of midland fleet manager recommends truck# 2 for immediate replacement. An independent vehicle inspection report, performed in barrie, reveals a number of repairs would be needed to pass inspection. The maintenance and service incurred with this vehicle over the past few years indicates costly repairs will continue. The vehicle body has considerable surface and undercarriage rusting in several locations. The driver and passenger seat is missing vinyl covering, resulting in the loss of cushioning material for proper driving posture. The altec service advisor has submitted an inspection report on the hydraulic boom system recommending the system be replaced. The vehicle is currently not equipped with air bags or abs. Cost = $132,987.28. Truck #1 cost adjustment in 2007 to reflect trade-in allowance on truck purchased in 2006 = $19,000.00. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2007-05 – purchase of bucket truck.
	Total 2007 additions	$151,987	Total additions per the gross capital assets table
	2007 retirement	-$67,942	Disposal of truck #2 – as shown in column retirements/other per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1995 – contributions and grants	2007	$33,096	Amortization
	2007 additions	-$6,909	New services
		-$7,377	Prospect blvd. Install poles
		-$4,912	Whitney crescent transformer
		-$3,156	Overhead service at torza top
		-$3,848	Pole installation at 716 ontario
		-$6,333	New service 484 dominion avenue
		-$1,308	Installation of poles – easy street
		-$35,844	Tiffin plaza transformer job
		-$27,641	Blockbuster transformer job
		-$17,304	Pillsbury drive – extend primary cable
		-$17,531	General mills – relocate 44kv
		-$40,533	Super 8 motel – transformer job
		-$26,526	Bayview school – transformer job

		-$12,342	Noack – relocate primary feed & transformer bank
		-$8,688	Huron park – primary 3 phase pole riser installation
		-$9,589	343 midland avenue – transformer job
		-$28,591	Little lake park – pole installation
	Total 2007 additions	-$258,431	
	2007	$6,538	Error in posting – posting of developer contributions was corrected in 2008 by posting to asset; posting of contracted labour recoverable was corrected in 2008 by posting to jobbing.
	Total 2007	-218,797	Net additions for 2007 per the gross capital assets table

Reconciliation to B1 Gross Capital Assets Table

Capital Additions, Retirements/Other are as set out on the Gross Capital Assets Table. Account variances greater than 1% have been explained above. Those additions with a variance of less than 1% represent miscellaneous additions to the USofA numbers as follows:

Acct # & name	Year	Amount	Description of addition
#1808 - buildings & fixtures	2007	$37,224	Additions throughout 2007 include installation of a new quanset hut, flag pole installation and upgrades. . This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1855 - services	2007	$46,599	Additions throughout 2007 include new connections throughout the year of which $32,683 were contributed capital (cc) projects. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1860 – meters	2007	$18,818	Additions throughout 2007 include the purchase of meters throughout the year and the supply of ieso registration & commissioning at the waubaushene ts 98m2 pme1. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1915 – office furniture & equipment	2007	$8,748	Additions throughout 2007 include the purchase of a plotter and filing cabinet. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1920 – computer equipment	2007	$14,388	Additions throughout 2007 include the purchase of a server and ups. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1940 – tools, shop & garage equipment	2007	$33,125	Additions throughout 2007 include the purchase of a snow blower, cable height meter, chainsaw, set of house to house jumpers, 30 meter extension sow cable, steel pallet racking, locator kit and rd4000 kit a frame, bag receiver. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1980 system supervisory equipment	2007	$22,117	Additions throughout 2007 include the purchase of a 900 mhz licenced radio, intermediate arrester, poles and installation of lighting arrestors on 44kv line. This amount is shown on the additions column per the gross capital assets table

Historical Actual to Bridge – 2007 Actual to 2008 Bridge

Actual ending balance for Capital Assets as at December 31, 2007 is $15,995,366 vs. Budgeted Capital Assets at December 31, 2008 of $18,545,819. The variance, $2,550,453, is as a result of additions throughout the 2008 year.

Explanations of variances greater than the materiality level of $51,683 are as follows:

Acct # & name	Year	Amount	Description of addition
#1820 – distribution plant	2008	$1,119,900	Brandon street substation upgrade - this upgrade is a part of the distribution system upgrade planning process instituted by the substation infrastructure study done in 2006. The brandon street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-01 – brandon street substation upgrade.
		$50,000	Engineering services will be required to provide a complete substation design drawings detailing items such as schematic diagrams, elevations and grades, conduit layout, terminal pole details, ground grid design, control panel specifications etc. Construction specifications for the design of the building will also be included and will include site work, foundation, structures and assemblies, cable runs, bus work, and instrumentation. Fault current calculations, co-ordination study, ground grid study also form part of this

			work.engineering design for the relocation of the 44 kv line, the design for three new 4.16 distribution feeders and for the connections to existing feeders is included and will come with approved standards drawings.soil testing of the proposed substation site will be required.
	Total 2008	$1,169,900	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1830 – poles, towers & fixtures	2008	$2,000	Brandon street substation upgrade - this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The brandon street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-01 – brandon street substation upgrade.
		$60,000	Montreal street pole line : pole construction from fourth street to eighth street. The existing pole line is in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-02 – montreal street pole line.
		$1,100	559 king street - removal of three overhead transformers located on a concrete pad within a fenced compound and the installation of one-three phase, 200 kva pad-mount transformer. In addition, a 50 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.
		$15,200	334 king street - two 50 foot wooden utility poles, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.
		$28,500	George street – a wooden h-frame is rotting and no grounding can be found on the fenced enclosure; installation of 2 three phase overhead transformer banks. In addition, four, 45 foot wooden utility poles, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is

			provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-03 – george street – 3 phase bank.
		$45,000	Scott street pole line - replacement of 13 poles beginning at the scott st. Sub station and ending at william st. In town of midland. The existing pole line is in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-05 – scott street pole line.
		$8,400	Replace 12 selected poles throughout the town of midland in 2008 (overall project is 37 poles – 12 in 2008; 12 in 2009 and 13 in 2010) all identified poles selected are in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed as required.
		$25,000	Air break switch - replace 2 poles and an aging air brake switch located at the intersection of william & scott street in the town of midland. The existing switch is in poor condition from years of adverse weathering (rusting and oxidation present). Replacing this 44kv air brake switch will help prevent power outages to midland's large users and six substations.
		$5,000	Installation of 44kv lightening arresters (1 set of 3) on the 44kv - m2 circuit located on highway #12, west of the kindred plant. This set of arresters completes the installation of 4 planned scada arrestor installations. Three sets of arrestors were installed as part of the 2007 capital budget with the final set planned for 2008. 44kv polymer arresters protect our scada system (remote wireless monitoring of transmission circuits) from electrical surges caused by accidental circuit shorts (i.e. Lightening strikes, trees falling on wires and so on..).
		$7,000	Contracted labour costs - contractors assist with projects that midland power utility employees are not able to perform. Contracted labour is required periodically to complete projects requiring special equipment (i.e. Bombardier digger derrick, 65ft reach bucket truck) and to meet to meet aggressive capital project timelines during summer construction months.
		$6,000	Complete a 3 - phase loop of the existing distribution circuit feeding borsa lane, in the town of midland. The placement of one 50' wooden utility pole. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads and improve over-all system efficiency.

		$2,000	to secure engineering services for the approval of non-complaint construction framing drawings. As per ontario regulation 22/04, mpuc must have approved professional engineer approved drawings. Approximately 20% of the available framing configurations are not available as part of the usf (utility standards forum) esa approved drawings.
		$40,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2008, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $40,000 would be attributed to account #1830. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-06 – development contributions – economic evaluations.
		$45,040	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-07 – capital contributions – customer contributions.
	Total 2008	$290,240	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1835 - overhead conductors and devices	2008	$31,000	Montreal street conductor work - construction from fourth street to eighth street . In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. Conductor work will also include the transfer of existing wire from old poles to new poles. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-02 – montreal street pole line.
		$2,000	559 king street - removal of three overhead transformers located on a concrete pad within a fenced compound and the installation of one-three phase, 200 kva pad-mount transformer. In addition, a 50 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.
		$8,000	334 king street – removal of three overhead transformers located on a wood h-frame structure that is un-safe (rotting wood). This structure is located in a parking lot of a commercial complex. The transformers will be replaced with the installation of one, three phase, 300 kva pad-mount transformer. A 50 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches,

			grounding, u-guards, conduit and associated hardware will be installed.
		$5,000	George street – a wooden h-frame is rotting and no grounding can be found on the fenced enclosure; in addition, four, 45 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-03 – george street – 3 phase bank.
		$20,000	Scott street conductor work – replacement of 13 poles beginning at the scott st. Sub station and ending at william st. In town of midland. The 4.16kv distribution circuit will be upgraded from 1/0 to 336 mcm conductor. Conductor work will also include the transfer of existing 44 kv feeder from old poles to new poles. Existing transformer loading will be calculated and if required a rebalance of the electrical load will be undertaken within the scope of this project. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-05 – scott street pole line.
		$2,000	Replace 37 selected poles throughout the town of midland. All identified poles selected are in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed as required. Conductor work will also include the transfer of existing wire from old poles to new poles.
		$9,000	Air break switch - replace 2 poles and an aging air brake switch located at the intersection of william & scott street in the town of midland. The existing switch is in poor condition from years of adverse weathering (rusting and oxidation present). Replacing this 44kv air brake switch will help prevent power outages to midland's large users and six substations. Conductor work will also include the transfer of existing wire from old poles to new poles.
		$7,500	Contract labour and equipment for the removal of trees and overgrowth vegetation (sumac bushes and poison ivy) along the taylor field power line easement. This area is particularly difficult to access for large trucks and tree trimming equipment. Most of the taylor field easement is void of serviced roads. The taylor field power line easement houses midland puc's "m2 & m4" - 44kv transmissions lines feeding mpuc's sub stations and large users.
		$7,000	Contracted labour - contractors assist with projects that midland power utility employees are not able to perform. Contracted labour is required periodically to complete projects requiring special equipment (i.e. Bombardier digger derrick, 65ft reach bucket truck) and to meet to meet aggressive capital project timelines during summer construction months.

		$20,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2008, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $20,000 would be attributed to account #1835. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-06 – development contributions – economic evaluations.
		$ 42,460	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-07 – capital contributions – customer contributions.
	Total 2008	$153,960	Total additions per the gross capital assets table

Acct # & name	**Year**	**Amount**	**Description of addition**
#1845 – underground conductors & devices	2008	$4,000	Brandon street substation upgrade - this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The brandon street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. New distribution feeders will be installed as part of the rebuild. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-01 – brandon street substation upgrade.
		$34,000	Norman crescent – pole transformers - to replace 4 pole transformers on norman crescent in the town of midland. Streetlight pole transformers pose undue safety risks due to the close proximity of primary and secondary cable in a confined space (i.e. The hollow of a streetlight). Maintenance or emergency service work becomes quite restrictive. Cramming secondary and primary wires in a confined space within a transformer pole poses an undo electrical hazard and hence a safety risk for technicians. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-04 – norman crescent – pole transformer

			replacement.
		$13,000	Fault indicators - the installation of 50 fault current indicators (fci's) at strategic points throughout our distribution network. Fci's would be installed at underground transformers and switch gear locations. The purpose of this program is to provide our line crews with a visual mechanism when trouble shooting customer power outage calls. Power restoration timelines are reduced with the visual indicator provided on the fci unit (l.e.d. lights). Line crews can quickly ascertain which circuits are affected without leaving the patrol vehicle or opening a transformer/switch gear units.
		$5,000	Bourgeois lane – engineering: capital funds are required in 2009 ($53,100) to complete a 3 - phase loop of the existing distribution circuit feeding bourgeois lane, south of dominion avenue, in the town of midland. The project involves the removal of three overhead transformers temporarily located in a pad-mount cabinet and the installation of one, 3 – phase, 300 kva transformer. In addition, a 50' wooden utility pole and three, 100 kva pole-mount transformers will be installed on midland avenue. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads, improve over-all system efficiency and remove a potential safety hazard. Engineering funds in the amount of $5,000.00 are budgeted in 2008 for a engineered solution to this issue
		$6,000	Contracted labour - contractors assist with projects that midland power utility employees are not able to perform. Contracted labour is required periodically to complete projects requiring special equipment (i.e. Bombardier digger derrick, 65ft reach bucket truck) and to meet to meet aggressive capital project timelines during summer construction months.
		$20,900	845 king street – transformer - to replace an aging pad-mount 500kva transformer at 845 king street. The existing transformer has significant corrosion whereas a hole has developed at the front of the cabinet. This project involves replacing the 500 kava pad mount transformer and vault with a refurbished pad mount transformer, including new primary and secondary connectors.
		$25,600	To complete a 3 - phase loop of the existing distribution circuit feeding borsa lane, in the town of midland. A 500kva transformer (installed previously a few years ago) failed and will need to be replaced and repaired. Also, this project involves the installation of 150m of 500 mcm secondary conductor in existing conduits and the placement of one 50' wooden utility pole. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..).

			Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads and improve over-all system efficiency.
		$2,000	To secure engineering services for the approval of non-complaint construction framing drawings. As per ontario regulation 22/04, mpuc must have approved professional engineer approved drawings. Approximately 20% of the available framing configurations are not available as part of the usf (utility standards forum) esa approved drawings.
		$250,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2008, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $250,000 would be attributed to account #1845. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-06 – development contributions – economic evaluations.
		$ 68,280	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-07 – capital contributions – customer contributions.
	Total 2008	$428,780	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1850 – line transformers	2008	$190,100	Brandon street substation upgrade -this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The brandon street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-01 – brandon street substation upgrade.
		$8,000	Montreal street transformers: existing transformers will be upgraded and if required a re-balance of the electrical load will be undertaken within the scope of this project. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by

			project at exhibit 2, tab 3, schedule 1, as project description: #2008-02 – montreal street pole line.
		$17,000	559 king street – removal of three overhead transformers located on a concrete pad within a fenced compound and the installation of one-three phase, 200 kva pole-mount transformer. In addition, a 50 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.
		$17,000	334 king street – removal of three overhead transformers located on a wood h-frame structure that is un-safe (rotting wood). This structure is located in a parking lot of a commercial complex. The transformers will be replaced with the installation of one, three phase, 300 kva pole-mount transformer. Arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.
		$25,000	George street – removal of six overhead transformers located within a fenced compound on a concrete pad. In addition, a wooden h-frame is rotting wood and no grounding can be found on the fenced enclosure; installation of 2 three phase overhead transformer banks. In addition, four, 45 foot wooden utility pole, steel cross-arm, 1/0 stranded copper u/g conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-03 – george street – 3 phase bank.
		$15,000	Norman crescent – pole transformers - replace 4 pole transformers on norman crescent in the town of midland. Streetlight pole transformers pose undue safety risks due to the close proximity of primary and secondary cable in a confined space (i.e. The hollow of a streetlight). Maintenance or emergency service work becomes quite restrictive. Cramming secondary and primary wires in a confined space within a transformer pole poses an undo electrical hazard and hence a safety risk for technicians. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-04 – norman crescent – pole transformer replacement.
		$5,000	Scott street transformers - existing transformers will be upgraded and if required a rebalance of the electrical load will be undertaken within the scope of this project. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-05 – scott street pole line.
		$1,000	Replace 37 selected poles throughout the town of midland. All identified poles selected are in poor condition. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed as required. Transformers will be transferred from the old poles to the new poles.

		$10,000	845 king street – transformer. Replace an aging pad-mount 500kva transformer at 845 king street. The existing transformer has significant corrosion whereas a hole has developed at the front of the cabinet. This project involves replacing the 500 kava pad mount transformer and vault with a refurbished pad mount transformer, including new primary and secondary connectors.
		$2,000	To secure engineering services for the approval of non-complaint construction framing drawings. As per ontario regulation 22/04, mpuc must have approved professional engineer approved drawings. Approximately 20% of the available framing configurations are not available as part of the usf (utility standards forum) esa approved drawings.
		$60,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2008, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $60,000 would be attributed to account #1850. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-06 – development contributions – economic evaluations.
		$48,600	Refurbishment of transformers that are forecasted to be returned from the field. Refurbishing transformers is an economical way of providing transformers to customers requiring temporary power (i.e. Construction trailers).
		$83,140	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-07 – capital contributions – customer contributions.
	Total 2008	$481,840	Total additions per the gross capital assets table

Acct # & name	**Year**	**Amount**	**Description of addition**
#1855 – services	2008	$6,100	Montreal street pole line: pole construction from fourth street to eighth street – the existing pole line is in poor condition. Services will be relocated until the new pole line is constructed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-02 – montreal street pole line.
		$24,000	Norman crescent – pole transformers - replace 4 pole transformers on norman crescent in the town of midland. Services will be relocated until the new pole line is constructed. This cost forms part of one of mpuc's major

			projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-04 – norman crescent – pole transformer replacement.
		$6,000	Scott street pole line – replacement of 13 poles beginning at the scott st. Sub station and ending at william st. In town of midland. Existing services will be relocated until the new pole line is constructed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-05 – scott street pole line.
		$1,000	Replace 37 selected poles throughout the town of midland. All identified poles selected are in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed as required. Existing services will be relocated until the new pole line is constructed.
		$30,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2008, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $30,000 would be attributed to account #1855. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-06 – development contributions – economic evaluations.
		$ 34,580	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2008-07 – capital contributions – customer contributions.
	Total 2008	$101,680	Total additions per the gross capital assets table

Contributed Capital - #1995

MPUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. 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. In 2007, MPUC had capital contributions of approximately $258,000. The assets were debited depending on the type of work performed and the offsetting credit was posted to account #1995. In 2008 and 2009, MPUC expects to have $273,500 in capital contributions, split between various USoA APH accounts. Based on 2007 levels of contributions, the 2008 assets associated with the contributions are projected to fall into account numbers 1830, 1835, 1845, 1850, and 1855, as follows:

2007 Contributed Capital

Acct #	Amount	Percentage
1830	42,554.39	16.47%
1835	40,112.93	15.52%
1845	64,519.40	24.97%
1850	78,561.30	30.40%
1855	32,683.16	12.65%
	258,431.18	1.00

2008/2009 Contributed Capital

Acct #	Amount	Percentage
1830	45,040	16.47%
1835	42,460	15.52%
1845	68,280	24.97%
1850	83,140	30.40%
1855	34,580	12.65%
	273,500	1.00

Acct # & name	Year	Amount	Description of addition
#1995 – contributions and grants	2008	-$273,500	New contributed capital estimated throughout the year from various customers on small capital projects
		$37,300	Amortization
		-$236,200	Net 2008 contributed capital as shown in column additions per the gross capital assets table

Reconciliation to Gross Capital Assets Table

Capital Additions as set out on the Gross Capital Assets Table in aggregate are $2,550,453.

Account variances greater than 1% have been explained above. Those additions with variance less than 1%.represent miscellaneous additions to the USofA numbers as follows:

Acct # & name	Year	Amount	Description of addition
#1808 - buildings & fixtures	2008	$23,200	Additions throughout 2008 include signage, paving, landscaping and operations building and quanset hut upgrades. This amount is shown on the additions column in the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1860 – meters	2008	$8,100	Capital funds are required to purchase 6 test switches, 4 interval meters, 1 roll of #12 copper wire, 1 box of meter seals and rings, 15 current transformers, and 3 current clamps. Total additions in the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1920 – computer equipment - hardware	2008	$13,213	Additions throughout 2008 include the purchase of a server switch, laser printer and monitors. Total additions in the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1925 - software	2008	$14,000	Upgrade to harris billing software. Total additions in the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1930 - transportation equipment	2008	$39,900	Additions throughout 2008 include the purchase of a new vehicle for operations and the purchase of a pole trailer. Total additions in the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1940 – tools, shop and garage equipment	2008	$33,200	Additions throughout 2008 include the purchase of an outdoor propane cage, power cable locator, hydraulic hose, ladders, tool kits. Total additions in the gross capital assets table

Acct # & Name	Year	Amount	Description of Addition
#1980 – System Supervisory Equipment	2008	$28,640	Additions throughout 2008 include the purchase of system nomenclature, 3 RTU replacements, Autocad licences and Dromey short circuit program. Total Additions in the Gross Capital Assets Table

2008 Bridge Year to 2009 Test Year

The Budgeted ending balance for Capital Assets as at December 31, 2008 is $18,545,819 vs. Budgeted Capital Assets at December 31, 2009 of $21,138,579. The variance, $2,592,760 is made up of $2,746,840 in additions and the disposal of a vehicle of $154,080 throughout the 2009 year.

Explanations of variances greater than the materiality level of $51,683 are as follows:

Acct # & name	Year	Amount	Description of addition
#1820 – distribution plant	2009	$1,045,800	Fourth street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation infrastructure study done in 2006. The fourth street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors, one gang-operated load break switch and single phase fuse assemblies; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-03 – fourth street substation upgrade.
	Total 2009	$1,045,800	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1830 – poles, towers & fixtures	2009	$5,500	Fourth street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The fourth street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors, one gang-operated load break switch and single phase fuse assemblies; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This project will also include the installation of new poles. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description:

			#2009-03 – fourth street substation upgrade.
		$8,000	Replace 12 selected poles throughout the town of midland in 2008 (overall project is 37 poles – 12 in 2008; 12 in 2009 and 13 in 2010) all identified poles selected are in poor condition. Pole tops are rotting from years of adverse weather effects. Damage to poles from snow plowing operations and other vehicle mishaps contributes to the decay. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed as required.
		$23,400	Air break switch - replace 2 poles and an aging air brake switch located at fourth and ontario street. The existing switch is in poor condition from years of adverse weathering (rusting and oxidation present). Replacing this 44kv air brake switch will help prevent power outages to midland's large users and six substations.
		$40,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2009, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $40,000 would be attributed to account #1830. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-02 – development contributions – economic evaluations.
		$88,700	Yonge street pole line - replace 54 poles from county road 93 to king st. In the town of midland. The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-04 – yonge street pole line.
		$74,000	Hugel street pole line - replace 30 poles from county road 93 to eighth st. In town of midland. The existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-05 – hugel avenue pole line.
		$92,500	Sunnyside pole line rebuild - the existing pole line is in poor condition. Pole tops are rotting from years of adverse weather effects, including damage from snow plowing operations and other vehicle mishaps. Upgrade of this pole line is also required to provide the necessary capacity for future demands. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3,

			schedule 1, as project description: #2009-06 – sunnyside pole line.
		$ 45,040	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-09 – capital contributions – customer contributions.
	Total 2009	$377,140	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1835 – overhead conductors & devices	2009	$1,700	Conductor work on pole replacement project: - replace 12 selected poles throughout the town of midland. All identified poles selected are in poor condition. 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 cross arms, insulators, guying, grounding and anchoring will be placed as required. Conductors will be transferred from old poles to new poles.
		$7,800	Air break switch – replace 2 poles and an aging air brake switch located at fourth street and ontario street. The existing switch is in poor condition from years of adverse weathering (rusting and oxidation present). Replacing this 44kv air brake switch will help prevent power outages to midland's large users and six substations.
		$20,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2009, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $20,000 would be attributed to account #1835. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-02 – development contributions – economic evaluations.
		$26,000	Yonge street pole line - replace 54 poles from county road 93 to king st. In the town of midland. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Conductor work will entail transfer of existing conductors to new poles. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-04 – yonge street pole line.
		$21,000	Hugel street pole line – conductor work on replacement of 30 poles from county road 93 to eighth st. In town of midland. 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. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-05 – hugel avenue pole line.
		$46,300	Sunnyside pole line rebuild- conductor work on rebuild the sunnyside pole line. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. Upgrade of this pole line is also required to provide the necessary capacity for future demands. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-06 – sunnyside pole line.
		$ 42,460	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-09 – capital contributions – customer contributions.
	Total 2009	$165,260	Total additions per the gross capital assets table

Acct # & name	**Year**	**Amount**	**Description of addition**
#1845 – underground conductors & devices	2009	$3,500	Fourth street substation upgrade – this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The fourth street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors, one gang-operated load break switch and single phase fuse assemblies; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. The underground work will include the upsize of the feeder cable sizes. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-03 – fourth street substation upgrade.
		$11,900	Fault indicators - capital funds are required to complete the installation of 50 fault current indicators (fci's) at strategic points throughout our distribution network. Fci's would be installed at underground transformers and switch gear locations. The purpose of this program is to provide our line crews with a visual mechanism when trouble shooting

			customer power outage calls. Power restoration timelines are reduced with the visual indicator provided on the fci unit (l.e.d. lights). Line crews can quickly ascertain which circuits are affected without leaving the patrol vehicle or opening a transformer/switch gear units.
		$4,100	Bourgeois lane –: to complete a 3 - phase loop of the existing distribution circuit feeding bourgeois lane, south of dominion avenue, in the town of midland. The project involves the removal of three overhead transformers temporarily located in a pad-mount cabinet and the installation of one, 3 – phase, 300 kva transformer. In addition, a 50' wooden utility pole and three, 100 kva pole-mount transformers will be installed on midland avenue. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads, improve over-all system efficiency and remove a potential safety hazard. Engineering funds in the amount of $5,000.00 are budgeted in 2008 for a engineered solution to this issue. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-01 – bourgeois lane – replace transformer kiosk.
		$250,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2009, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $250,000 would be attributed to account #1845. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-02 – development contributions – economic evaluations.
		$40,000	A program to replace the existing kabars. Many kabars have been installed for 25 years and are now deteriorating. As the nature of the work to change a unit may vary due to unforeseen circumstances such as defective elbows, the cost to replace one kabar will vary proportionately.
		$ 68,280	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-09 – capital contributions – customer contributions.

	Total 2009	$377,780	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1850 – line transformers	2009	$180,000	Fourth street substation upgrade - this upgrade is a part of the distribution system upgrade planning process instituted by the substation study done in 2006. The fourth street upgrade includes the engineering studies – co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for esa inspections and a set of esa approved electric drawings; ground grid reconstruction; installation of three lighting arrestors, one gang-operated load break switch and single phase fuse assemblies; transformer removal and installation; secondary switchgear replacement – includes the supply and installation of three 5kv-3000 amp breaker cells, supply and installation of one 2000 amp main breaker. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-03 – fourth street substation upgrade.
		$800	Replace 12 selected poles throughout the town of midland as a part of the three year pole replacement project. Transformers will be transferred from the existing pole line to the new pole line.
		$29,000	Bourgeois lane –: to complete a 3 - phase loop of the existing distribution circuit feeding bourgeois lane, south of dominion avenue, in the town of midland. The project involves the removal of three overhead transformers temporarily located in a pad-mount cabinet and the installation of one, 3 – phase, 300 kva transformer. In addition, a 50' wooden utility pole and three, 100 kva pole-mount transformers will be installed on midland avenue. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads, improve over-all system efficiency and remove a potential safety hazard. Engineering funds in the amount of $5,000.00 are budgeted in 2008 for a engineered solution to this issue. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-01 – bourgeois lane – replace transformer kiosk.
		$60,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2009, it is estimated that mpuc will pay a transfer price of $400,000

			for the assets installed by the developer of which $60,000 would be attributed to account #1850. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-02 – development contributions – economic evaluations.
		$6,000	Yonge street pole line: to replace 54 poles from county road 93 to king st. In the town of midland. Transformers 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. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-04 – yonge street pole line.
		$4,200	Hugel street pole line: to replace 30 poles from county road 93 to eighth st. In town of midland. Transformers 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. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-05 – hugel avenue pole line.
		$15,000	Refurbish overhead transformers: to refurbish transformers that are in most cases more than half century old. Our replacement program includes transformers in stock that are defective. Each transformer will be refurbished at a cost of approximately $3,000.00 + pst. Re-conditioned transformers are an economical way of providing reliable power to our residential and commercial customers (i.e. Temporary power to construction trailers).
		$ 83,140	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-09 – capital contributions – customer contributions.
	Total 2009	$378,140	Total additions per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1855 – services	2009	$800	Replace 12 selected poles throughout the town of midland as a part of the three year pole replacement program. Existing services will be transferred from the old pole line to the new pole line. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed as required.
		$20,000	Bourgeois lane –: to complete a 3 - phase loop of the existing distribution circuit feeding bourgeois lane, south of

			dominion avenue, in the town of midland. The project involves the removal of three overhead transformers temporarily located in a pad-mount cabinet and the installation of one, 3 – phase, 300 kva transformer. In addition, a 50' wooden utility pole and three, 100 kva pole-mount transformers will be installed on midland avenue. Completion of this project will provide mpuc with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. Regular maintenance of equipment) and unplanned outages (i.e. Lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - phase looped circuit will provide mpuc with an opportunity to balance the existing loads, improve over-all system efficiency and remove a potential safety hazard. Engineering funds in the amount of $5,000.00 are budgeted in 2008 for a engineered solution to this issue. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-01 – bourgeois lane – replace transformer kiosk.
		$30,000	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 these projects and will be reduced annually during the connection horizon as connections are connected. Upon energization, which is expected in 2009, it is estimated that mpuc will pay a transfer price of $400,000 for the assets installed by the developer of which $30,000 would be attributed to account #1855. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-02 – development contributions – economic evaluations.
		$7,500	Yonge street pole line: to replace 54 poles from county road 93 to king st. In the town of midland. Existing services will be transferred from the old pole line to the new pole line. In conjunction with pole replacements, new factory spun bus secondary, cross arms, insulators, guying, grounding and anchoring will be placed. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-04 – yonge street pole line.
		$6,000	Hugel street pole line: to replace 30 poles from county road 93 to eighth st. In town of midland. Existing services will be transferred from the old 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. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-05 – hugel avenue pole line.
		$34,580	Contributed capital – customers request mpuc to complete work at their premises. Mpuc assumes responsibility for the

			assets but these capital additions are offset by capital contributions which are included in usoa number 1995. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-09 – capital contributions – customer contributions.
	Total 2009	$98,880	Total additions per the gross capital assets table

Acct # & name	**Year**	**Amount**	**Description of addition**
#1930 – transportation equipment	2009	$310,000	Truck #4 replacement: – 1990 ford double bucket truck. This truck is 18 years old. Many repairs have been done on this truck over the past few years. There have been technical problems and rusting issues. 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. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-07 – purchase of bucket truck
		$25,000	Replacement of 1997 gmc safari van. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-07 – purchase of metering van.
	Total 2009	$335,000	Total additions per gross capital assets table
		-$154,080	Total vehicle retirements per the gross capital assets table

Acct # & name	**Year**	**Amount**	**Description of addition**
#1980 – system supervisory equipment	2009	$100,000	Scada software upgrade: mpuc'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 which is similar to unix. Over the past several years, the software engineers added a scada system which operates on a windows platform. Mpuc's plan is to upgrade our current vms based scada system to the windows system. This change will not only facilitate the export of real time and historical data but will simplify operational controls. This cost forms part of one of mpuc's major projects for the year. A full description of the project is provided in the capital plan by project at exhibit 2, tab 3, schedule 1, as project description: #2009-08 – scada software upgrade.
	Total 2009	$100,000	Total additions per the gross capital assets table

1

Contributed Capital - #1995

MPUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. 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. In 2007, MPUC had capital contributions of approximately $258,000. The assets were debited depending on the type of work performed and the offsetting credit was posted to account #1995. In 2008 and 2009, MPUC expects to have $273,500 in capital contributions, split between various USoA APH accounts. Based on 2007 levels of contributions, the 2009 assets associated with the contributions are projected to fall into account numbers 1830, 1835, 1845, 1850, and 1855, as follows:

2007 Contributed Capital

Acct #	Amount	Percentage
1830	42,554.39	16.47%
1835	40,112.93	15.52%
1845	64,519.40	24.97%
1850	78,561.30	30.40%
1855	32,683.16	12.65%
	258,431.18	1.00

2008/2009 Contributed Captial

Acct #	Amount	Percentage
1830	45,040	16.47%
1835	42,460	15.52%
1845	68,280	24.97%
1850	83,140	30.40%
1855	34,580	12.65%
	273,500	1.00

Acct # & name	Year	Amount	Description of addition
#1995 – contributions and grants	2009	-$273,500	New contributed capital estimated throughout the year from various customers on small capital projects.
		$48,300	Amortization
		-$225,200	Net 2009 contributed capital per the gross capital assets table

Reconciliation to Gross Capital Assets Table

Capital Additions as set out on the Gross Capital Assets Table in aggregate are $2,746,840. Account variances greater than 1% have been explained above. Those additions with a variance of less than 1% represent miscellaneous additions to the USofA accounts as follows:

Acct # & name	Year	Amount	Description of addition
#1808 – buildings & fixtures	2009	$35,000	Additions throughout 2009 include paving the operations yard and renovations to the quanset hut ventilation and exhaust system. Cool air and hot exhaust need to be renovated to comply with moe guidelines. This amount is shown on the additions column per the gross capital assets table

Acct # & Name	Year	Amount	Description of Addition
#1860 – Meters	2009	$10,000	Capital funds are required to purchase test switches, interval meters, copper wire, meter seals and rings, current transformers, power transformers and current clamps. This amount is shown on the Additions Column per the Gross Capital Assets Table

Acct # & Name	Year	Amount	Description of Addition
#1920 – Computer Hardware	2009	$19,040	Additions throughout 2009 include the purchase of new computers to replace 5 year old systems and the purchase of a laser printer (printer is over 8 years old). This amount is shown on the Additions Column per the Gross Capital Assets Table

Acct # & name	Year	Amount	Description of addition
#1925 – computer software	2009	$20,000	Additions throughout 2009include the purchase of job costing module for accpac financial software to allow computerized tracking of jobbing. This amount is shown on the additions column per the gross capital assets table

Acct # & name	Year	Amount	Description of addition
#1940 – tools, shop and garage equipment	2009	$10,000	Additions throughout 2009 include the purchase of tools for operations department. This amount is shown on the additions column per the gross capital assets table

Accumulated Amortization Table

Included on the next page is the Amortization of Capital Assets Table. This table sets out the amortization balance, the amortization expense, retirements and other adjustments by APH Account Number for the 2006 EDR Approved, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years.

Amortization of Capital Assets Table

Capital Asset Account	2006 EDR Approved	Variance to 2006 Actual: Amortization Expense	Variance to 2006 Actual: Retirements / Other	Variance to 2006 Actual: Ending Balance	2006 Actual Ending Balance	2007 Actual: Amortization Expense	2007 Actual: Retirements / Other	2007 Actual: Ending Balance
1610-Miscellaneous Intangible Plant								
1805-Land								
1806-Land Rights	-15,060	-0		-15,060	-15,060			-15,060
1808-Buildings and Fixtures	-236,926	-41,481	-13,155	-291,562	-291,562	-28,031		-319,592
1810-Leasehold Improvements								
1815-Transformer Station Equipment - Normally Primary above 50 kV								
1820-Distribution Station Equipment - Normally Primary below 50 kV	-757,771	-49,631	-12,035	-819,437	-819,437	-41,760		-861,198
1830-Poles, Towers and Fixtures	-1,295,265	-207,179	-31,806	-1,534,250	-1,534,250	-94,944		-1,629,194
1835-Overhead Conductors and Devices	-851,330	-129,489	-20,881	-1,001,700	-1,001,700	-46,517		-1,048,217
1840-Underground Conduit								
1845-Underground Conductors and Devices	-1,369,793	-199,889	-46,506	-1,616,188	-1,616,188	-98,147		-1,714,334
1850-Line Transformers	-1,281,147	-147,757	-34,639	-1,463,543	-1,463,543	-78,303		-1,541,845
1855-Services		-1,961		-1,961	-1,961	-1,742		-3,703
1860-Meters	-497,579	-11,902	-14,350	-523,831	-523,831	-34,720		-558,550
1875-Street Lighting and Signal Systems		-2,596		-2,596	-2,596	189		-2,407
1905-Land								
1906-Land Rights								
1908-Buildings and Fixtures								
1910-Leasehold Improvements								
1915-Office Furniture and Equipment	-184,705	-14,370	-3,750	-202,825	-202,825	-6,121		-208,945
1920-Computer Equipment - Hardware	-282,922	-51,876	-13,876	-348,674	-348,674	-11,875		-360,549
1925-Computer Software	-19,229	-39,656	-6,311	-65,196	-65,196	-36,943		-102,139
1930-Transportation Equipment	-684,348	-48,848	244,814	-488,381	-488,381	-48,929	67,942	-469,368
1935-Stores Equipment	-7,796	-246	-199	-8,241	-8,241	-123		-8,364
1940-Tools, Shop and Garage Equipment	-165,611	-65,006	0	-230,616	-230,616	-3,863		-234,479
1945-Measurement and Testing Equipment	-2,439	2,439						
1950-Power Operated Equipment								
1955-Communication Equipment	-108,477	39,393	-6,988	-76,073	-76,073	-3,791		-79,864
1960-Miscellaneous Equipment	-18,049	16,127	0	-1,922	-1,922	-592		-2,514
1965-Water Heater Rental Units								
1970-Load Management Controls - Customer Premises								
1975-Load Management Controls - Utility Premises								
1980-System Supervisory Equipment	-125,598	-49,098	-8,998	-183,694	-183,694	-20,800		-204,494
1985-Sentinel Lighting Rental Units								
1990-Other Tangible Property								
1995-Contributions and Grants - Credit		70,781	-70,781			33,096	-33,096	0
2005-Property Under Capital Leases								
TOTAL	**-7,904,045**	**-932,243**	**-39,462**	**-8,875,750**	**-8,875,750**	**-523,913**	**34,847**	**-9,364,816**
Accumulated Amortization on Balance Sheet	-7,904,045	1.1600-Accumulated Amortization		-8,875,750	1.1600-Accumulated Amortization			
Amortization Expense Adjustment								
Amortization Expense						**523,913**		

Amortization of Capital Assets Table

Capital Asset Account	2007 Actual Ending Balance	2008 Projection Amortization Expense	2008 Projection Retirements / Other	2008 Projection Ending Balance	2008 Projection Ending Balance	2009 Projection Amortization Expense	2009 Projection Retirements / Other	2009 Projection Ending Balance
1610-Miscellaneous Intangible Plant								
1805-Land								
1806-Land Rights	-15,060			-15,060	-15,060			-15,060
1808-Buildings and Fixtures	-319,592	-29,541		-349,133	-349,133	-30,996		-380,129
1810-Leasehold Improvements								
1815-Transformer Station Equipment - Normally Primary above 50 kV								
1820-Distribution Station Equipment - Normally Primary below 50 kV	-861,198	-79,444		-940,641	-940,641	-123,758		-1,064,399
1830-Poles, Towers and Fixtures	-1,629,194	-101,090		-1,730,283	-1,730,283	-110,905		-1,841,189
1835-Overhead Conductors and Devices	-1,048,217	-50,326		-1,098,543	-1,098,543	-55,212		-1,153,755
1840-Underground Conduit								
1845-Underground Conductors and Devices	-1,714,334	-105,776		-1,820,110	-1,820,110	-121,907		-1,942,016
1850-Line Transformers	-1,541,845	-90,745		-1,632,590	-1,632,590	-107,945		-1,740,535
1855-Services	-3,703	-4,708		-8,411	-8,411	-8,719		-17,129
1860-Meters	-558,550	-35,258		-593,808	-593,808	-35,620		-629,428
1875-Street Lighting and Signal Systems	-2,407			-2,407	-2,407			-2,407
1905-Land								
1906-Land Rights								
1908-Buildings and Fixtures								
1910-Leasehold Improvements								
1915-Office Furniture and Equipment	-208,945	-6,476		-215,421	-215,421	-6,425		-221,846
1920-Computer Equipment - Hardware	-360,549	-11,337		-371,886	-371,886	-12,334		-384,220
1925-Computer Software	-102,139	-49,766		-151,905	-151,905	-48,147		-200,052
1930-Transportation Equipment	-469,368	-61,853		-531,220	-531,220	-83,688	154,080	-460,827
1935-Stores Equipment	-8,364	-123		-8,487	-8,487	-123		-8,610
1940-Tools, Shop and Garage Equipment	-234,479	-7,179		-241,658	-241,658	-9,339		-250,997
1945-Measurement and Testing Equipment								
1950-Power Operated Equipment								
1955-Communication Equipment	-79,864	-2,799		-82,663	-82,663	-1,992		-84,655
1960-Miscellaneous Equipment	-2,514	-592		-3,106	-3,106	-592		-3,698
1965-Water Heater Rental Units								
1970-Load Management Controls - Customer Premises								
1975-Load Management Controls - Utility Premises								
1980-System Supervisory Equipment	-204,494	-22,492		-226,985	-226,985	-26,024		-253,009
1985-Sentinel Lighting Rental Units								
1990-Other Tangible Property								
1995-Contributions and Grants - Credit	0	37,321	-37,321	0	0	48,300	-48,300	0
2005-Property Under Capital Leases								
TOTAL	**-9,364,816**	**-622,181**	**-37,321**	**-10,024,319**	**-10,024,319**	**-735,424**	**105,780**	**-10,653,963**
Accumulated Amortization on Balance Sheet	-9,364,816	1.1600-Accumulated Amortization						
Amortization Expense Adjustment								
Amortization Expense		**622,181**				**735,424**		

Materiality Analysis on Accumulated Amortization

The calculation of the Materiality Threshold on Gross Assets is shown in the following table:

Table 20 Materiality Threshold on Gross Assets

	EDR – 2006	Actual - 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross Cost	$13,072,370	$14,611,472	$15,995,366	$18,545,819	$21,138,579
Accumulated Amortization	$ 7,904,045	$ 8,875,750	$ 9,364,816	$10,024,319	$10,653,963
Net Fixed Assets	$ 5,168,325	$ 5,735,722	$ 6,630,550	$ 8,521,501	$10,484,616
Percent	1%	1%	1%	1%	1%
Threshold	$51,683	$57,357	$66,305	$85,215	$104,846

The Amortization of Capital Assets Table provides a summary of Accumulated Amortization Balances per USofA account beginning with the 2006 EDR Approved Balances. The summary includes the Amortization Expense, Retirements/Other and Ending Balances for the years 2006, 2007, and 2008 Bridge Year and 2009 Test Year. This Table will be referred to in the following Accumulated Amortization analysis.

Table 21 Actual 2006 to 2006 EDR Historical Board Approved

Description	2006 Actual	2006 EDR	Variance
Accumulated Amortization	**-$8,875,750**	**-$7,904,045**	**-$971,705**
Cost Drivers:			
2006 EDR Averaging			$218,520
2005/2006 Amortization Expense			$932,242
Acct #1930 – Vehicle - Truck Disposal			-$249,838
Acct #1995 - Contributions & Grants			$70,781
Unexplained Variance			0.00

Explanation:

The 2006 Board Approved EDR balance was generated in the EDR filing based on an averaging of 2003 and 2004 balances which is $218,520 less than the 2004 actual balance. Amortization Expense for the years 2005 and 2006 totalled $932,243 (2005 = $434,412; 2006 = $497,831). The 2005 and 2006 amortization expense is calculated based on assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2006 the accumulated amortization on a truck disposal was removed from Account #1930 Transportation Equipment. The balance of $70,781 is a reduction to Account #1995, Contributions & Grants as a result of the amortization of Contributions and Grants. MPUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001.

Table 22 2007 Actual Year to 2006 Actual Year

Description	2007 Actual	2006 Actual	Variance
Accumulated Amortization	$9,364,816	-$8,875,750	-$489,067
Cost Drivers:			
2007 Amortization Expense			$523,913
Acct #1930 – Vehicle - Truck Disposal			-$67,942
Acct #1995 - Contributions & Grants			$33,096
Unexplained Variance			0.00

Explanation:

Amortization Expense for the year 2007 totalled $523,913 which is an increase over 2006 levels ($497,831) of $26,082. The 2007 amortization expense is calculated based on assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2007 the accumulated amortization on two truck disposals was removed from Account #1930Transportation Equipment in the amount of $67,942. The balance of the variance of $33,096 is a reduction to Account #1995, Contributions & Grants as a result of the amortization of Contributions and Grants. MPUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001.

Table 23 2008 Bridge Year to 2007 Actual Year

Description	**2008 Bridge Year**	**2007 Actual**	**Variance**
Accumulated Amortization	$10,024,319	$9,364,816	-$659,503
Cost Drivers:			
2008 Amortization Expense			$622,181
Acct #1995 - Contributions & Grants			$37,321
Unexplained Variance			0.00

Explanation:

Projected Amortization Expense for the year 2008 is $622,181 which is an increase over 2007 levels ($523,913) of $98,268. The 2008 amortization expense is calculated based on assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2008 there are no projected disposals of assets. The balance of the variance of $37,321 is a reduction to Account #1995, Contributions & Grants as a result of the amortization of Contributions and Grants. MPUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001.

Table 24 2009 Test Year to 2008 Bridge Year

Description	**2009 Test Year**	**2008 Bridge Year**	**Variance**
Accumulated Amortization	$10,653,963	$10,024,319	-$629,644
Cost Drivers:			
2009 Amortization Expense			$735,424
Acct #1930 – Vehicle - Disposal			-$154,080
Acct #1995 - Contributions & Grants			$48,300
Unexplained Variance			0.00

Explanation:

Projected Amortization Expense for the year 2009 is $735,424 which is an increase over 2008 levels ($622,181) of $113,243. The 2009 amortization expense is calculated based on assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset and in 2009 the accumulated amortization on a truck disposal was removed from Account #1930 Transportation Equipment in the amount of $154,080. The balance of the variance of $48,300 is a reduction to Account #1995, Contributions & Grants as a result of the amortization of Contributions and Grants. MPUC records the amortization on Contributions and Grants as a decrease to the Contribution and Grants asset account #1995 and a decrease to Amortization Expense in accordance with the process as set out in the Frequently Asked Questions of the APH dated December, 2001.

Capital Plan

Capital Plan by Project

This section provides an analysis on MPUC's Capital Plan Projects. The analysis starts with the 2006 EDR Balances and provides information on the 2005, 2006 and 2007 actual year additions, retirements and other adjustments, the 2008 Bridge Year additions and the 2009 Test Year additions and retirements. Major Capital Projects are discussed in detail and a summary of the remaining Capital Projects follows. As indicated in Exhibit 2, Tab 2, Schedule 3 an analysis by APH USoA number for each of the years was completed. Included in this analysis are costs attributed to the Capital Projects. Reference is made in the Capital Projects, where applicable, to the USoA number analysis and alternatively, is made, where applicable, in the USoA number analysis to the major Capital Projects.

The major Capital Projects are numbered according to the year in which they occurred. For example, the first project in 2005 is the 44 kv Distribution System. This project is described as #2005-01 - 44kV Distribution System. The next Project would be described as #2005-02, etc. In 2006, the numbering system would be #2006-01, #2006-02, etc. and so on for each of the subsequent years. These Capital Projects are then broken down into costs per APH USoA numbers.

Those Capital Projects greater than 1% of net fixed assets have been explained in detail. Those Captial Projects less than 1% of net fixed assets have been summarized.

Contributed Capital: Customers request MPUC to complete work at their premises. MPUC assumes responsibility for the assets but these capital additions are offset by capital contributions which are included in USoA Number 1995 – Contributed Capital. MPUC increases the asset account number and records the corresponding credit to Contributed Capital Account #1995. Contributed Capital asset additions are identified by "CC" after the description of the addition on both Exhibit 2, Tab 2, Schedule 3 and Exhibit 2, Tab 3, Schedule 1.

MPUC has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. MPUC completes ground inspections throughout the year while completing maintenance on the distribution system. In addition, MPUC relies on the substation study completed in 2006 that has provided a comprehensive analysis of the substation infrastructure within MPUC's distribution area. MPUC's distribution system includes six substations, four of which are over 50 years old and are in need of replacement due to their age. The replacement of these substations will take into consideration the potential for future growth, however, the replacement is undertaken due to the aging infrastructure.

The following is a listing of the SAIDI, SAIFI and CAIDI indices for the years 2003 to 2007 inclusive

	SAIDI	**SAIFI**	**CAIDI**
2003	4.34	1.51	2.87
2004	0.11	0.08	1.41
2005	5.78	1.57	3.68
2006	2.32	2.12	1.10
2007	1.64	0.50	3.29

These reliability indicies are recorded and monitored on an annual basis. They are used to monitor the reliability of the MPUC system and assist in the assessment of the MPUC asset condition which impacts the capital budgeting process.

MPUC has an obligation to serve new growth within our service area in a timely and cost effective way. In order to fulfill this obligation, MPUC 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 that we may face. Nevertheless, we recognize that it is unlikely that all of the plans that developers have in our service area will proceed as quickly as expected. Our capital budget reflects the level of growth that 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 2008 and 2009, it is estimated MPUC will pay a transfer price of for the assets installed by the developer.

MPUC 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. MPUC'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 MPUC 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 MPUC's distribution system are made.

Major Capital Projects:

The following section of the Application is a breakdown of major capital projects for 2005, 2006 and 2007, projected capital projects for 2008 Bridge Year and projected capital projects for 2009 Test Year.

The calculation of the materiality level as set out in the Filing Guidelines is 1% of net fixed assets. The calculation of the Materiality Threshold on Net Assets is shown in the following table:

Table 25 Materiality Threshold on Net Assets

	EDR – 2006	Actual - 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross Cost	$13,072,370	$14,611,472	$15,995,366	$18,545,819	$21,138,579
Accumulated Amortization	$ 7,904,045	$ 8,875,750	$ 9,364,816	$10,024,319	$10,653,963
Net Fixed Assets	$ 5,168,325	$ 5,735,722	$ 6,630,550	$ 8,521,501	$10,484,616
Percent	1%	1%	1%	1%	1%
Threshold	$51,683	$57,357	$66,305	$85,215	$104,846

MPUC has selected the lowest materiality threshold of $51,683 to allow for the most detailed review of capital projects. Details for each capital project exceeding the materiality threshold are presented below. Costing of each of these capital projects is broken down by APH USoA numbers. In addition, a summary is provided at the end of each year of those projects that are not considered major but form part of the overall capital additions.

2005 Year

Total capital additions for the 2005 year were $542,060. Those Projects exceeding the materiality threshold of $51,683 are as follows:

No.	Project Description	Amount
#2005-01	44kV Distribution System	$328,389
#2005-02	Kabar Replacements	$ 51,322
	TOTAL PROJECTS EXCEEDING MATERIALITY	**$379,711**

Project Description: #2005-01 - 44 kV Distribution System:

Need: The 44 kV pole line along the south side of Highway 12 from Kindred to Huronia Precision Plastics was in need of replacement. It carries the 98-M2 feeder, which is one of the two main feeders in Town, and has two 4.16/.4 kV distribution circuits. The demand has increased with the construction of Wal-Mart and the future commercial development. Increased loads on this feeder will also occur as Kindred, Georgian College (IRDI), Huronia Precision Plastics and St. Theresa's High School upgrade their services.

Scope: This pole line has been installed for many years and needs to be upgraded. The poles and wood cross arms are in bad condition. Also, the existing conductor, which is a 1/0 ACSR (aluminum conductor steel reinforced), must be upgraded to 336mcm (circular mils) to accommodate the future loads. Labour costs will be incurred to transfer the transformers from the old poleline to the new poleline. The demand has increased with the construction of Wal-Mart and the future commercial development. Increased loads on this feeder will also occur as Kindred, Georgian College (IRDI), Huronia Precision Plastics and St. Theresa's High School upgrade their services.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$324,239
#1835 – Overhead Conductors & Devices	$ 3,701
#1850 – Line Transformers	$ 449
Total Project Cost	$328,389

Start Date: July, 2005

In-Service Date: December, 2005

Project Description: #2005-02 - Kabar Replacements

Need: A program to replace the existing kabars (primary switching junction) was implemented in 2005. Many kabars have been installed for 25 years and are now deteriorating. As the nature of the work to change a unit may vary due to unforeseen circumstances such as defective elbows, the cost to replace one kabar will vary proportionately.

Scope: replacement of kabars on deteriorating infrastructure

Capital Costs:

Acct # & Description	Amount
#1845 – Undergrnd Conductors/Devices	$51,322
Total Project Cost	$51,322

Start Date: August, 2005

In-Service Date: November, 2005

Reconciliation to Total 2005 Capital Additions:

Other Projects that did not exceed the materiality level of 1% have been explained in Exhibit 2, Tab 2, Schedule 3 in the USoA Numbers as set out therein. These Projects are as follows:

No.	Project Description	Amount
#2005-03	Computer Software and & Hardware	$ 7,336
#2005-04	Old Penetanguishene Road – feeder tie line between Hugel and Yonge Street – Expansion	$ 18,960
#2005-05	Johnson Street Feeder – Enhancement	$ 23,450
#2005-06	Yonge & Queen Pole Change	$ 5,206
#2005-07	Hillcrest Lane Pole Change and Feeder	$ 1,258
#2005-08	Dorion Street Feeder	$ 16,765
#2005-09	Meter purchases	$ 7,950
#2005-10	Distribution Transformers	$ 13,151
#2005-11	Scada System	$ 810
#2005-12	Quanset Hut renos	$ 4,000
#2005-13	Brandon Substation – switching cable work	$ 5,429
#2005-14	Montreal Substation dip pole structures	$ 7,225
#2005-15	Fourth Street Substation – feeder	$ 11,214
#2005-16	Radios for new truck	$ 1,026
#2005-17	Bourgeois Lane Work	$ 1,025
#2005-18	Stock transformers	$ 7,326
#2005-19	William Street Pole change	$ 5,868
#2005-20	Scully's Pole installation	$ 2,272
#2005-21	General Mills – pole change	$ 3,500
#2005-22	New desk & filing cabinet	$ 2,314
#2005-23	New tools	$ 2,155
#2005-24	Wire for Dorion & Colborne Project	$ 5,086
#2005-25	Transformers	$ 8,415
#2005-26	Queen Street dip pole upgrades to substation	$ 609
	TOTAL Variance Less than 1%	$162,350
	TOTAL Variance Greater than 1%	$379,711
	TOTAL ADDITIONS 2005	**$542,061**

2006 Year

Capital Projects – Substations:

MPUC has six substations, four of which are over 50 years old. Due to the aging infrastructure, MPUC determined that a plan needed to be implemented dealing with the replacement of the substations to ensure the safety and reliability of the infrastructure was maintained, and in 2006, Rondar Engineering completed an assessment of the substation infrastructure. Rondar has been completing the maintenance on MPUC substations over the past 10 years and is familiar with the transformer condition and breaker relay systems of the substations. Having completed the regular maintenance on the substations, it made sense to have Rondar do a thorough investigation and provide a report giving specifications and system requirements. Rondar has a proven record with MPUC, they know the equipment and are familiar with MPUC's distribution system whereas a new contractor would have a learning curve, which may jeopardize the safety and reliability of the substations. A new contractor does not have a proven record with MPUC.

MPUC's current plan is to replace one substation per year in each of the years 2007, 2008, 2009, 2010 and in 20011 the two newer stations – Montreal and Queen would be combined. The Scott Street substation was completed in 2007. Brandon is slated for replacement in 2008 with Fourth Street following in 2009. Although this plan may seem aggressive, the safety and reliability of the distribution system will be at risk if the substation projects are put off to another year. If one project is put off, this will lead to a backlog of infrastructure replacements in the same year. In addition, if there is a catastrophic failure of one of the substations, the replacement in an emergency situation will be at increased costs.

The Scott Street substation underwent a tendering process for breakers and installation. Based on the results of the Scott Street installation, MPUC has retained the use of the same contractors to complete the substations in 2007 and 2008. Their performance and costs are monitored each year. Economies are gained by providing consistency in the design and installation of the substations along with keeping an inventory of spare parts.

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, MPUC 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. Rondar has been completing these studies on behalf of MPUC.

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.

Rondar provides regular maintenance reports on the substations. Copies of the 2002, 2003, 2004 and 2005 maintenance reports are found in Sections 7 and 8of the Substation Study. After completion of the substation maintenance, a list of recommendations is made that range from installing warning lights to monitoring the condition of specific equipment, to replacing parts or/cables. In consultation with the maintenance engineers, the nature of the deficiencies were such that the repairs/replacements could be performed during the next regularly scheduled maintenance period or included in the capital plan for the rebuilding of the station.

Major Capital Projects - 2006

Total capital additions for the 2006 year net of contributed capital were $1,029,368.65. Those Projects exceeding the materiality threshold of $51,000 are as follows:

No.	Project Description	Amount
#2006-01	Substation Infrastructure Study	$ 51,532
#2006-02	44kv Rebuild	$372,582
#2006-03	Wholesale Metering Points	$ 67,120
#2006-04	Purchase of Digger/Derrick Truck	$212,863
	TOTAL PROJECTS EXCEEDING MATERIALITY	**$704,097**

Project Description: #2006-01 - Substation Infrastructure Study

Need: In 2006 MPUC completed substation study that provided an analysis of existing infrastructure and a plan for the replacement taking into consideration future growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old.

Scope: The substation study has provided MPUC with a comprehensive list of specifications and analysis to enable MPUC to plan for the replacement of the infrastructure.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equip	$26,155
#1835 – Overhead Conductors & Devices	$25,377
Total Project Cost	$51,532

Start Date: Summer/Fall 2006

In-Service Date: Fall 2006

Project Description: #2006-02 - 44kv Rebuild

Need: Subprojects 1, 2, & 3 were necessary as a preventative measure to reduce the high probability of power outages caused by the aging effect of the wood poles and wood cross arms, and as a measure to prevent hazardous situations from occurring for the line crew and the public.

Scope:

Subproject #1 - The 44 KV rebuild that includes pole line reconstruction on Gloucester St. between Russell St. and Charles St..

Subproject #2 – The 44 KV rebuild that includes pole line reconstruction on William St. between Gloucester St. and Bay St..

Subproject #3 – The reconstruction of the 44 KV Rebuild by McNamara Powerlines has been estimated in three parts.

The reconstruction of the 44 KV pole line along the Rotary Trail from Manly to Victoria

The reconstruction of the section of line that runs from the run off at ADM Milling, through the Timber Mart lumber yard then to Fourth Street.

The installation of two air break switches. One to be installed at Manly St. and Bayshore Dr., and the other at Highway 12 and Kindred Road.

Capital Costs:

Acct # & Description	Amount
#1830–Poles, Towers & Fixtures	
#1 Gloucester between Russell& Charles	$ 18,288
#2 William St between Gloucester & Bay	$ 32,772
#3 Bayshore Drive	$321,522
Total Project Cost	$372,582

Start Date: March, 2006

In-Service Date: December, 2006

Project Description: #2006-03 - Wholesale Metering Points

Need: Market Participants were required, by the IESO, to upgrade/replace existing non-conforming meter installations and assume ownership.

Scope: The wholesale meters to be replaced in 2006 are the primary meters on the 98-M2 and the 98-M4.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 1,046
#1860 – Meters	$66,020
#1855 – Services	$ 54
Total Project Cost	$67,120

Start Date: February, 2006

In-Service Date: December, 2006

Project Description: #2006-04 - Purchase of Digger/Derrick Truck

Need: The current digger/derrick truck is a 1991 with a Ford Chassis. It is 14 years old and is the only workhorse of the fleet. This is the only vehicle that does all the heavy lifting – install/remove poles and transformers, and is used for tension pulling conductors. Two thirds of the deck floor was replaced in early 2005 and the electric controls for the digger have been causing many problems. This truck has reached the end of its useful life.

Scope: A 2007 International Digger/Derrick was purchased

Capital Costs:

Acct # & Description	Amount
#1930 – Transportation Equipment	$212,863
Note: in 2006 the amount recorded was shown net of the trade-in value of the old truck and should have been shown at its full cost. This value ($19,000) was adjusted in 2007. Consequently, the full cost of this vehicle is $231,862.84.	
Total Project Cost - 2006	$212,863

Start Date: January, 2006

In-Service Date: May, 2006

Reconciliation to Gross Capital Assets Table:

Other Projects that did not exceed the materiality level of 1% have been explained in Exhibit 2, Tab 2, Schedule 3 in the USoA Numbers as set out therein. These Projects are as follows:

(Note: Those projects marked “CC” represent contributed capital projects)

No.	Project Description	Amount
#2006-05	Computer Hardware	$ 8,866
#2006-06	Computer Software	$ 41,641
#2006-07	Office and building purchases	$ 10,371
#2006-08	Scott Street to Johnson St Pole Line Rebuild	$ 3,702
#2006-09	Stone for Brandon & Dorion substations	$ 8,617
#2006-10	Fault Current Indicators	$ 2,962
#2006-11	Kabar Replacement	$ 5,044

No.	Project Description	Amount
#2006-12	Distribution Transformers	$ 3,912
#2006-13	Tilt Trailer purchase	$ 6,313
#2006-14	Purchase of pick-up truck	$ 29,303
#2006-15	Meter purchases	$ 19,675
#2006-16	Tool purchases	$ 6,704
#2006-17	Scada RTU	$ 8,245
#2006-18	Generator	$ 5,442
#2006-19	Scott Street Substation	$ 2,444
#2006-20	Line Transformers	$ 24,383
#2006-21	Lift Truck	$ 11,556
#2006-22	Griffin Street/Cty Road #93 Pole	$ 950
#2006-23	Gervais Street Pole Line	$ 8,935
#2006-24	Pillsbury & Trilet Pole Line	$ 6,168
#2006-25	Pole purchases	$ 2,607
#2006-26	Bay Street Pole Line	$ 5,512
#2006-27	Cranston Crescent Pole Line	$ 1,780
#2006-28	Little Lake, Yonge Street, George Street Pole lines	$ 5,444
#2006-29	Paving	$ 950
#2006-30	Smart Meter Purchase thru CDM Third Tranche	$ 25,233
#2006-31	Infrared study	$ 2,506
#2006-32	Georgian College – Prospect Blvd - CC	$ 4,046
#2006-33	New Services - CC	$ 11,955
#2006-34	MapleDawn Subdivision installation of Kabars- CC	$ 3,379
#2006-35	Mundy’s Bay Condo Development Kabars- CC	$ 694
#2006-36	Mundy’s Bay Condo Development Kabars- CC	$ 764
#2006-37	Mundy’s Bay Condo Development Kabars- CC	$ 1,310
#2006-38	Mundy’s Bay Condo Development Pole Line- CC	$ 6,347
#2006-39	Aberdeen – energize new plant & install cable- CC	$ 1,250
#2006-40	St. Theresa’s School – pole construction- CC	$ 16,658
#2006-41	Tiffin Place – underground construction- CC	$ 19,019
#2006-42	Vindin Street Transformer- CC	$ 911

No.	Project Description	Amount
#2006-43	Vindin Street Transformer- CC	$ 12,201
#2006-44	Curling Club – pole construction- CC	$ 2,026
#2006-45	Well #7 Hwy 12 – install 3 phase transformer bank- CC	$ 7,139
#2006-46	Pumphouse – primary cables- CC	$ 1,133
#2006-47	Spahr – pole construction- CC	$ 2,543
#2006-48	Midland Car Wash – transformer and new service- CC	$ 18,578
#2006-49	Streetlights –new conductor- CC	$ 1,115
#2006-50	Pole Construction – Latter Day St. Church- CC	$ 5,829
#2006-51	Timberridge Development – William Street U/G- CC	$ 13,532
#2006-52	Sparkling Cherry – new service & wire inst'n- CC	$ 1,322
#2006-53	New Services- CC	$ 1,963
#2006-54	Pole construction – Wilson- CC	$ 2,805
#2006-55	Smith's Trailer Park – replace poles- CC	$ 4,210
#2006-56	County Rd #93 – Sarjeant's – pole replacement- CC	$ 1,850
#2006-57	Little Lake Park – pole installation- CC	$ 8,282
#2006-58	New Service – Weld Tek – William Street- CC	$ 11,355
#2006-59	Badger pole contract	$ 874
	TOTAL Variance Less than 1%	$ 422,355
	TOTAL Variance Greater than 1%	$ 704,097
	TOTAL ADDITIONS 2006	$1,126,452
	Contributed Capital – net	$-97,083
	Net 2006 Additions	$1,029,369
	Net 2005 Additions from above	$ 542,060
	Net 2005/2006 Additions – per Gross Capital Assets Table	**$1,571,429**

2007 YEAR

Total capital additions net of contributed capital for the 2007 were $1,451,837. Those Projects exceeding the materiality threshold of $51,683 are as follows:

No.	Project Description	Amount
#2007-01	Billing Software	$ 142,024
#2007-02	Queen Street Rebuild – Gloucester to Yonge Streets	$ 77,374
#2007-03	Tiffin Park 44kv Pole & ABS Replacement – Enhancement	$ 57,878
#2007-04	Scott Street Substation	$ 691,737
#2007-05	Purchase of Bucket Truck	$ 132,987
	TOTAL PROJECTS EXCEEDING MATERIALITY	**$1,102,000**

Project Description: #2007-01 - Billing Software

Need: In the spring of 2006, MPUC was informed by their billing software provider, Advanced CIS, that the next version of software would necessitate additional costs of over $50,000, along with their regular yearly maintenance costs. MPUC determined that the costs of the Advanced CIS were climbing and decided to look at other alternatives for their CIS system. The decision to convert their billing software to the Harris Computer NorthStar billing software was made in May, 2006. Later that summer, we were advised that Harris Computer Systems purchased Advanced CIS, and in January 2007 Harris informed the Advanced customer base that the Advanced program would not be supported beyond December, 2008.

Scope: Software conversion from Advanced Utility Systems to Harris to effect the change in billing software. Costs include, Harris project management and integration, software/hardware support, conversion of data from Advanced software to Harris software, training of MPUC staff. MPUC will need to upgrade internet access to access the Harris billing configurations as well. This will include fiber installation and set-up costs. The installation of software, setup of hardware and conversion of data from Advanced CIS system to Harris NorthStar Version 5.219 was completed in 2007.

Capital Costs:

Acct # & Description	Amount
#1925 – Computer Software	$141,853
#1915 – Computer Hardware	$ 171
Total Project Cost – 2007	$142,024

Start Date: October/November, 2006

In-Service Date: May, 2007

Project Description: #2007-02 - Queen Street Rebuild – Gloucester Street to Yonge St

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. The existing conductor wire is undersized for present load demands.

Scope: 26 poles will be replaced from Gloucester Street to Yonge Street. The existing 1/0 ACSR conductors will be upgraded to 336MCM A1. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equip	$ 8,722
#1830 – Poles, Towers & Fixtures	$ 42,886
#1835 – Overhead Conductors & Devices	$ 25,766
Total Project Cost	$ 77,374

Start Date: April, 2007

In-Service Date: November, 2007

Project Description: #2007-03 - Tiffin Park 44kv Pole & ABS Replacement

Need: Replacement of poles and an aging air brake switch located off William Street (Tiffin Park) in the Town of Midland. The existing switch is in poor condition from years of adverse weathering effects with some rusting and oxidation.

Scope: Replacement of poles and replacing the 44KV air brake switch will help prevent power outages to Midland's large users and six substations. Also, reconfiguring the present ABS location will eliminate 2 poles.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$57,878
Total Project Cost	$57,878

Start Date: April, 2007

In-Service Date: September, 2007

Project Description: #2007-04 - Scott Street Substation

Need: In 2006 MPUC 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. MPUC's distribution system includes six substations, four of which are over 50 years old. The Scott Street Substation was built in 1959 and is in need of replacement.

Scope: The Scott Street Substation is the first of six substations to be upgraded. The project included:

Transformer Replacement:

The transformer replacement will include the manpower, equipment, transportation and disposal of the existing 3000 Kva transformer, and the installation of the 5000 Kva transformer which is the refurbished Queen Street 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 will be replaced with four Schweitzer protection & breaker control relay.

Additional costs will include:
- Door replacement to provide adequate access to install and remove equipment.
- Removal of three 4 X 10' Schedule s of asbestos.
- Replace asbestos with Durasystem Panels.
- MPUC Switching and feeder installation.
- SCADA Commissioning.
- Installation of stone.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equipment	$679,052
#1830 – Poles, Towers & Fixtures	$ 2,579
#1835 – Overhead Conductors & Devices	$ 7,934
#1845 – Undergrnd Conductors/Devices	$ 1,317
#1855 – Services	$ 855
Total Project Cost	$691,737

Start Date: January, 2007

In-Service Date: December, 2007

Project Description: #2007-05 - Purchase of Bucket Truck

Need: Truck #2 (1995 Ford Single Bucket Truck) is in need of replacement. An independent service mechanic recommends Truck# 2 for immediate replacement. An independent vehicle inspection report, performed in Barrie, reveals a number of repairs would be needed to pass inspection. The maintenance and service incurred with this vehicle over the past few years indicates costly repairs will continue. The vehicle body has considerable surface and undercarriage rusting in several locations. The driver and passenger seat is missing vinyl covering, resulting in the loss of cushioning material for proper driving posture. The Altec service advisor has submitted an inspection report on the hydraulic boom system recommending the system be replaced. The vehicle is currently not equipped with air bags or ABS.

Scope: Purchase Single Bucket Ford F-550

Capital Costs:

Acct # & Description	**Amount**
#1930 – Transportation Equipment	$132,987
Total Project Cost	$132,987

Start Date: January, 2007

In-Service Date: August, 2007

Reconciliation to Gross Capital Assets Table:

Other Projects that did not exceed the materiality level of 1% have been explained in Exhibit 2, Tab 2, Schedule 3 in the USoA Numbers as set out therein. These Projects are as follows:

(Note: Those projects marked “CC” represent contributed capital projects)

1

No.	Project Description	Amount
#2007-06	Computer Hardware & Software	$ 19,293
#2007-07	Building purchases	$ 2,950
#2007-08	Replace a number of poles	$ 5,846
#2007-09	Brandon Substation work	$ 2,100
#2007-10	Bourgeois/Bell Canada Lane U/G Loop	$ 2,454
#2007-11	Supply & Install 44kv Arresters at Scada Connections	$ 23,845
#2007-12	Borsa Lane Loop	$ 5,158
#2007-13	Norman Crescent replace pole transformers	$ 5,513
#2007-14	Bourgeois Lane/Perrins work	$ 7,109
#2007-15	Purchase of plotter	$ 8,089
#2007-16	Purchase of snow blower	$ 2,698
#2007-17	Tool purchases	$ 29,392
#2007-18	Implements Shelter – Quanset hut - Expansion	$ 30,694
#2007-19	Meters	$ 12,573
#2007-20	Transformer Refurbishment	$ 7,106
#2007-21	Steel Pallet Shelving	$ 1,035
#2007-22	Flag Pole installation	$ 3,580
#2007-23	New Connections	$ 11,277
#2007-24	Wholesale Metering Point	$ 7,938
#2007-25	William Street work	$ 3,816
#2007-26	Scada purchases	$ 1,618
#2007-27	Dorion Substation – ground grid	$ 24,394
#2007-28	Red Carpet Inn	$ 4,277
#2007-29	Stock Transformers	$ 41,505
#2007-30	Adjustment to cost base of 2006 purchase of truck	$ 19,000
#2007-31	New pole construction – Huron Park, Super 8 & Bay Port Marina	$ 21,329
#2007-32	New pole construction – miscellaneous jobs	$ 3,968
#2007-33	New Services – Aberdeen, HPP, misc	$ 1,645
#2007-34	New Services - CC	$ 6,909
#2007-35	Prospect Blvd. install poles – CC	$ 7,377

No.	Project Description	Amount
#2007-36	Whitney Crescent transformer- CC	$ 4,912
#2007-37	Overhead Service at Torza Top- CC	$ 3,156
#2007-38	Pole installation at 716 Ontario – CC	$ 3,848
#2007-39	New Service 484 Dominion Avenue- CC	$ 6,333
#2007-40	Installation of poles – Easy Street- CC	$ 1,308
#2007-41	Tiffin Plaza transformer job- CC	$ 35,844
#2007-42	Blockbuster transformer job- CC	$ 27,641
#2007-43	Pillsbury Drive – extend primary cable- CC	$ 17,304
#2007-44	General Mills – relocate 44kV- CC	$ 17,531
#2007-45	Super 8 Motel – transformer job- CC	$ 40,533
#2007-46	Bayview School – transformer job- CC	$ 26,526
#2007-47	Noack – relocate primary feed & transformer bank- CC	$ 12,342
#2007-48	Huron Park – primary 3 phase pole riser installation- CC	$ 8,688
#2007-49	343 Midland Avenue – transformer job- CC	$ 9,589
#2007-50	Little Lake Park – pole installation- CC	$ 28,591
	TOTAL Variance Less than 1%	$ 568,634
	TOTAL Variance Greater than 1%	$1,102,000
	TOTAL ADDITIONS 2007	$1,670,634
	Less: Contributed Capital	-$ 218,797
	Net 2007 Additions – per Gross Capital Assets Table	**$1,451,837**

2008 BRIDGE YEAR

Total capital additions for the 2008 year are budgeted at $2,550,453. Those projects exceeding the materiality threshold of $51,683 are as follows:

No.	Project Description	Amount
#2008-01	Brandon Street Substation Upgrade	$1,316,000
#2008-02	Montreal Street Pole Line	$ 105,100
#2008-03	George Street – 3-Phase Bank	$ 58,500
#2008-04	Norman Crescent – Pole Transformer Replacement	$ 73,000
#2008-05	Scott Street Pole Line	$ 76,000
#2008-06	Development Contributions – Economic Evaluations	$ 400,000
#2008-07	Contributed Capital – customer contributions	$ 273,500
	TOTAL PROJECTS EXCEEDING MATERIALITY	**$2,302,100**

Project Description: #2008-01 - Brandon Street Substation Upgrade

Need: In 2006 MPUC completed a substation study that provided an analysis of existing infrastructure and a plan for the replacement taking into consideration future potential growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old. The Brandon Street Substation was built in 1956 and is in need of replacement. This substation upgrade is required to enable MPUC to serve customers without putting safety and reliability at risk. If substation upgrades are delayed, MPUC will be faced with multiple infrastructure replacements at the same time, or in emergency situations which would increase costs due to the nature of the emergency.

Scope: The Brandon Street substation is the second substation to be upgraded. The upgrade to the substation includes:

Engineering Studies:

Includes co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for ESA inspections and a set of ESA approved electric drawings.

Ground Grid Construction:
The existing ground grid, which provides personnel safety, must be upgraded as it does not conform to the Ontario Electrical Safety Code.

Lightning Arrestors:
A set of three arrestors will be supplied and installed.

Transformer Removal and Installation:
Includes the cost to provide manpower, supply of equipment, transportation and removal of the existing three transformers and installation of one new transformer.

Secondary Switchgear Replacement:
This part of the upgrade includes the supply and installation of three 5 Kv-1200 Amp breaker cells, supply and installation of one 2000 amp main breaker.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equip	$1,119,900
#1830 – Poles, Towers & Fixtures	$ 2,000
#1845 – Undergrnd Conductors/Devices	$ 4,000
#1850 – Line Transformers	$ 190,100
Total Project Cost	**$1,316,000**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-02 - Montreal Street Pole Line
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 has

contributed to the deterioration of the poles. This pole line project is needed to enable MPUC to serve customers without putting safety and reliability as risk.

Scope: To replace 16 poles on Montreal Street from Fourth Street to Eighth Street. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. Conductor work will also include the transfer of existing wire from old poles to new poles. Services will be relocated until the new pole line is constructed. Existing transformers will be upgraded and if required a re-balance of the electrical load will be undertaken within the scope of this project.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 60,000
#1835 – Overhead Conductors & Devices	$ 31,000
#1850 – Line Transformers	$ 8,000
#1855 – Services	$ 6,100
Total Project Cost	**$105,100**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-03 - George Street – 3-Phase Bank

Need: Capital funds are required to resolve an ESA order to repair, considered a public safety hazard. The Elcan transformer site is located on George Street. MPUC Operations Department met with Elcan Representatives and discussed an appropriate remedy to this safety issue.

Scope: The project involves the removal of six overhead transformers located within a fenced compound on a concrete pad. In addition a wooden H-frame structure is rotting wood and no grounding can be found on the fenced enclosure. The project involves the removal of six overhead transformers (3x75Kva 4160Y/2400 120/208v and 3 X 100Kva 4160D/2400 347/600v) and "H" frame structure. M.P.U.C. proposes to install 2 x three phase overhead transformer banks (3x75Kva 4160Y/2400 120/208v and 3 X 100Kva 4160D/2400 600v). In addition, four 45' wooden utility poles, steel cross-arms, insulators, brackets, 1/0 stranded copper conductor, arresters, switches, grounding, u-guards, conduit and associated hardware will be installed.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$28,500
#1835 – Overhead Conductors & Devices	$ 5,000
#1850 – Line Transformers	$25,000
Total Project Cost	**$58,500**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-04 - Norman Crescent – Pole Transformer Replacement

Need: Pole transformers pose undue safety risks due to the close proximity of primary and secondary cable in a confined space. Maintenance or emergency service work becomes quite restrictive. Cramming secondary and primary wires in a confined space within a transformer pole poses an undo electrical hazard and hence a safety risk for technicians. Services will be relocated until the new pole line is constructed. This project was originally scheduled to begin in 2007, however the discovery of sub-standard buried primary cable (5Kv) necessitated the entire project be re-estimated and planned for 2008. In the event of a catastrophic failure of one of the pole transformers, power restoration would be very lengthy.

Scope: Capital funds are required to replace 4 pole transformers on Norman Crescent.

Capital Costs:

Acct # & Description	Amount
#1845 – Underground Conductors/Devices	$34,000
#1850 – Line Transformers	$15,000
#1855 – Services	$24,000
Total Project Cost	**$73,000**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-05 - Scott Street Pole Line

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 has contributed to the deterioration of the poles. This pole line project is needed to enable MPUC to serve customers without putting safety and reliability as risk.

Scope: Capital funds are required to replace 13 poles beginning at the Scott St. Sub Station and ending at William St. The 4.16kV distribution circuit will be upgraded from 1/0 to 336 mcm conductor. Conductor work will also include the transfer of the 44 kV feeder from the old poles to the new poles. In conjunction with pole replacements, new cross arms, insulators, guying, grounding and anchoring will be placed. Existing transformers will be upgraded and if required a rebalance of the electrical load will be undertaken within the scope of this project. Existing services will be relocated until the new pole line is constructed.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$45,000
#1835 – Overhead Conductors & Devices	$20,000
#1850 – Line Transformers	$ 5,000
#1855 – Services	$ 6,000
Total Project Cost	**$76,000**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-06 - Development Contributions – Economic Evaluations

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, which is expected in 2008, it is estimated MPUC will pay a transfer price of $400,000 for the assets installed by the developer.

Scope: Mundy's Harbour, Bayport Marina, Riverwalk Greens and the Bayport Pole Line Re-alignment are developments that will see development charges paid in 2008.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 40,000
#1835 – Overhead Conductors & Devices	$ 20,000
#1845 – Undergrnd Conductors/Devices	$ 250,000
#1850 – Line Transformers	$ 60,000
#1855 – Services	$ 30,000
Total Project Cost	**$ 400,000**

Start Date: 2008

In-Service Date: 2008

Project Description: #2008-07 - Capital Contributions – Customer Contributions

Need: MPUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. MPUC 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. In 2007, MPUC had capital contributions of approximately $258,000. The assets were debited depending on the type of work performed and the offsetting credit was posted to account #1995. In 2008 and 2009, MPUC expects to have $273,500 in capital contributions, split between various USoA APH accounts. Based on 2007 levels of contributions, the 2008 contributions are projected to fall into account numbers 1830, 1835, 1845, 1850, and 1855, as follows:

Scope: Projects will be designated by customers. Once MPUC 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	$ 45,040
#1835 – Overhead Conductors & Devices	$ 42,460
#1845 – Undergrnd Conductors/Devices	$ 68,280
#1850 – Line Transformers	$ 83,140
#1855 – Services	$ 34,580
Total Project Cost	**$273,500**

Start Date: 2008

In-Service Date: 2008

Reconciliation to Gross Capital Assets Table:

Other Projects that did not exceed the materiality level of 1% have been explained in Exhibit 2, Tab 2, Schedule 3 in the USoA Numbers as set out therein. These Projects are as follows:

No.	Project Description	Amount
#2008-08	Computer Hardware and Software	$ 27,213
#2008-09	Building purchases	$ 23,200
#2008-10	559 King Street transformer	$ 20,100
#2008-11	334 King Street transformer	$ 40,200
#2008-12	Replace number of poles	$ 12,400
#2008-13	Air Break Switch Replacement Program	$ 34,000
#2008-14	Fault Current Indicator Installation Program	$ 13,000
#2008-15	Taylor's Field Power Line Easement	$ 7,500
#2008-16	Bourgeois Lane Padmount transformer	$ 5,000

No.	Project Description	Amount
#2008-17	44kv arrestors at Scada connections	$ 8,000
#2008-18	845 King Street transformer	$ 30,900
#2008-19	Borsa Lane – Enhancement	$ 31,700
#2008-20	Miscellaneous services – engineering	$ 26,000
#2008-21	AutoCad/Dromey upgrades	$ 13,440
#2008-22	Tools and Test Equipment	$ 33,200
#2008-23	Meters	$ 8,100
#2008-24	Refurbishment of Transformers	$ 48,600
#2008-25	Engineering – 4th Street Substation	$ 50,000
#2008-26	Mini-van purchase	$ 24,800
#2008-27	Outdoor storage cage for propane	$ 3,400
#2008-28	Scada – 3 RTUs	$ 8,700
#2008-29	4 Pole Trailer	$ 15,100
	TOTAL Variance Less than 1%	$ 484,553
	TOTAL Variance Greater than 1%	$2,302,100
	TOTAL ADDITIONS 2008	$2,786,653
	Contributed Capital – net	-$ 236,200
	Net 2008 Additions – per Gross Capital Assets Table	**$2,550,453**

2009 TEST YEAR

Total net capital additions for the 2009 year are budgeted at $2,746,840. Those Projects exceeding the materiality threshold of $51,683 are as follows:

No.	Project Description	Amount
#2009-01	Bourgeois Lane – Replace Transformer Kiosk	$ 53,100
#2009-02	Development Contributions – Economic Evaluation	$ 400,000
#2009-03	Fourth Street Substation Upgrade – Enhancement	$1,234,800
#2009-04	Yonge Street Pole Line – Enhancement	$ 128,200
#2009-05	Hugel Avenue Pole Line – Enhancement	$ 105,200
#2009-06	Sunnyside Pole Line – Expansion	$ 138,800
#2009-07	Purchase of Bucket Truck & Metering Van	$ 335,000

No.	Project Description	Amount
#2009-08	Scada Software Upgrade	$ 100,000
#2009-09	Contributed Capital – Customer Contributions	$ 273,500
	TOTAL PROJECTS EXCEEDING MATERIALITY	**$2,768,600**

Project Description: # 2009-01 - Bourgeois Lane – Replace Transformer Kiosk

Need: Completion of this project will provide MPUC with a back feed source enabling line crews to power customers from alternate circuits during planned (i.e. regular maintenance of equipment) and unplanned outages (i.e. lightening strikes, fallen trees, vehicle mishaps and so on..). Furthermore, the completion of this 3 - Phase looped circuit will provide MPUC with an opportunity to balance the existing loads, improve over-all system efficiency and remove a potential safety hazard. As noted in the 2008 section, engineering funds in the amount of $5,000 were budgeted in 2008 for a engineered solution to this issue.

Scope: To complete a 3 - Phase loop of the existing distribution circuit feeding Bourgeois Lane, south of Dominion Avenue. The project involves the removal of three overhead transformers temporarily located in a pad-mount cabinet and the installation of one, 3 – Phase, 300 KVA Transformer. In addition, a 50' wooden utility pole and three, 100 KVA Pole-mount Transformers will be installed on Midland Avenue.

Capital Costs:

Acct # & Description	Amount
#1845 – Undergrnd Conductors/Devices	$ 4,100
#1850 – Line Transformers	$ 29,000
#1855 – Services	$ 20,000
Total Project Cost	**$ 53,100**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-02 - Development Contributions – Economic Evaluations

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, which is expected in 2008, it is estimated MPUC will pay a transfer price of $400,000 for the assets installed by the developer.

Scope: Christian Midprop, Georgian Landing and Galloway Lands are developments that MPUC believes will require development charges to be paid in 2009.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 40,000
#1835 – Overhead Conductors & Devices	$ 20,000
#1845 – Underground Conductors/Devices	$ 250,000
#1850 – Line Transformers	$ 60,000
#1855 – Services	$ 30,000
Total Project Cost	**$ 400,000**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-03 - Fourth Street Substation Upgrade

Need: In 2006 MPUC completed a substation study that provided an analysis of existing infrastructure and a plan for the replacement taking into consideration future growth in our distribution territory. MPUC's distribution system includes six substations, four of which are over 50 years old. The Fourth Street substation was built in 1954 and is in need of replacement due its age. The substation is currently located below the flood plain and will be required to be moved to an alternate location. . This substation upgrade is required to enable MPUC to serve customers without putting safety and reliability at risk. If substation upgrades are delayed, MPUC will be faced with multiple infrastructure replacements at the same time, or in emergency situations which would increase costs due to the nature of the emergency.

Scope: The Fourth Street substation is the third substation to be upgraded.

The estimate to upgrade the Fourth Street substation includes:

Engineering Studies
Includes co-ordination study, short circuit analysis, ground grid calculation and device analysis. The study will also account for ESA inspections and a set of ESA approved electric drawings.

Ground Grid Construction:
The existing ground grid, which provides personnel safety, must be upgraded as it does not conform to the Ontario Electrical Safety Code.

Tower Components:
This estimate includes the supply and installation of one set of three arrestors, one gang-operated load break switch, and single phase fuse assemblies

Transformer Removal and Installation:
Includes the cost to provide manpower, supply of equipment, transportation and removal of the existing three transformers and installation of one new transformer.

Secondary Switchgear Replacement:
This part of the upgrade includes the supply and installation of four 5 Kv-1200 Amp breaker cells, supply and installation of one 2000 amp main breaker.

Capital Costs:

Acct # & Description	Amount
#1820 – Distribution Stn Equip	$1,045,800
#1830 – Poles, Towers & Fixtures	$ 5,500
#1845 – Undergrnd Conductors/Devices	$ 3,500
#1850 – Line Transformers	$ 180,000
Total Project Cost	**$1,234,800**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-04 - Yonge Street Pole Line

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 MPUC 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. Conductor work will entail transfer of existing conductors to new poles. Existing services will be transferred from the old 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: Capital funds are required to replace 54 poles from County Road 93 to King St.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 88,700
#1835 – Overhead Conductors & Devices	$ 26,000
#1850 – Line Transformers	$ 6,000
#1855 – Services	$ 7,500
Total Project Cost	**$128,200**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-05 - Hugel Avenue Pole Line

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 MPUC 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: Capital funds are required to replace 30 poles from County Road 93 to Eighth St.

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$ 74,000
#1835 – Overhead Conductors & Devices	$ 21,000
#1850 – Line Transformers	$ 4,200
#1855 – Services	$ 6,000
Total Project Cost	**$105,200**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-06 - Sunnyside Pole Line

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 has contributed to their deterioration. This pole line project is required to enable MPUC 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. Upgrade of this pole line is also required to provide the necessary capacity for future demand.

Scope: Capital funds are required to replace poles in Sunnyside

Capital Costs:

Acct # & Description	Amount
#1830 – Poles, Towers & Fixtures	$92,500
#1835 – Overhead Conductors & Devices	$ 46,300
Total Project Cost	**$138,800**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-07 - Purchase of Bucket Truck; Purchase of Metering Van

Need: Vehicle Replacements: It is MPUC's policy to replace aging vehicles in an even fashion avoiding sudden increases in capital acquisitions. MPUC'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 the past few 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. MPUC 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 metering 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. MPUC'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	$335,000
Total Project Cost	**$335,000**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-08 - SCADA Software Upgrade

Need: MPUC'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 which is similar to UNIX. Over the past several years, the software engineers added a SCADA System which operates on a Windows Platform. MPUC's plan is to upgrade our current VMS based SCADA system to the Windows system. This change will not only facilitate the export of real time and historical data but will simplify operational controls.

Scope: Purchase SCADA software

Capital Costs:

Acct # & Description	Amount
#1980 – System Supervisory Equip.	$100,000
Total Project Cost	**$100,000**

Start Date: 2009

In-Service Date: 2009

Project Description: #2009-09 - Capital Contributions – Customer Contributions

Need: MPUC receives cash contributions from customers as capital contributions. These contributions are included in account #1995 in accordance with the APH. MPUC 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. In 2007, MPUC had capital contributions of approximately $258,000. The assets were debited depending on the type of work performed and the offsetting credit was posted to account #1995. In 2008 and 2009, MPUC expects to have $273,500 in capital contributions, split between various USoA APH accounts. Based on 2007 levels of contributions, the 2009 contributions are projected to fall into account numbers 1830, 1835, 1845, 1850, and 1855, as follows:

2007 Contributed Capital		
Acct #	**Amount**	**Percentage**
1830	42,554.39	16.47%
1835	40,112.93	15.52%
1845	64,519.40	24.97%
1850	78,561.30	30.40%
1855	32,683.16	12.65%
	258,431.18	1.00

2008/2009 Contributed Capital		
Acct #	**Amount**	**Percentage**
1830	45,040	16.47%
1835	42,460	15.52%
1845	68,280	24.97%
1850	83,140	30.40%
1855	34,580	12.65%
	273,500	1.00

Scope: Projects will be designated by customers. Once MPUC 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	$ 45,040
#1835 – Overhead Conductors & Devices	$ 42,460
#1845 – Undergrnd Conductors/Devices	$ 68,280
#1850 – Line Transformers	$ 83,140
#1855 – Services	$ 34,580
Total Project Cost - #1995	**$273,500**

Start Date: 2009

In-Service Date: 2009

Reconciliation to Gross Capital Assets Table:

Other Projects that did not exceed the materiality level of 1% have been explained in Exhibit 2, Tab 2, Schedule 3 in the USoA Numbers as set out therein. These Projects are as follows:

No.	Project Description	Amount
#2009-10	Computer Hardware & Software	$ 39,040
#2009-11	Building purchases	$ 35,000
#2009-12	Replace a number of poles – Enhancement	$ 11,300
#2009-13	Air Break Switch Program – Enhancement	$ 31,200
#2009-14	Current Fault Indicators – Enhancement	$ 11,900
#2009-15	Metering Equipment	$ 10,000
#2009-16	Transformer Refurbishment	$ 15,000
#2009-17	Tools and Test Equipment	$ 10,000
#2009-18	Kabar Replacement	$ 40,000

No.	Project Description	Amount
	TOTAL Variance Less than 1%	$ 203,440
	TOTAL Variance Greater than 1%	$2,768,600
	TOTAL ADDITIONS 2009	$2,972,040
	Contributed Capital – net	$ -225,200
	Net 2009 Additions – per Gross Capital Assets Table	**$2,746,840**

Substation Study

A copy of the Substation Study is attached on the following pages

RONDAR INC.

MIDLAND PUC
SUBSTATION EVALUATION

Prepared For: Wayne Dupuis, C.E.T.

Prepared By: Dan Brown, A.Sc.T.

Date: September 25, 2006

September 25, 2006

Midland PUC
16984 Highway 12
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis, C.Tech.**

Subject: **Distribution Substation Evaluations**
Our Reference No. C1753

Dear Sir,

We are enclosing the results of the assessment of Midland PUC's six (6) distribution substations. The inspections were completed on August 2, 3, 17 and 18, 2006.

The results indicate that the order of priority to complete the repairs is as follows. We recommend that the work at Scott Street and Brandon Street be completed as soon as possible.

1) Scott Street Substation
2) Brandon Street Substation
3) Fourth Street Substation
4) Dorion Street Substation
5) Montreal Street Substation
6) Queen Street Substation

Before construction commences, we also recommend that the following engineering studies be completed to support equipment selection: protection co-ordination study, short circuit analysis, ground grid study, and equipment evaluation study.

We trust that the contents, comments and recommendations of the assessment meet your satisfaction. If any further information or explanations are required, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown, A.Sc.T.
Technical Service Representative

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RONDAR INC.

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RONDAR INC.

Section 1

SCOTT STREET SUBSTATION

1.1 System Overview

The Scott Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M4' circuit. It is connected to the gang-operated 46kV air break switch designated 'C37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and one (1) three phase, 3 MVA, power transformer. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via a metal enclosed bus duct. The indoor switchgear has four (4) cells that contain three (3) oil-filled circuit breakers, metering device, protection and control equipment.

1.2 Ground Grid and Bonding Assessment

The ground grid consists of five (5) copper ground rods, ½ inch in diameter and is interconnected utilizing 2/0 AWG bare copper forming a continuous loop around the substation equipment. The thermal (CAD) welded connections between the 2/0 AWG bare copper loop, ground rods and bonding conductors are in good condition and correct for a direct burial installation. The exterior fence enclosure is bonded together via a 2/0 AWG bare copper loop connected to six (6) ¾ inch, ten foot copper rods. This ground loop was found not physically connected to the substation ground grid and is located within the perimeter of the metallic fence enclosure.

The bonding of the equipment to the substation ground grid was found to be as follows:
A connection to each footing of the tower structure; one (1) connection to the transformer tank; one (1) connection to the indoor switchgear, one (1) connection to the lightning arresters and one (1) connection to the gang-operated high voltage switch but not the switch handle.

Based on our assessment, we recommend the following deficiencies be corrected:

1) As per the *Ontario Electrical Safety Code 36-310(2)(a)(b)* and *Table 52*, and in the interest of personnel safety, we recommend installing a metallic gradient control mat to ensure the touch voltage is minimized to a tolerable level during switching operations. The gradient control mat maximizes the safety of the operator(s) during switching operations.
2) As per the *Ontario Electrical Safety Code 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connect this loop directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
3) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and tank for the power transformer. The second connection is a redundant bonding connection to ensure the tank remains bonded to the ground grid if an internal fault occurs.

4) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the indoor switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.
5) As per the *Ontario Electrical Safety Code 36-304(5)*, *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves) and installing 12 inches of ¾ crushed stone to provide a dielectric layer that minimizes the touch and step potential.
6) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
7) As per the *Ontario Electrical Safety Code 36-312(4)*, the ground conductor should be woven throughout the fence fabric in at least two (2) places. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two places per conductor.
8) The steel removable section of the substation brick wall is covered with asbestos. Due to the health hazard associated with asbestos as it becomes brittle, we recommend that the asbestos be labelled as a health hazard and removed prior to any construction work being completed.

1.3 Tower Structure and Components Assessment

Galvanized Tower Structure

The galvanizing of the steel and hardware on the tower structure is presently in good condition with very slight rust development. The visual inspection of the two (2) tower concrete footings and steel bases concluded that there is no significant deterioration.

The current carrying bus work is ¾ inch copper IPS and supported with polymer station post insulators. The insulation ratings of the insulators and clearances between the primary buses and grounded surfaces are suitable for the voltage rating.

The tower structure and primary bus work are suitable for continued service.

No further action is required.

Primary 44kV Air Break Switch

The primary air break switch is rated for 46kV and 600 amperes. The ratings of this switch are satisfactory for the application; however, this product is no longer supported by the manufacturer, making replacement parts unavailable. The design of the switch is as an air break switch and does not have load breaking capabilities. The necessary 'kirk' key system is in place and provides the necessary sequence to ensure the switch is not operated under load. Our preventative maintenance reports indicate that the current carrying components are in satisfactory condition and have undergone slight deterioration caused by the outdoor environment.

Based on the unavailability of parts and manufacturer support, we recommend upgrading the air break switch to an S&C, Alduti Rupter load break switch rated for a maximum voltage of 48.6kV, a continuous current of 600A and interrupt capacity of 40000 amperes.

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by S&C Electric and replacement fuse links are available.

The short circuit, voltage and over current ratings the fuse units provide is excellent equipment protection and suitable for this application.

No further action is required.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are a porcelain gap type constructed arrester and manufactured by EMP Electric. The gap type arrester is prone to failure due to moisture ingress into the semi-conductive material within the unit. The moisture reduces the resistance of the components within the arresters directly affecting the kV and maximum continuous operating voltage (M.C.O.V.) rating of the device and the reliability of surge protection.

We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV. This type of arrester will provide adequate protection of the insulation of the power transformer by dissipating damaging system over voltages and surges.

1.4 Transformer Assessment

The Ferranti-Packard power transformer, s/n 1-1028, has a capacity of 3 MVA and is configured with a primary 44000 volt, delta connected, primary winding and a secondary 4160 volt, wye configured, winding. The secondary neutral bushing is directly connected to the substation ground grid and is commonly referred to as a “solidly grounded Wye system”. The Ferranti-Packard transformer was constructed in 1959 and has provided service for approximately 47 years.

The primary 44kV porcelain bushings are generally in fair condition with damage to the centre, H2 bushing caused by a flash as result of animal contact. As stated in our preventative maintenance reports, this damage has not affected the insulation properties of the bushing; however, will require replacement in the future.

The insulation resistance of each winding to ground and winding to winding has remained relatively constant since 2000.

The results of the oil analysis indicate that the levels of Furfuraldehyde (Furan) have steadily increased since October 1999 with levels expected to continue increasing. Furans are produced when the paper insulation used to insulate each winding has been damaged by elevated heat levels in the insulation. In October 2004, the actual furan level in this transformer was 567 parts per billion (ppb) indicating that the paper insulation has undergone significant deterioration due to heat stress. A transformer that has furan levels equal to or greater than 500 ppb can no longer be considered reliable, therefore, Rondar Inc. recommends that a provision for replacement be developed as soon as possible. The furan concentration is assessed as follows:

Rondar Inc. Furan Assessment	
< 100 ppb	Good Condition
250 ppb	Fair to Poor Condition
> 500 ppb	Undergone Severe Deterioration
*ppb = parts per billion	

Based on the results of the oil analysis trending, preventative maintenance reports and our assessment, we recommend replacing and increasing the capacity of this transformer. The degradation of the paper insulation confirms that this transformer cannot be considered reliable; furthermore, refer to our comments and recommendations pertaining to the indoor switchgear.

1.5 Enclosure Assessment

The indoor switchgear is mounted in a residential style building that is suitable for this application and appears to be in satisfactory condition. The temperature within the building was found to be warm. We recommend installing a climate control system to regulate the inside temperature which would benefit the life span of any electronic devices, especially the DC battery bank.

We request that a company specializing in structural assessments be contacted if further details regarding structural condition of the building are required.

1.6 Switchgear Assessment

Switchgear Enclosure

The General Electric Switchgear is a Metal Clad type enclosure. Based on the manufacturing date of the transformer and available drawings, it is approximately 47 years old. The switchgear contains the following components:

- One set of three (3) metering potential transformers.
- One set of three (3) metering current transformers.

- Revenue metering equipment.
- Three (3) oil-filled circuit breakers with DC controls.
- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers.
- Two (2) phase over current relays per breaker.
- One (1) neutral over current relay per breaker.

The main bus work of the switchgear is a copper tubular bus bar that is horizontally mounted in the top front area behind covers. The bus bars are insulated throughout and isolated from each cell by a metal plate. Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle and can cause the insulation to crack or break during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment. As above, the components have reached or are near the end of their service life and reliability is questionable. The repair time necessary to locate, investigate and retrofit new control equipment into this switchgear will be time consuming, expensive and significant downtime would be required.

Based on the age of the switchgear, insulation, components and wiring, we recommend replacing the switchgear as soon as possible.

5kV Oil Circuit Breakers (OCB)

The OCB's are breakers that use insulating oil as a dielectric medium to insulate the 'live' parts from metal surfaces and minimize the electric arc during opening/closing operations. The breaker consists of six (6) bushings, two (2) sets of contacts per phase, one (1) closing coil (cc), one (1) tripping coil (tc) and necessary operating mechanisms to perform opening and closing functions. The breakers can be either opened or closed manually or electrically. We consider the age of the oil-filled circuit breakers to be the same vintage as the switchgear and transformer which indicates they were purchased near the end of their production by General Electric in the early 1950's; they are 47 years old.

The main contacts, current carrying components and most of the operating mechanism are submersed in 15 U.S. gallons of oil and can only be visually inspected by removing the tank. The internal components have not been inspected since 1999 and at that time damage to the contact surfaces was noted. Based on the age of the device, the spring tensions and excessive wearing on various shafts, bearings and latches can contribute to trip free and mechanical nuisance problems that affect the reliability of these breakers. The availability of replacement parts is limited and often do not work without further modifications during installation.

Based on the age of the breakers, high maintenance costs and decreasing reliability, we recommend that the breakers and switchgear be replaced.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The existing configuration of the protection devices provides over current protection on the 'A' and 'C' phases along with residual ground fault protection. This protection design was adequate when the system was designed, however, does not provide complete protection for the components of the distribution network supplied by the phase 'B' circuit.

This deficiency can be corrected by adding an additional induction disc relay or upgrading the relay protection to a modern microprocessor based device. A modern microprocessor based device can provide significant advantages to Midland PUC including personnel safety and system reliability through the following:

- Fault Location:
  An event recorder can provide information pertaining to the system prior to a breaker operation and general fault location.
- Remote Monitoring:
  This requires a supervisory-type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VA, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, etc.

Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear complete with vacuum air circuit breakers and a remote relay panel. We further recommend installing a transformer and switchgear package to simplify the installation.

Battery Bank

The battery bank appears to be within five (5) years old and the general condition of the charger, liquid levels and terminal connections are satisfactory. If replacement of the indoor switchgear commences, the output voltage of the existing bank, 48 VDC would require upgrading to match the required DC controls of the new equipment.

1.7 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below:

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel in proximity to the switchgear from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the pressure, gases away from the operator and areas where personnel generally position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the fault current; however, the configuration of the relay protection devices does not include ground fault protection and relies solely on the over current elements to clear a fault. We recommend upgrading the relay protection to a three (3) phase and ground fault over current protection scheme to provide optimum equipment and personnel protection.

The oil filled circuit breakers utilize a vertical lift type insertion system that requires the door to be open and operator to be directly in front of the breaker in the cell. This inherently places the operator in the most dangerous position if the insertion system or an electrical component(s) fails during its operation or racking onto the live 5kV bus. Furthermore, to manually operate the breaker places the operator in the same position. *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and electrically operated only with the door closed.

1.8 Conclusion

Based on the results of our assessment and preventative maintenance reports, the condition of the primary fuse assembly is suitable for continued service. We recommend upgrading the primary lightning arresters to increase the surge protection for the downstream devices. Due to age, availability of replacement parts, maintenance costs and low reliability, we recommend replacing and upgrading the primary air break switch, the main transformer and switchgear assembly. Modernizing the substation to meet current Ontario Electrical Safety Code, National Fire Protection and IEEE Standards would increase system reliability and ensure safety to both utility personnel and the general public.

RONDAR INC.

Midland PUC
Substation Evaluation Project
Job No. C1753

The following is a summary of our recommendations;

1) As per the *Ontario Electrical Safety Code 36-310(2)(a)(b)* and *Table 52*, and in the interest of personnel safety, we recommend installing a metallic gradient control mat to ensure the touch voltage is minimized to a tolerable level during switching operations. The gradient control mat maximizes the safety of the operator(s) during switching operations.
2) As per the *Ontario Electrical Safety Code 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connect this loop directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
3) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and tank for the power transformer. The second connection is a redundant bonding connection to ensure the tank remains bonded to the ground grid if an internal fault occurs.
4) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the indoor switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.
5) As per the *Ontario Electrical Safety Code 36-304(5)*, *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves) and installing 12 inches of ¾ crushed stone to provide a dielectric layer that minimizes the touch and step potential.
6) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
7) As per the *Ontario Electrical Safety Code 36-312(4)*, the ground conductor should be woven throughout the fence fabric in at least two (2) places. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two places per conductor.
8) The steel removable section of the substation brick wall is covered with asbestos. Due to the health hazard associated with asbestos as it becomes brittle, we recommend that the asbestos be labelled as a health hazard and removed prior to any construction work being completed.
9) We recommend upgrading the air break switch to a S&C, Alduti Rupter load break switch rated for a maximum voltage of 48.6kV, a continuous current of 600A and interrupt capacity of 40000 amperes.

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10) We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV. This type of arrester will provide adequate protection of the insulation of the power transformer by dissipating damaging system over voltages and surges.

11) Based on the results of the oil analysis trending, preventative maintenance reports and our assessment, we recommend replacing and increasing the capacity of this transformer. The degradation of the paper insulation confirms that this transformer can not be considered reliable; furthermore, refer to our comments and recommendations pertaining to the indoor switchgear.

12) Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear complete with vacuum air circuit breakers and a remote relay panel. We further recommend installing a transformer and switchgear package to simplify the installation.

13) We recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a stand alone panel adjacent to the switchgear panel. This will allow personnel to view the relay information without standing directly in front of the switchgear.

14) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and electrically operated only with the door closed.

Section 2

DORION STREET SUBSTATION

2.1 System Overview

The Dorion Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M2' circuit. It is connected to the gang-operated 46kV air break switch designated 'D37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and one (1) three phase, 5 MVA, power transformer. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via a copper IPC bus. The indoor switchgear has four (4) cells that contain two (2) oil-filled and one (1) air blast circuit breaker, metering device, protection and control equipment.

2.2 Ground Grid and Bonding Assessment

The original substation ground grid does not exist. The switchgear and transformer are bonded to the system neutral which is providing a ground reference and a current return path. The fate of the original ground grid cannot be determined as we were only able to locate remnants west of the spare switchgear.

Based on the results of our assessment, we recommend constructing a new substation ground grid to comply with the requirements outlined in *sections 10 and 36 of the Ontario Electrical Safety Code*. The condition of the ground grid and the bonding to the structures may cause a step and touch potential hazard for personnel during a fault since the ground grid is not consistent throughout the substation and the potential rise exceeds the allowable step and touch voltages outlined in *Table 52 of the Ontario Electrical Safety Code*. This is an item that should be addressed, as soon as possible, to ensure safety to the public and utility personnel.

2.3 Tower Structure and Components Assessment

Galvanized Tower Structure

The tower structure was constructed using galvanized steel and hardware and is presently in fair condition with slight rust development. The visual inspection of the two (2) tower concrete footings and steel bases concluded that there is no significant visual deterioration and therefore suitable for continued use.

The current carrying IPC bus work is supported with polymer and porcelain station post style insulators. The ratings of the insulators and clearances between the primary buses and grounded surfaces are suitable for the voltage rating.

No further action is required.

Primary 44kV Air Break Switch

The primary air break switch is rated for 46kV and 600 amperes. The ratings of this switch are satisfactory for the application; however, this product is no longer supported by the manufacturer, making replacement parts unavailable. The design of the switch is as an air break switch and does not have load breaking capabilities. Our preventative maintenance reports indicate that the current carrying components are in satisfactory condition and have undergone slight deterioration caused by the outdoor environment.

Based on the unavailability of parts and manufacturer support, we recommend upgrading the air break switch to an S&C, Alduti Rupter load break switch rated for a maximum voltage of 48.6kV, a continuous current of 600A and interrupt capacity of 40000 amperes.

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by S&C Electric and replacement fuse links are available.

The short circuit, voltage and over current ratings the fuse units provide is excellent equipment protection and is suitable for this application.

No further action is required.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are of a porcelain gap type constructed arrester and manufactured by CLM Industries. The gap type arrester is prone to failure due to moisture ingress into the semi-conductive material within the unit. The moisture reduces the resistance of the components within the arresters directly affecting the kV and maximum continuous operating voltage (M.C.O.V.) rating of the device. This affects the reliability of surge protection for the electrical equipment downstream from these devices.

We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV.

2.4 Transformer Assessment

The Moloney Electric power transformer, s/n 238691, has a capacity of 5 MVA and is configured with a primary 44000 volt, delta connected, primary winding and a secondary 4160 volt, wye configured winding. The secondary neutral bushing is directly connected to the substation ground grid and is commonly referred to as a "solidly grounded Wye system". The Moloney Electric transformer was constructed in 1967 and has provided service for approximately 39 years.

The primary 44kV porcelain bushings are in fair condition, however; H3 bushing has a large chip in one (1) skirt of the porcelain housing. As stated in our preventative maintenance reports, this damage has not affected the insulation properties of the bushing but the integrity has been damaged and moisture will start to affect the bushing in the future.

The insulation resistance of each winding to ground and winding to winding has remained relatively constant since 2000.

The results of the oil analysis indicate that the levels of Furfuraldehyde (Furan) have slightly increased since November 1999. Furans are produced when the paper insulation used to insulate each winding has been damaged by elevated heat levels in the insulation. In October 2004, the actual furan level in this transformer was 76 parts per billion (ppb) indicating that the paper insulation is in good condition. The dissolved gas-in-oil results indicate that between October 1999 and October 2004, acetylene had been produced but is no longer being produced at this time. Our concern is that it has been produced and the reason for the problem was not repaired. A reoccurrence is probable and because acetylene is produced by an internal arc, this can lead to rapid equipment failure.

Rondar Inc. Furan Assessment	
< 100 ppb	Good Condition
250 ppb	Fair to Poor Condition
> 500 ppb	Undergone Severe Deterioration
*ppb = parts per billion	

Based on the results of the oil analysis and preventative maintenance results, we consider this transformer, s/n 238691 to be suitable for continued service and recommend completing annual oil sampling to monitor the oil properties and dissolved gases. A change in these concentrations would indicate a fault is developing within the transformer and corrective action is required.

2.5 Switchgear and Enclosure Assessment

The enclosure is a prefabricated metal clad building that incorporates the switchgear with three (3) breakers and one (1) metering cell into the overall design.

The paint condition of the exterior has deteriorated, however, is in satisfactory condition.

The three (3) top mounted 5kV bushings that provide the connection between the transformer and the internal bus work are in good condition and free from any mechanical damage.

The ambient temperature within the enclosure was found to be excessive and contributes to insulation deterioration.

We recommend installing a climate control system to benefit the long term reliability of the electrical equipment, especially the DC battery bank.

2.6 Switchgear Assessment

The General Electric Switchgear is a Metal Clad type enclosure and contains the following components:

- One set of three (3) metering potential transformers.
- One set of three (3) metering current transformers.
- Two (2) oil-filled circuit breakers with DC controls.
- One (1) air blast circuit breaker with DC controls.

- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers.
- Two (2) phase over current relays per breaker.
- One (1) neutral over current relay per breaker.

The main bus work of the switchgear is a copper tubular bus bar that is horizontally mounted in the top front area behind covers. The bus bars are insulated throughout and isolated from each cell by a metal plate. Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration since original construction is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle and can cause the insulation to crack or break during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment. As above, the components have reached or are near the end of their service life and reliability is questionable. The repair time necessary to locate, investigate and retrofit in new control equipment into this switchgear will be time consuming, expensive and significant downtime would be required.

5kV Oil Circuit Breakers (OCB)

The OCB's are breakers that use insulating oil as a dielectric medium to insulate the 'live' parts from metal surfaces and minimize the electric arc during opening/closing operations. During each operation of the breaker, carbon is produced and it slowly contaminates the oil, affecting the dielectric properties. This requires the insulating oil to be replaced and increases the annual preventative maintenance costs. There is not a time frame which the oil has to be replaced but is determined by the results of a dielectric oil sample analysis.

The main contacts, current carrying components and most of the operating mechanism are submersed in 15 U.S. gallons of oil and can only be visually inspected by removing the tank. The internal components have not been inspected since 1999 and at that time damage to the contact surfaces was noted. Based on the age of the device, the spring tensions and excessive wearing on various shafts, bearings and latches can contribute to trip free and mechanical nuisance problems that affect the reliability of these breakers. Replacement parts are not available and therefore 'used' parts are the only option. Used parts are difficult to locate for these breakers and often do not work without further modifications.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The existing configuration of the protection devices provides over current protection on the 'A' and 'C' phases along with residual ground fault protection. This protection design was adequate when the system was designed, however, does not provide complete protection for the components of the distribution network supplied by the phase 'B' circuit.

This deficiency can be corrected by adding an additional induction disc relay or upgrading the relay protection to a modern microprocessor based device. A modern microprocessor based device can provide significant advantages to Midland PUC including personnel safety and system reliability through the following:

- Fault Location:
  An event recorder can provide information pertaining to the system prior to the breaker operation, faulted phase, fault type, and general fault location.
- Remote Monitoring:
  This requires a supervisory-type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VAs, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, breaker controls.

Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend replacing the existing switchgear, breakers and relay protection devices. We also recommend installing a residual connected ground fault relay to sense and trip the associated breaker, as soon as possible, to prevent equipment damage and ensure personnel safety.

Battery Bank

The battery bank appears to be within five (5) years old and the general condition of the charger, liquid levels and terminal connections are satisfactory. If replacement of the indoor switchgear commences, the output voltage of the existing bank, 48 VDC, may have to be upgraded to match the required DC controls of the new equipment.

2.7 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below:

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel in proximity to the switchgear from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the gases away from the operator and areas where personnel generally position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the fault current; however, the configuration of the relay protection devices does not include sensing on the phase 'B' circuit and relies on the other phases and neutral protection to sense and clear a fault. We recommend upgrading the relay protection to a three (3) phase and neutral over current protection scheme to provide optimum equipment and personnel protection.

The oil-filled circuit breakers utilize a vertical lift type insertion system that requires the door to be open and the operator to be directly in front of the breaker in the cell. This inherently places the operator in the most dangerous position should the insertion system or an electrical component(s) fail during its operation or racking onto the live 5kV bus. Furthermore, to manually operate the breaker places the operator in the same position. *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on this hazard/risk assessment, we recommend implementing a procedure to eliminate this hazard.

2.8 Conclusion

Based on the results of our assessment and preventative maintenance reports, we recommend installing a new ground grid and replacing the primary switch, lightning arresters, prefabricated switchgear and protection relays. Furthermore, we recommended completing annual oil sampling to closely monitor the condition of the transformer.

The following is a summary of our recommendations made in the report;

1) We recommend constructing a new substation ground grid to comply with the requirements outlined in ***sections 10 and 36 of the Ontario Electrical Safety Code***. The condition of the ground grid and the bonding to the structures may cause a step and touch potential hazard for personnel during a fault since the ground grid is not consistent throughout the substation and the potential rise exceeds the allowable step and touch voltages outlined in *Table 52 of the Ontario Electrical Safety Code*. This is an item that should be addressed, as soon as possible, to ensure safety to the public and utility personnel.
2) Based on the unavailability of parts and manufacturer support, we recommend upgrading the air break switch to an S&C, Alduti Rupter load break switch rated for a maximum voltage of 48.6kV, a continuous current of 600A and interrupt capacity of 40000 amperes.
3) We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV. The new arresters will increase the surge protection.

4) Based on the results of the oil analysis and preventative maintenance results, we consider this transformer, s/n 238691 to be suitable for continued service and recommend completing annual oil sampling to monitor the oil properties and dissolved gases. A change in these concentrations would indicate a fault is developing within the transformer and corrective action is required.
5) We recommend installing a climate control system to benefit the long term reliability of the electrical equipment, especially the DC battery bank.
6) Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend replacing the existing switchgear, breaker and relay protection devices. We also recommend installing a residual connected ground fault relay to sense and trip the associated breaker, as soon as possible, to prevent equipment damage and ensure personnel safety.
7) We recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a remotely mounted panel adjacent to the switchgear panel. This will allow personnel to view the relay information without having to be directly in front of the switchgear and will also provide more sensitive protection.
8) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on this hazard/risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and electrically operated only with the door closed.

Section 3

BRANDON STREET SUBSTATION

3.1 System Overview

The Brandon Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M2' circuit. It is connected to the gang-operated 48.3kV load break switch designated 'G37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and three (3) single phase, 1.667 MVA, power transformers. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via aluminium IPC bus. The indoor switchgear has five (5) cells that contain four (4) oil-filled circuit breakers, metering devices, protection and control equipment.

3.2 Ground Grid and Bonding Assessment

The ground grid consists of two (2) copper ground rods, ½ inch in diameter and interconnected utilizing 2/0 AWG bare copper forming a continuous loop around the substation equipment. The thermal (CAD) welded connections between the 2/0 AWG bare copper loop, ground rods and bonding conductors are in good condition and correct for a direct burial installation.

The bonding of the equipment to the substation ground grid was found to be as follows:
A connection to each footing of the tower structure, one (1) connection to the transformer tank, one (1) connection to the outdoor switchgear, one (1) connection to the lightning arresters and one (1) connection to the gang-operated high voltage switch but not the switch handle.

Based on our assessment, we recommend the following deficiencies be corrected:

1) As per the *Ontario Electrical Safety Code 36-302*, a minimum of four (4) ground rods are required. We recommend installing two (2) additional ground rods and connecting these rods to the existing ground loop.
2) As per the *Ontario Electrical Safety Code 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connecting this loop directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
3) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and tank of each power transformer. The second connection is a redundant bonding connection to ensure the tank remains bonded to the ground grid if an internal fault occurs.
4) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.

5) As per the *Ontario Electrical Safety Code 36-304(5)* and *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection is maintained.
6) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and the operating switch handle to ensure the potential difference is minimized.
7) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
8) As per the *Ontario Electrical Safety Code 36-312 and Table 52*, we recommend connecting the fence ground loop to the station ground grid with a minimum of two (2) connections.
9) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52*, the ground conductor should be woven throughout the fence fabric in at least two (2) places. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two places per conductor.

NOTE:
The size of the existing substation is not required for the amount of equipment installed. Additionally, we recommend installing a new fence enclosure around the existing equipment and removing what is not required of the existing fence. This will minimize the costs associated with upgrading the station ground grid and associated grounding and bonding connections.

3.3 Tower Structure and Components Assessment

Aluminium Tower Structure

The condition of the aluminium outdoor tower structure is presently in good condition. The visual inspection of two (2) concrete footings and tower bases concluded there is no significant deterioration.

The current carrying bus work is aluminium IPC and supported with porcelain and polymer station post insulators. The insulation rating and clearances between the primary buses and grounded surfaces are suitable for the voltage rating.

No further action is required.

Primary 44kV Air Break Switch

The primary air break switch is rated 48.3kV, 600A with a basic impulse level of 250kV. The ratings of the switch are satisfactory for this application and the product is supported by the manufacturer making replacement parts readily available.

No further action is required.

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by S&C Electric and replacement fuse links are available.

The short circuit, voltage and over current ratings of the fuse units provide excellent equipment protection and are suitable for this application.

No further action is required.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are a porcelain gap type constructed arrester. The gap type arrester is prone to failure due to moisture ingress into the semi-conductive material within the unit. The moisture reduces the resistance of the components within the arresters directly affecting the kV and maximum continuous operating voltage (M.C.O.V.) rating of the device. This affects the reliability of surge protection for the electrical equipment downstream from these devices.

We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV.

3.4 Transformer Assessment

The Packard Electric three (3) single phase transformers, phase ‘A’:, s/n 213274, phase ‘B’, s/n 213273, phase ‘C’, s/n 213275, and spare, s/n 213272, have a combined capacity of 5 MVA and is configured with a primary winding 44000 volts, delta connected winding and a secondary 4160 volt, wye configured winding. The primary and secondary bus work connections accommodate the delta and wye connections between the single phase transformers. The secondary neutral bushings are bonded together and directly connected to the substations ground grid. This connection is commonly referred to as a “solidly grounded wye system”. The Packard Electric transformers were constructed in 1956.

The primary 44kV porcelain bushings are in fair condition with damage to one (1) 5kV bushing that has been temporarily repaired and will require replacement in the future. Due to the age of the transformers, replacement bushings are difficult to locate.

The results of the oil analysis indicates that the level of Furfuraldehyde (Furan) in each of the single phase transformers, excluding the spare, indicate that the paper insulation has undergone extensive deterioration. Furans are produced when the paper insulation used to insulate each winding has been damaged by elevated temperatures in the insulation. In October 2004, the actual furan levels in the phase ‘A’, ‘B’ and ‘C’ transformers were 1344, 1144 and 1145, respectively, parts per billion (ppb).

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Rondar Inc. Furan Assessment	
< 100 ppb	Good Condition
250 ppb	Fair to Poor Condition
> 500 ppb	Undergone Severe Deterioration
*ppb = parts per billion	

The results of the dissolved gas-in-oil analysis for the phase 'A', s/n 213274, transformer indicate an elevated level of carbon monoxide and dioxide. These gases are produced in conjunction with excessive heating of the paper insulation and support our comments regarding furan levels.

The results of the dissolved gas-in-oil analysis for the phase 'B', s/n 213273, transformer indicate an elevated level of carbon monoxide and dioxide. These gases are produced in conjunction with excessive heating of the paper insulation and support our comments regarding furan levels. Furthermore, hydrogen is starting to be produced and we suspect it involves the deterioration of the paper insulation. Although the fault was not severe in October 2004, corona will continue to deteriorate the insulation and worsen over time. Failure of this unit is imminent.

The results of the dissolved gas-in-oil analysis for the phase 'C', s/n 213275, transformer indicate an elevated level of carbon monoxide and dioxide. These gases are produced in conjunction with excessive heating of the paper insulation and support our comment regarding furan levels.

Based on the trending results from the oil analysis and preventative maintenance reports, we recommend replacing these transformers in one (1) year and consider the three single phase transformers to have a high potential for failure. We also recommend installing a single three (3) phase 8-10 MVA transformer to meet current and future residential and commercial growth.

3.5 Switchgear Assessment (a)

The enclosure is a prefabricated metal clad building that incorporates the switchgear with four (4) breakers and one (1) metering cell into the overall design. We estimate the age of the enclosure to be 45–50 years old.

The exterior paint condition was repainted two (2) years ago and is in satisfactory condition.

The three (3) top mounted 5kV bushings that provide the connection between the transformer and internal bus work are in good condition and free from any mechanical damage.

The ambient temperature within the enclosure was found to be excessive and contributes to insulation deterioration.

We recommend installing a climate control system which would benefit the long-term reliability of the electrical equipment, especially the DC battery bank.

3.6 Switchgear Assessment (b)

The Crompton Parkinson Electrical Switchgear is a Metal Clad type enclosure that is approximately 50+ years old based on the manufacturing date of the transformer. The switchgear contains the following components:

- One set of three (3) metering potential transformers
- One set of three (3) metering current transformers
- Four (4) oil-filled circuit breakers with DC controls
- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers.
- Three (3) phase over current relays per breaker

The main bus work of the switchgear is horizontally mounted in the top rear area behind covers. The bus bars are insulated throughout and isolated from each cell by a metal plate. Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration since original construction is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle and can cause the insulation to crack or break during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment. As above, the components have reached or are near the end of their service life and reliability is questionable. The repair time necessary to locate, investigate and retrofit in new control equipment into this switchgear will be time consuming, expensive and significant downtime would be required.

5kV Oil Circuit Breakers (OCB)

The OCB's are breakers that use insulating oil as a dielectric medium to insulate the 'live' parts from metal surfaces and minimize the electric arc during opening/closing operations. The breaker consists of six (6) bushings, two (2) sets of mechanism operating contacts per phase, one (1) closing coil (cc), one (1) tripping coil (tc) and necessary operating mechanisms to perform opening and closing functions. The breakers can be either opened or closed manually or electrically. We consider the age of the oil-filled circuit breakers to be the same vintage as the switchgear and transformers.

The main contacts, current carrying components and most of the operating mechanism are submersed in 12.5 imperial gallons of oil and can only be visually inspected by removing the tank. Our records indicate that the internal components have not been inspected and significant component deterioration is expected. Based on the age of the device, the spring tensions and excessive wearing on various shafts, bearings and latches can contribute to trip free and mechanical nuisance problems that affect the reliability of these breakers. Factory replacement parts for this type of breaker are not available and therefore 'used' parts are the only option.

Used parts are difficult to locate for these breakers and often do not work without further modifications.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The existing configuration of the protection devices provides over current protection on the 'A' and 'C' phases along with residual ground fault protection. This protection design was adequate when the system was designed, however, does not provide complete protection for the components of the distribution network supplied by the phase 'B' circuit.

This deficiency can be corrected by adding an additional induction disc relay or upgrading the relay protection to a modern microprocessor based device. A modern microprocessor based device can provide significant advantages to Midland PUC including personnel safety and system reliability through the following:

- Fault Location:
  An event recorder can provide information pertaining to the system prior to the breaker operation, faulted phase, fault type, and general fault location.
- Remote Monitoring and Control
  This requires a supervisory type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VAs, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, breaker controls.

Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear complete with vacuum air circuit breakers and a remote relay panel. Furthermore, we recommend that a transformer and prefabricated switchgear be purchased to simplify the installation.

Battery Bank

The battery bank appears to be within five (5) years old and the general condition of the charger, liquid levels and terminal connections are satisfactory. The output voltage of the existing bank, 120 VDC, is suitable for use with new equipment.

3.7 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below:

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel in proximity to the switchgear from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the pressure, gases away from the operator and areas where personnel generally position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the fault current; however, the configuration of the relay protection devices does not include ground fault protection and relies solely on the over current elements to clear a fault. We recommend upgrading the relay protection to a three (3) phase and ground fault over current protection scheme to provide optimum equipment and personnel protection.

The oil filled circuit breakers utilize a vertical lift type insertion system that requires the door to be open and operator to be directly in front of the breaker in the cell. This inherently places the operator in the most dangerous position if the insertion system or an electrical component(s) fails during its operation or racking onto the live 5kV bus. Furthermore, to manually operate the breaker places the operator in the same position. *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and electrically operated only with the door closed.

3.8 Conclusion

The existing equipment poses a reliability and personnel safety concern. The existing power equipment has provided exceptional service life; however, replacement components and parts are difficult to source which can lead to expensive repairs and extended downtime. Modernizing the substation to meet current Ontario Electrical Safety Code, National Fire Protection and IEEE Standards would increase system reliability and safety to the personnel that operate these devices and the public.

To summarize our assessment, we recommend that a new transformer and switchgear package be installed to replace the existing equipment within one (1) year. To address the concern of future residential and commercial growth, we recommend increasing the capacity of the transformer between 8 to 10 MVA. To comply with the safety requirements outlined by the

Ontario Electrical Safety Code the station ground grid and equipment bonding connections would require upgrading as outlined in our report.

The following is a summary of our recommendations;

1) As per the *Ontario Electrical Safety Code 36- 302*, a minimum of four (4) ground rods are required. We recommend installing two (2) additional ground rods and connecting them to the existing ground loop.

2) As per the *Ontario Electrical Safety Code 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connecting this loop directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.

3) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and tank of each power transformer. The second connection is a redundant bonding connection to ensure the tank remains bonded to the ground grid if an internal fault occurs.

4) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.

5) As per the *Ontario Electrical Safety Code 36-304(5)* and *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection is maintained.

6) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and the operating switch handle to ensure the potential difference is minimized.

7) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.

8) As per the *Ontario Electrical Safety Code 36-312 and Table 52*, we recommend connecting the fence enclosure to the ground grid with a minimum of two (2) connection points.

9) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52*, the ground conductor should be woven throughout the fence fabric in at least two (2) places. We recommend adding spilt bolts to secure the bonding conductor to the fence fabric in at least two (2) places per conductor.

NOTE:

The size of the existing substation is not required for the amount of equipment installed. Additionally, we recommend installing a new fence enclosure around the existing equipment and removing what is not required of the existing fence. This will minimize the costs associated with upgrading the stations ground grid and the connections required to adequately ground and bond the equipment.

10) We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV.
11) We recommend installing a climate control system which would benefit the long-term reliability of the electrical equipment, especially the DC battery bank.
12) Based on the trending results from the oil analysis and preventative maintenance reports, we recommend replacing these transformers in one (1) year and consider the three single phase transformers to have a high potential for failure. We also recommend installing a single three (3) phase 8-10 MVA transformer to meet current and future residential and commercial growth.
13) We recommend installing a residual connected ground fault relay to sense and trip the associated breaker as soon as possible and/or strongly recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a stand alone panel adjacent to the switchgear panel. This will allow personnel to view the relay information without having to be directly in front of the switchgear and will also provide more sensitive protection.
14) Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear with breakers and microprocessor based protection relays. Furthermore, we recommend that a transformer and prefabricated switchgear be purchased to simplify the installation.
15) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and electrically operated only with the door closed.

Section 4

QUEEN STREET SUBSTATION

4.1 System Overview

The Queen Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M4' circuit. It is connected to the gang-operated 46kV air break switch designated 'B37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and one (1) three (3) phase, 5 MVA, power transformer. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via a copper IPC bus. The indoor switchgear has five (5) cells that contain four (4) oil-filled circuit breakers, metering devices, protection and control equipment.

4.2 Ground Grid and Bonding Assessment

The ground grid consists of seven (7) ½ inch diameter, copper ground rods that are interconnected utilizing 4/0 AWG bare copper. It was found during our inspection that a complete loop around the equipment was not completed at the time of construction. One link between two (2) copper rods is required to complete this repair and will satisfy the Ontario Electrical Code requirement. The mechanical connectors used to connect the bare copper wire to the ground rods are suitable for direct burial and in good condition.

The bonding of the equipment to the substation ground grid was found to be as follows:
A connection to each footing of the tower structure, two (2) connections to the transformer tank, one (1) connection to the indoor switchgear, one (1) connection to the lightning arresters, and one (1) connection to the gang-operated high voltage switch but not to the switch handle. The fence fabric was found to be isolated from the ground grid and is grounded via a separate ground loop around the perimeter of the fence. Due to the proximity of the substation ground grid, we recommend that a minimum of two (2) connections between the ground conductor connected to the fence fabric and the substation ground grid be installed, as soon as possible, to prevent a step and touch potential hazard.

The integrity of the fence enclosure was inspected and six (6) fence posts were found broken at ground level and the barbed wire on the south-east corner was also broken. The six (6) broken posts and strand of barbed wire should be replaced, as soon as possible, to prevent unauthorized entry into the substation.

Based on our assessment, we recommend the following deficiencies be corrected:

1) As per the *Ontario Electrical Safety Code 10.002(a), 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connecting this conductor to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.

2) As per the *Ontario Electrical Safety Code 36-302(c)*, we recommend completing the copper loop around the equipment located in the outdoor substation by installing a 4/0 copper link between the two (2) rods located at the east end of the transformer concrete pad.
3) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if a fault occurs.
4) As per the *Ontario Electrical Safety Code 36-304(5)* and *Table 52,* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection.
5) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and operating switch handle to ensure the potential difference is minimized.
6) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
7) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52,* the ground conductor should be woven throughout the fence fabric in at least two (2) places with a maximum of three (3) spans between connections. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two places per conductor.
8) As per the *Ontario Electrical Safety Code 26-300*, we recommend that the six (6) broken fence posts and top strands of barbed wire be replaced, as soon as possible, to prevent unauthorized entry into the substation.

4.3 Tower Structure and Components Assessment

Tower Structure

The condition of the galvanized steel and hardware on the outdoor tower structure was found to be in satisfactory condition.

The current carrying aluminium IPC bus is supported by polymer and porcelain station post insulators. The rating of the insulators and clearances between the bus work and grounded surfaces are suitable for continued service.

No further action is required.

Primary 44kV Air Break Switch

The primary air break switch is rated 48.3kV, 600A with a basic impulse level of 250kV. The ratings of the switch are satisfactory for this application and the product is supported by the manufacturer making replacement parts readily available.

No further action is required.

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by S&C Electric and replacement fuse links are readily available.

The design of the SMD-2C fuses provide adequate short circuit protection, excellent over current protection and is suitable for continued service.

No further action is required.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are a polymer, metal oxide type, intermediate class arrester manufactured by Ohio Brass.

Considering the 5000kVA rating of the power transformer, we recommend upgrading the lightning arresters from an intermediate to station class arrester.

4.4 Transformer Assessment – McGraw Edison, s/n C4620611.

This transformer was purchased in an emergency situation as a 'used' transformer by Midland PUC and its paper insulation had previously undergone significant deterioration prior to Midland PUC's ownership.

The primary 44kV porcelain bushings are in fair condition with damage to one (1) 44kV bushing which has been temporarily repaired. A replacement bushing has been supplied and will be installed.

The result of the Furfuraldehyde (Furan) analysis concludes that the paper insulation is in poor condition. Furans are produced when elevated temperatures cause damage to the paper insulation. In October 2005, the actual furan level was 438 parts per billion (ppb) and had remained relatively stable since April 2003. See our assessment table below.

Rondar Inc. Furan Assessment	
< 100 ppb	Good Condition
250 ppb	Fair to Poor Condition
> 500 ppb	Undergone Severe Deterioration
*ppb = parts per billion	

The results of the dissolved gas-in-oil indicate that the levels of ethylene, carbon monoxide and carbon dioxide have increased; caused by a higher than normal temperature in the insulation. These three (3) gases are produced in conjunction with excessive heating of the paper insulation and provide support our comments regarding furan levels.

We consider the reliability of the transformer to be moderate and without an increase in the supplied load; the transformer is suitable for continued service. However, due to previous damage to the paper insulation, we recommend completing annual oil sampling to monitor the oil properties and dissolved gases. A change in these concentrations would indicate a fault is developing within the transformer and corrective action is required.

4.5 Switchgear and Enclosure Assessment

The indoor switchgear is mounted in a residential style building that is suitable for this application and appears to be in satisfactory condition. The temperature within the building was found to be suitable; however, we recommend installing a climate control system to regulate the inside temperature which would benefit the life span of any electronic devices, especially the DC battery bank.

We request that a company specializing in structure assessments be contacted if further details regarding the structural condition of the building are required.

Switchgear Assessment

The General Electric Switchgear is a Metal Clad type enclosure that is approximately 50 years old. The switchgear contains the following components:

- One set of three (3) metering potential transformers
- One set of three (3) metering current transformers
- Four (4) oil-filled circuit breakers with DC controls
- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers and used for relay protection
- Three (3) phase over current relays per breaker

The main bus work of the switchgear is horizontally mounted in the top front area behind covers. The bus bars are insulated throughout and isolated from each cell by a metal plate. Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration since original construction is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle which can result in cracks or breakage during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment. As above, the components have reached or are near the end of their service life and reliability is questionable. The repair time necessary to locate, investigate and retrofit new control equipment into this switchgear will be time consuming, expensive and significant downtime would be required.

5kV Oil Circuit Breakers (OCB)

The General Electric oil circuit breakers use insulating oil as a dielectric medium to insulate the 'live' parts for metal surfaces and minimize the electric arc during opening/closing operations. During each operation of the breaker, carbon is produced and it slowly contaminates the oil, affecting the dielectric property. This requires the insulating oil to be replaced and increases the annual preventative maintenance costs.

The main contacts, current carrying components and a majority of the operating mechanisms are submersed in 15 U.S. gallons of oil and can only be visually inspected by removing the tank. Our records indicate that the internal components were inspected in 1999; the arcing contact was reported to be in very poor condition. At this time, we would expect significant component deterioration and replacement would be necessary. Furthermore, based on the age of the device, the spring tensions and excessive wearing on various shafts, bearings and latches can contribute to trip free and mechanical nuisance problems that affect the reliability of these breakers. Factory replacement parts for this type of breaker are not available and therefore 'used' parts are the only option. Used parts for these breakers are difficult to locate and often do not work without further modifications.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The existing configuration of the protection devices provides over current protection on the 'A' and 'C' phases along with residual ground fault protection. This protection design was adequate when the system was designed, however, does not provide complete protection for the components of the distribution network supplied by the phase 'B' circuit.

This deficiency can be corrected by adding an additional induction disc relay or upgrading the relay protection to a modern microprocessor based device. A modern microprocessor based device can provide significant advantages to Midland PUC including personnel safety and system reliability through the following:

- Fault Location:
  An event recorder can provide information pertaining to the system prior to the breaker operation, faulted phase, fault type, and general fault location.
- Remote Monitoring and Control
  This requires a supervisory type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VAs, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, breaker controls.

Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend replacing the existing switchgear, breakers and relay protection devices.

Battery Bank

The battery bank appears to be within five (5) years old and the general condition of the charger, liquid levels and terminal connections are satisfactory. The output voltage of the existing bank is 50VDC and would require upgrading to a 120VDC system, if the switchgear is replaced.

4.6 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below:

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel, in proximity to the switchgear, from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the pressure, gases away from the operator and areas where personnel generally position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the fault current; however, the configuration of the relay protection devices does not include ground fault protection and relies solely on the over current elements to clear a fault. We recommend upgrading the relay protection to a three (3) phase and ground fault over current protection scheme to provide optimum equipment and personnel protection.

The oil-filled circuit breakers utilize a vertical lift type insertion system that requires the door to be open and operator to be directly in front of the breaker in the cell. This inherently places the operator in the most dangerous position if the insertion system or an electrical component(s) fails during its operation or racking onto the live 5kV bus. Furthermore, to manually operate the breaker places the operator in the same position. *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and to be electrically operated only with the door closed.

4.7 Conclusion

Based on the results of our assessment and preventative maintenance reports, the condition of the primary switch, fuse and transformer are suitable for continued service at this time. We recommend upgrading the primary lightning arresters to increase the surge protection for the downstream devices. Due to age, availability of replacement parts, maintenance costs and low reliability, we recommend replacing the complete switchgear assembly. Modernizing the substation to meet current Ontario Electrical Safety Code, National Fire Protection and IEEE Standards would increase system reliability and ensure safety to both utility personnel and the general public.

The following is a summary of our recommendations;

1) As per the *Ontario Electrical Safety Code 10.002(a), 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure and connecting this conductor to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.

2) As per the Ontario Electrical Safety Code 36-302(c), we recommend completing the copper loop around the equipment located in the outdoor substation by installing a 4/0 copper link between the two (2) rods located at the east end of the transformer concrete pad.

3) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if a fault occurs.

4) As per the *Ontario Electrical Safety Code 36-304(5)* and *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection.

5) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and operating switch handle to ensure the potential difference is minimized.
6) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
7) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52*, the ground conductor should be woven throughout the fence fabric in at least two (2) places and a maximum of three (3) spans between connections. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two (2) places per conductor.
8) As per the *Ontario Electrical Safety Code 26-300*, we recommend that the six (6) broken fence posts and top strands of barbed wire be replaced, as soon as possible, to prevent unauthorized entry into the substation.
9) Considering the 5000kVA rating of the power transformer, we recommend upgrading the lightning arresters from an intermediate to station class arrester.
10) We recommend installing a climate control system to regulate the inside temperature of the building which would benefit the life span of any electronic devices, especially the DC battery bank.
11) We consider the reliability of the transformer to be moderate and without an increase in the supplied load; the transformer is suitable for continued service. However, due to previous damage to the paper insulation, we recommend completing annual oil sampling to monitor the oil properties and dissolved gases. A change in these concentrations would indicate a fault is developing within the transformer and corrective action is required.
12) Based on our assessment of the metal clad switchgear, oil-filled circuit breaker, induction disc relays and various components, we recommend installing new switchgear complete with vacuum air circuit breakers and a stand alone relay panel.
13) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be racked in or removed from energized bus work and to be electrically operated only with the door closed.

Section 5

FOURTH STREET SUBSTATION

5.1 System Overview

The Fourth Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M4' circuit. It is connected to the gang-operated 46kV air break switch designated 'A37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and one (1) three phase, 3 MVA, power transformer. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via a three (3) conductor cable. The indoor switchgear has six (6) cells that contain three (3) oil-filled circuit breakers, metering device, protection and control equipment.

5.2 Ground Grid and Bonding Assessment

The ground grid consists of five (5) ¾ inch diameter, copper ground rods that are interconnected utilizing 4/0 AWG bare copper and forms a loop around the equipment located in the substation. The mechanical connectors used to connect the bare copper wire to the ground rods are suitable for direct burial and are in good condition.

The bonding of the equipment to the substation ground grid was found to be as follows:
A connection to each footing of the tower structure, two (2) connections to the transformer tank, one (1) connection to the indoor switchgear, one (1) connection to the lightning arresters and one (1) connection to the gang-operated high voltage switch but not to the switch handle. The fence fabric was found to be connected to the ground grid and requires the connections to the fence fabric and barbed wire to be revamped to meet the Ontario Electrical Safety Code.

The integrity of the fence enclosure was inspected and found to be generally in suitable condition but does not prevent unauthorized entry. A significant gap located between the south corner fence post and the north wall of the Parks and Recreation Building would allow a smaller person to gain entry into the substation. A temporary solution should be developed and administered, as soon as possible, to ensure public safety.

Based on our assessment, we recommend the following deficiencies be corrected:

1) As per the *Ontario Electrical Safety Code 10.002(a), 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure, where possible, and connect this conductor to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
2) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.

3) As per the *Ontario Electrical Safety Code 36-304(5)*and *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection.
4) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and the operating switch handle to ensure the potential difference is minimized.
5) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
6) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52,* the ground conductor should be woven throughout the fence fabric in at least two (2) places and maximum of three (3) spans between connections. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two (2) places per conductor.

5.3 Tower Structure and Components Assessment

The condition of the galvanized steel and hardware on the outdoor tower structure was found to be in satisfactory condition.

The current carrying bus work is copper IPC and supported by polymer station post and porcelain cap and pin style insulators. The clearances between the bus work and grounded surfaces are suitable for continued service, however, we recommend replacing the cap and pin insulators as soon as possible. We have experienced a higher than normal failure of this type of insulator and believe it to be a result of natural deterioration.

Primary 44kV Air Break Switch

The primary air break switch is rated for 46kV and 600 amperes. The ratings of this switch are satisfactory for the application; however, this product is no longer supported by the manufacturer, making replacement parts unavailable. The design of the switch is as an air break switch and does not have load breaking capabilities and requires a key interlock system to prevent operation of the switch under load. Our preventative maintenance reports indicate that the silver plating on the main contact surfaces and current carrying flex braids have significantly deteriorated.

Based on the unavailability of parts, manufacturer support and the condition of the existing switch, we recommend upgrading the air break switch to an S&C, Alduti Rupter, load break switch rated for a maximum voltage of 48.3kV with a continuous current of 600A and interrupt capacity of 40000 amperes.

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by General Electric and have since been discontinued.

Based on the availability of parts and manufacturer support, we recommend upgrading the primary fuses to an S&C, SMD fuse assembly.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are of a porcelain gap type constructed arrester and manufactured by General Electric. The gap type arrester is prone to failure due to moisture ingress into the semi-conductive material within the unit. The moisture reduces the resistance of the components with the arresters directly affecting the kV and maximum continuous operating voltage (M.C.O.V.) rating of the device and the reliability of surge protection.

We recommend replacing the three (3) lightning arresters with polymer, metal oxide, station class arresters rated for 48kV and 39 MCOV.

5.4 Transformer Assessment – General Electric, s/n 280019.

The General Electric power transformer, s/n 280019, has a capacity of 3 MVA and is configured with a primary 44000 volt, delta connected primary winding and a secondary 4160 volt, wye configured, winding. The secondary neutral bushing is directly connected to the substation ground grid and is commonly referred to as a "solidly grounded Wye system". The General Electric transformer was constructed in 1954 and has provided service for approximately 52 years.

The south side of the concrete pad that supports the transformer has shifted resulting in that side of the pad settling lower into the ground. This causes the transformer to lean and is presently at an approximate 5 to 10 degree angle. This can affect the cooling of the dielectric fluid and can cause the transformer to operate at a higher temperature.

The primary 44kV porcelain bushings are in poor condition with evidence of tracking on the H2 and H3 bushings. At the time of the last inspection, the insulation resistance of the bushings had not been affected however, integrity and reliability are questionable.

The result of the Furfuraldehyde (Furan) analysis concludes that the paper insulation is in poor condition. Furans are produced when elevated temperatures cause damage to the paper insulation. In October 2005, the actual furan level was 301 parts per billion (ppb) and had increased since October 2003. See our assessment table below.

Rondar Inc. Furan Assessment	
< 100 ppb	Good Condition
250 ppb	Fair to Poor Condition
> 500 ppb	Undergone Severe Deterioration
*ppb = parts per billion	

The results of the dissolved gas-in-oil indicate that the levels of carbon monoxide and carbon dioxide had increased due to a higher than normal temperature in the insulation. These gases are produced in conjunction with excessive heating of the paper insulation and support our comment regarding furan levels.

Based on the moderate degradation of the paper insulation and the condition of primary bushings, we recommend replacing the transformer within one (1) year. We also recommend that the oil filled lead secondary cable connecting the transformer to the indoor switchgear be replaced at this time.

5.5 Switchgear and Enclosure Assessment

The indoor switchgear is mounted within a commercial building that is suitable for this application and appears to be in satisfactory condition. The temperature within the building was found to be acceptable.

We request that a company specializing in structure assessments be contacted if further details regarding structural condition of the building are required.

5.6 Switchgear Assessment

The General Electric Switchgear is a Metal Clad type enclosure that is approximately 50 years old. The switchgear contains the following components:

- One set of three (3) metering potential transformers
- One set of three (3) metering current transformers
- Three (3) oil-filled circuit breakers with DC controls
- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers and used for relay protection.
- Three (3) phase over current relays per breaker

The main bus work of the switchgear is horizontally mounted in the top front area behind covers. The bus bars are insulated throughout and isolated from each cell by a metal plate. Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration since original construction is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle which can result in the insulation starting to crack or break during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment. As above, the components have reached or are near the end of their service life and their reliability is questionable. The repair time necessary to locate, investigate and retrofit in new control equipment into this switchgear will be time consuming, expensive and significant downtime would be required.

5kV Oil Circuit Breakers (OCB)

The General Electric oil blast circuit breakers use insulating oil as a dielectric medium to insulate the 'live' parts from metal surfaces and minimize the electric arc during opening/closing operations. The breaker consists of six (6) bushings, two (2) sets of contacts per phase, one (1) closing coil (cc), one (1) tripping coil (tc) and necessary operating mechanisms to perform opening and closing functions. The breakers can be either opened or closed manually or electrically. We consider the age of the oil-filled circuit breakers to be the same vintage as the switchgear and transformer.

The main contacts, current carrying components and a majority of the operating mechanisms are submersed in 15 U.S. gallons of oil and can only be visually inspected by removing the tank. We do not have any records of an inspection of the internal components of the breakers. Furthermore, based on the age of the device, the spring tensions and excessive wearing on various shafts, bearings, latches and contact surfaces can contribute to trip free and mechanical nuisance problems that affect the reliability of these breakers. Factory replacement parts for this type of breaker are not available and therefore 'used' parts are the only option. Used parts are difficult to locate for these breakers and often do not work without further modifications.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The design of the protection system incorporates three (3) bar type current transformers, one per phase per breaker, that provide a current signal to each phase over current relay. Each breaker is equipped with one (1) over current relay per phase, however, is not equipped with a relay to sense a ground fault on the system. This is an error in the design of the relay protection system which can result in significant equipment damage in the event of a ground fault. The 4160 volt system is a solidly grounded wye system and based on the present relay settings, an electrical arc could develop between any one (1) phase and ground before the relay protection recognizes a fault is occurring. Whether or not the ground fault is sensed, depends solely on the resistance of the ground fault, $I=V/R$, with the resistance being variable. Furthermore, the existing protection may not sense a ground fault until it develops into a two (2) phase or three (3) phase fault; resulting in significant equipment damage.

The induction disc relays have provided an exceptional service life but are limited to visual indication of the protection function that operates during a fault. Upgrading the relay protection to a modern microprocessor based device can provide significant advantages to Midland PUC, personnel safety, system protection and reliability through the following:

- Fault Identification
  An event recorder can provide information pertaining to the system prior to the breaker operation, faulted phase, fault type, and general fault location.
- Remote Monitoring and Control
  This requires a supervisory type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VAs, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, breaker controls.

Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear, breakers and protection relays.

Battery Bank

The battery bank appears to be within five (5) years old and the general condition of the charger, liquid levels and terminal connections are satisfactory. The output voltage of the existing bank is 50VDC and would require upgrading to a 120VDC system, if the switchgear is replaced.

5.7 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below.

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel in proximity to the switchgear from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the pressure, gases away from the operator and areas where personnel generally position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the rated current; however, the configuration of the relay protection devices does not include three (3) phase over current protection and relies solely on the over current elements to clear a fault on the phase 'B'. We recommend upgrading the relay protection to a three (3) phase and ground fault over current protection scheme to provide optimum equipment and personnel protection.

The oil-filled circuit breakers utilize a vertical lift type insertion system that requires the door to be open and operator to be directly in front of the breaker in the cell. This inherently places the operator in the most dangerous position if the insertion system or an electrical component(s) fails during its operation or racking onto the live 5kV bus. Furthermore, to manually operate the breaker places the operator in the same position. *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/risk assessment, we recommend that the breakers not be inserted or removed from energized bus work and electrically operating the breaker(s) only with the door closed.

5.8 Conclusion

Based on the results of our assessment and preventative maintenance reports, we recommend replacing the complete substation from the 44kV incoming feeder to the 5kV feeder cables. All of the major and minor components are obsolete and deteriorated to the point of replacement. Modernizing the substation to meet current Ontario Electrical Safety Code, National Fire Protection and IEEE Standards would increase system reliability and ensure safety to both utility personnel and the general public.

The following is a summary of our recommendations;

1) As per the *Ontario Electrical Safety Code 10.002(a), 36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure, where possible, and connect this conductor to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
2) With reference to the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.
3) As per the *Ontario Electrical Safety Code 36-304(5)* and *Table 52* and in the interest of personnel safety, we recommend removing the yard debris (i.e. leaves), applying a herbicide and adding three (3) inches of crushed stone to the substation to ensure the dielectric protection.
4) As per the *Ontario Electrical Safety Code 36-310(1)*, we recommend installing flexible connections between the ground grid and the operating switch handle to ensure the potential difference is minimized.

5) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.

6) As per the *Ontario Electrical Safety Code 36-312(4) and Table 52,* the ground conductor should be woven throughout the fence fabric in at least two (2) places and a maximum of three (3) spans between connections. We recommend adding split bolts to secure the bonding conductor to the fence fabric in at least two (2) places per conductor.

7) We recommend replacing the cap and pin insulators as soon as possible. We have experienced a higher than normal failure of this type of insulator and believe it to be a result of natural deterioration.

8) Based on the unavailability of parts, manufacturer support and the condition of the existing switch, we recommend upgrading the air break switch to an S&C, Alduti Rupter, load break switch rated for a maximum voltage of 48.3kV with a continuous current of 600A and interrupt capacity of 40000 amperes.

9) Based on the availability of parts and manufacturer support, we recommend upgrading the primary fuses to a S&C, SMD fuse assembly

10) We recommend replacing the three (3) lightning arresters with polymer, metal oxide, station class arresters rated for 48kV and 39 MCOV.

11) Based on the moderate degradation of the paper insulation and the condition of primary bushings, we recommend replacing the transformer within one (1) year. We also recommend that the oil filled lead secondary cable connecting the transformer to the indoor switchgear be replaced at this time.

12) Based on our assessment of the metal clad switchgear, oil-filled circuit breakers, induction disc relays and various components, we recommend installing new switchgear, breakers and protection relays.

13) We recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a stand alone panel adjacent to the switchgear panel. This will allow personnel to view the relay information without having to be directly in front of the switchgear and provide more sensitive protection.

14) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/risk assessment, we recommend that the breakers not be inserted or removed from energized bus work and electrically operating the breaker(s) only with the door closed.

Section 6

MONTREAL STREET SUBSTATION

6.1 System Overview

The Montreal Street Substation is supplied by the Hydro One 44kV Feeder designated as the 'M4' circuit. It is connected to the gang-operated 48.3kV load break switch designated 'E37T1-L' located at the station. The equipment located in the outdoor substation consists of one (1) gang-operated air break switch, one (1) set of three (3) lightning arresters, one (1) set of three (3) over current protection fuses and one (1) three phase, 10 MVA, power transformer. The secondary of the transformer is directly connected to the main bus of the indoor switchgear via a metal enclosed bus duct. The indoor switchgear has six (6) cells that contain five (5) circuit breakers, metering devices, protection and control equipment.

6.2 Ground Grid and Bonding Assessment

The ground grid consists of four (4) ¾ inch diameter, copper ground rods that are interconnected utilizing 4/0 AWG bare copper and forms a loop around the equipment located in the substation. The mechanical connectors used to connect the bare copper wire to the ground rods are suitable for direct burial and are in good condition. No further action is required

The bonding of the equipment to the substation's ground grid was found to be as follows:

A connection to each footing of the tower structure; two (2) connections to the transformer tank; one (1) connection to the indoor switchgear, one (1) connection to the lightning arresters and one (1) connection to the gang-operated high voltage switch and switch handle. The fence, fence fabric, posts and barbed wire were found to be connected to the ground grid and meet the requirements of the Ontario Electrical Safety Code. No further action is required

The integrity of the fence prevents unauthorized entry into the substation, therefore, provides adequate protection to the public. No further action is required.

Based on our assessment, we recommend the following deficiencies be corrected:

1) As per the *Ontario Electrical Safety Code 10.002(a),36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure, where possible, and connect this conductor directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
2) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.
3) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.

6.3 Tower Structure and Components Assessment

Aluminium Tower Structure

The condition of the aluminium outdoor tower structure is presently in good condition. The visual inspection of the two (2) concrete footings and tower bases concluded there is no significant deterioration.

The current carrying bus work is four (4) inch aluminium IPC and supported with porcelain station post style insulators. The insulation rating and clearances between the primary buses and grounded surfaces are suitable for the voltage rating.

No further action is required.

Primary 44kV Air Break Switch

The air break switch located on the top of the tower structure was manufactured by CLM Industries and as per our preventative maintenance reports, the condition of the current carrying components are suitable for continued service.

The voltage, current and basic impulse level of the switch is suitable for the application and suitable for continued service

Primary Fuse Protection

The primary protection fuses mounted vertically on the tower structure are manufactured by S&C Electric and replacement fuse links are readily available, if required.

The short circuit, voltage and over current ratings the fuse units provide excellent equipment protection and are suitable for this application.

No further action is required.

Lightning Arresters

The three (3) lightning arresters located on the tower structure and connected to the 44kV bus work are of a polymer, metal oxide type arrester and manufactured by General Electric.

We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV.

6.4 Transformer Assessment – Northern Transformer, s/n 290-711.

The Northern Transformer power transformer, s/n 290-71, has a capacity of 10 MVA and is configured with a primary 44000 volt, delta connected primary winding and a secondary 4160 volt, wye configured winding. The secondary neutral bushing is directly connected to the substation ground grid and commonly referred to as a “solidly grounded Wye system”. This transformer was constructed in 1990 and has provided approximately 16 years of service.

Based on the inspection and test results from the 2005 preventative maintenance, the condition of the transformer is satisfactory.

The results of the standard, water content, dissolved gas-in-oil and furan analyses conclude that the fault gas and oil properties are within normal operating limits and suitable for continued service.

We consider the transformer to have a low potential for failure and at this time no further action is required.

6.5 Enclosure Assessment

The indoor switchgear is mounted within a residential style building that is suitable for this application and appears to be in satisfactory condition. The temperature within the building was found to be suitable; however, we recommend installing a climate control system to regulate the inside temperature which would benefit the life span of any electronic devices.

We request that a company specializing in structural assessments be contacted if further details regarding structural condition of the building are required.

6.6 Switchgear Assessment

Switchgear Enclosure

The CLM Industries switchgear is a Metal Clad type enclosure that is approximately 20-25 years old. The switchgear contains the following components:

- One set of three (3) metering potential transformers.
- One set of three (3) metering current transformers.
- Five (5) breakers with DC controls.
- Three (3) bar type current transformers per breaker. The current transformers are mounted on the load side bus of the breakers and used for relay protection.
- Three (3) phase over current relays per breaker.

The main bus work of the switchgear is horizontally mounted in the bottom rear area behind covers.

Our preventative maintenance reports have concluded that the measured insulation resistance, with reference to the *NETA Standard Table 10.1*, is suitable for continued service. Based on the age of the insulation and assuming a moderate temperature, the elasticity of the insulation has deteriorated. The amount of deterioration since original construction is unknown and it is difficult to visually inspect the main bus work due to barriers. As the elasticity properties of the insulation deteriorates, it causes the insulation to become brittle which can result in the insulation starting to crack or break during a fault.

The components and wiring of the switchgear are operating as required to provide the necessary control power to the associated equipment.

We consider the reliability of the switchgear and its components to have a low potential for failure, however, recommend completing breaker timing tests to measure the contact travel time, rebound and actual opening time to ensure the operating mechanism is functioning within the manufacturer's recommended limits.

A serious safety hazard is present involving the cable connections between the main secondary bus duct from the outdoor transformer and the cell designated 'Main B'. The stress cones at both ends of the cables are left unguarded and in open air, lying on the top cover of the switchgear. The potential for equipment damage, electrical shock or serious injury could occur if the area is accidentally contacted. We recommend removing the existing cables and installing them into the back of the switchgear and routing them through the cable pit to the 'Main B' switchgear cell. Furthermore, power fuses should be installed to protect the cable and to co-ordinate with the primary transformer protection fuses. Installing fuses will ensure that a cable fault will not disrupt the entire distribution system.

5kV Air Circuit Breakers

The type of circuit breaker, voltage, continuous current, interrupt capacity and basic impulse level (BIL) meet the requirements of the supply system and are suitable for continued service.

Based on comments from our previous reports, we consider the reliability of the switchgear and its components to be suitable for continued service.

Relay Protection

A solidly grounded system provides a high level of safety and fault detection when the proper protective devices are applied and coordinated correctly. The design of the protection system incorporates three (3) bar type current transformers, one per phase per breaker, that provide a current signal to each phase over current relay. Each breaker is equipped with one (1) over current relay per phase, however, is not equipped with a relay to sense a ground fault. This is an error in your protection system that can result in significant equipment damage in the event of a ground fault. The 4160 volt system is a solidly grounded wye system and based on the present relay settings, an electrical arc could develop between any one (1) phase and ground before the relay protection recognizes a fault is occurring. Whether or not the ground fault is sensed, depends solely on the resistance of the ground fault, I=V/R, with the resistance being variable. Furthermore, the existing protection may not sense a ground fault until it develops into a two (2) phase or three (3) phase fault.

The induction disc relays have provided an exceptional service life but are limited to visual indication of the protection function that operates during a fault.

Upgrading the relay protection to modern microprocessor based devices can provide significant advantages to Midland PUC, personnel safety, system protection and reliability through the following:

- Fault Identification
  An event recorder can provide information pertaining to the system prior to the breaker operation, faulted phase, fault type, and general fault location.
- Remote Monitoring and Control
  This requires a supervisory type communication between the relay and a remote location. This can provide a variety of information such as: voltages, currents, watts, Vars, VAs, device status, remote operation (i.e. hold offs) and can be configured to meet your requirements.
- Equipment Protection (Voltage and Current):
  More sensitive relay settings can be applied to provide optimum equipment protection.
- Other Available Features:
  Re-closure, synchronism check, directional elements, frequency check, breaker controls.

We recommend installing a residual connected ground fault relay to sense and trip the associated breaker, as soon as possible, and/or strongly recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a stand alone panel adjacent to the switchgear panel. This will allow personnel to view the relay information without having to be directly in front of the switchgear and provide more sensitive protection.

6.7 Arc Flash Protection (NFPA 70E)

Generally, the equipment meets the requirements of the *National Fire Protection Association Code 70E (NFPA 70E)*, except as noted below:

With reference to *Annex K of the NFPA 70E*, the design of medium voltage metal clad switchgear does not provide an arc pressure relief device(s) that would allow the pressures developed during an internal arc to be vented away safely from the front and rear of the switchgear. This feature assists in the protection of personnel in proximity to the switchgear from dangerous temperatures and the pressures that are developed when an internal arc flash occurs. The vent(s) or flaps are designed and placed in areas that safely direct the pressure, gases away from the operator and areas where personnel general position themselves.

Article 210.5 and 410.9(B)(1)(a) recommends that the protective devices be maintained and able to withstand or interrupt the available fault current and provide proper current protection. The breakers, current transformers and relays are suitable to interrupt the rated current; however, the configuration of the relay protection devices does not include ground fault protection. As stated above, we recommend upgrading the relay protection to include ground fault protection that would increase the safety of your distribution system and personnel.

The CLM air circuit breakers are mounted on a truck assembly that allows the breaker to be inserted and removed on a horizontal track system. In order to insert or remove the breaker from the cell, the operator must access the racking mechanism by opening the cell door. This inherently places the operator in the most dangerous position if the insertion system or an electrical component(s) fails during its operation or racking onto or off of live 4160V bus. Furthermore, to manually operate the breaker places the operator in the same position.

NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above" assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be inserted or removed from energized bus work and electrically operating the breaker(s) only with the door closed.

6.8 Conclusion

Our assessments indicate that minor upgrades to equipment bonding, relocation of the 'Main B' power cables and installation of ground fault protection relays to improve the safety of your electrical distribution system are required. We recommend your consideration to upgrade the existing induction disc relays with a microprocessor based system that would provide more information pertaining to the daily operation of the power system.

The following is a summary of our recommendations:

1) As per the *Ontario Electrical Safety Code 10.002(a),36-312(1) and Table 52*, we recommend installing a ground conductor that loops one (1) metre outside the perimeter of the existing substation metallic fence enclosure, where possible, and connect this conductor directly to the substation ground grid. This ensures that the step and touch potential between the metallic fence and one (1) metre from the fence is minimized and eliminates a potential shock hazard during a fault.
2) As per the *Ontario Electrical Safety Code 36-308(2)(b)*, we recommend installing a second bonding connection between the ground grid and ground bus within the switchgear. The second connection is a redundant bonding connection to ensure the switchgear remains bonded to the ground grid if an external and/or internal fault occurs.
3) We recommend upgrading the bonding connection between the three (3) lightning arresters located on the tower structure to include a continuous loop to a second connection to the ground grid. A second connection provides a redundant path to discharge equipment damaging voltages and currents during a severe power surge.
4) We recommend replacing the three (3) lightning arresters with polymer, metal oxide station class arresters rated for 48kV and 39 MCOV.
5) We consider the reliability of the switchgear and its components to have a low potential for failure, however, recommend completing a breaker timing test to measure the contact travel time, rebound and actual opening time to ensure the operating mechanism is functioning within the manufacturer's recommended limits.

6) A serious safety hazard is present involving the cable connections between the main secondary bus duct from the outdoor transformer and the cell designated 'Main B'. The stress cones at both ends of the cables are left unguarded and in open air, lying on the top cover of the switchgear. The potential for equipment damage, electrical shock or serious injury could occur if the area is accidentally contacted. We recommend removing the existing cables and installing them into the back of the switchgear and routing them through the cable pit to the 'Main B' switchgear cell. Furthermore, power fuses should be installed to protect the cable and to co-ordinate with the primary transformer protection fuses. Installing fuses will ensure that a cable fault will not disrupt the entire distribution system.

7) We recommend installing a residual connected ground fault relay to sense and trip the associated breaker, as soon as possible, and/or strongly recommend modernizing the protection relays to a microprocessor based device and mounting the relays in a stand alone panel adjacent to the switchgear panel. This will allow personnel to view the relay information without having to be directly in front of the switchgear and provide more sensitive protection.

8) *NFPA 70E, Table 130.7(C)(9)(a), page 70E-31, for "Metal Clad Switchgear, 1kV and Above"* assesses the hazard/risk of the manual operation, insertion and removal of this type of breaker from live bus work to be their highest category of 4. Based on the hazard/ risk assessment, we recommend that the breakers not be inserted or removed from energized bus work and electrically operating the breaker(s) only with the door closed.

RONDAR INC.

Section 7

2005 & 2003 MAINTENANCE REPORTS
Fourth, Queen & Montreal Street Substations

RONDAR INC.

January 5, 2006

Midland PUC
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**

Subject: **Preventive Maintenance @ Fourth, Queen and Montreal Street Substations**
Our Ref. C1616

Dear Sir:

We are enclosing the results of the maintenance carried out at the Fourth, Queen and Montreal Street substations on October 17th, 18th & 19th, 2005, respectively.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in the comments and recommendations.

If you have any questions or require further information, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown, A.Sc.T.
Technical Service Representative

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

1. The galvanization of the tower structure located in the outdoor substation has depleted. Although the deterioration is not a safety issue at this time, we recommend that it be monitored on a regular basis to ensure the integrity of the structure is not jeopardized.

2. The outdoor substation yard was found to have an excess of debris within it. We recommend that qualified personnel clean out this debris on a regular basis to ensure the dielectric properties of the yard.

3. The outdoor substation yard was found to have an excess of weeds growing within it. We recommend that an herbicide be applied annually to control this on-going problem and to ensure the dielectric properties of the crushed stone.

4. The depth of the crushed stone in the outdoor substation yard was found to be low. As per the Ontario Electrical Safety Rule 36-304 (5), we recommend that 150mm of crushed stone be added to the substation yard as soon as possible.

5. The fence enclosure surrounding the outdoor substation yard was found damaged. The top rail barbed wire holder was found broken and the corresponding middle rail was severely bent. We recommend that these items be repaired, as soon as possible, to ensure that unauthorized personnel do not gain entry into this area.

6. The main access gate and the man gate were found to be without corresponding bonds to ground. As per the Ontario Electrical Safety Rule 36-312 (3), we recommend that these grounds be installed, as soon as possible, to ensure that the touch potential of this enclosure stay within acceptable limits.

7. As previously reported, the flexible braided shunts on the high voltage air break switch located on the tower structure were found to be deteriorating. Due to the excessive deterioration, we recommend to replace these shunts during your next shutdown to ensure proper operation of the air break switch and prevent a potential failure

8. The insulators of the High Voltage Air Break Switch on the top of the tower were found contaminated with a type of carbon spray from the arcing whips operation. This has not affected their insulation value nor is it an immediate concern, but it should be noted since this problem will only get worse each time the switch is operated under potential. The remaining insulators appear to be significantly weathered and we recommend annual inspection.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

9. The stationary and moving contact surfaces on the 'B' phase primary fuse located on the tower were found to have severe pitting. The contact surfaces were refurbished as much as possible during the last maintenance, however, the pitting seems to have reappeared. We recommend that this pitting be re-inspected during the next maintenance to monitor the severity of this problem.

10. It was noted that there is no Silica Gel Breather located on the Main Transformer, s/n 280019. As the temperature and load for this transformer increases and decreases, the oil level rises and falls creating a breathing effect. As the transformer "breathes", the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

11. Evidence of tracking was found on the H2 and H3 high voltage bushings for the Main Transformer, s/n 280019 during the 2003 preventative maintenance and at this time no further deterioration has occurred. The insulation resistance value of the primary windings and bushings indicate that the insulation resistance has not deteriorated since the previous inspection; however, the integrity of the bushings remains questionable. We recommend replacing the three (3) primary bushings, as soon as possible, to prevent equipment failure during operation. Due to the age of this transformer, a replacement bushing would be difficult to locate in an emergency situation.

12. Fresh oil was found around both of the sample valves at the bottom of the tank on the Main Transformer, s/n 280019, which was also encountered during the 2003 preventative maintenance. The oil residue was removed and we recommend periodic inspection to determine the severity.

13. The paint condition of the Main Transformer, s/n 280019, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

14. The concrete pad of the Main Transformer was found to be sitting at an angle and will start to affect the effectiveness of the cooling radiators. We recommend levelling the transformer, as soon as possible, to ensure the heat can be dissipated from the oil as the manufacturer's design was intended.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

15. The results of the standard analysis of the insulating fluid in the Main Transformer, s/n 280019, indicate that the interfacial tension and dielectric properties of the oil are below the minimum rating and the measured neutralization number is approaching the maximum limit. The results conclude that there is oxidization occurring and that polar contaminates are present within the oil. We recommend completing an inhibitor analysis, as soon as possible, to assess the level of oxidation resistance in the insulating fluid. Furthermore, based on previous results, our perception is that the oil has reached the end of its service life and a retro fill is recommended for continued service reliability.

16. The results of the dissolved gas-in-oil analysis on the Main Transformer, s/n 280019, indicate that the levels of carbon monoxide and carbon dioxide have increased since December 2003 and are a result of higher than normal temperature in the paper insulation. We recommend procuring a dissolved gas-in-oil sample in April 2006 to monitor and trend the gas content. The results will be used to further predict the end of service life of this transformer.

17. The results of the furan analysis on the Main Transformer, s/n 280019, indicate that the level of furans has increased since October 2003 indicating that the paper insulation has been subjected to heat stress during this time period. The furfuraldehyde (Furan) level has increased from 230 ppm (2003) to 301 ppm (2005) and is increasing at a rate of 1 PPB per day. The level of furans at this time is assessed as moderate deterioration of the paper insulation with a maximum level of 500 ppm. Based on previous furan results, trending for this transformer, the maximum furan level and the rate of rise of the furan gases, the reliable service life of the transformer has passed and replacement will be necessary within one (1) year. In the interim, we recommend procuring a sample for furan analysis in April 2006 to confirm the rate of rise to further predict the end of service life.

18. The entrance door to the indoor substation room was found to be missing a ground connection to a corresponding ground bus in this room. We recommend installing a ground bus in this room as well as bonding the door to ground, as soon as possible, to ensure that all non-current carrying components are bonded to ground.

19. The end cabinet of the indoor switchgear was found to be full of old equipment. We recommend that this debris be cleared out of this cell to ensure that no extra equipment be damaged or create a hazard during an emergency situation.

20. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and table 52, we recommend that a rubber switching mat be installed, as soon as possible, directly in front of the breaker cells to maintain a tolerable level of step and touch potential.

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COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

21. We recommend that a co-ordination study be completed involving all of the electrical protection equipment associated with the Fourth Street Substation. The relays were tested and calibrated as per Midland PUC requirements; however, a study would verify proper co-ordination of the protective devices and a settings table that the relays would be calibrated to during the preventative maintenance inspection.

22. The standard oil analysis for the Feeder #2 oil circuit breaker, s/n 39697, concluded that the insulating properties of the fluid are within normal operating limits. We recommend sampling as per your maintenance schedule.

23. The Feeder #2 oil circuit breaker, s/n 39697, Phase 'A' load side bushings was found to have been taped top to bottom which was completed by another contractor before Rondar serviced this location. Regular electrical tape is not a recommended insulation material used in high voltage repair work and defeats the electrical insulation of the high voltage bushing. We recommend sourcing a suitable replacement bushing and installing as soon as possible.

24. The standard oil analysis for the Feeder #3 oil circuit breaker, s/n 39695, and Feeder #4 oil circuit breaker, s/n 39696, concluded that the dielectric breakdown is low for high voltage rating. We recommend replacing the insulating oil in each breaker at your earliest convenience. Furthermore, our records indicate that the internal mechanism of these breakers have not been inspected since 1999 and in conjunction with the oil replacement, we recommend completing an internal inspection of the operating mechanisms to identify defective components.

25. The instantaneous element on the phase 'B' protective relay for Feeder #3 was found to be defective. We recommend replacing the protection relay, as soon as possible, to ensure equipment protection.

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COMMENTS AND RECOMMENDATIONS

Queen Street Substation

1. The barbed wire surrounding the outdoor substation was found broken. We recommend replacing the broken areas of barbed wire, as soon as possible, in order to prevent access to unauthorized personnel.

2. The fence fabric located in the northwest corner of the substation was found without a ground conductor woven through it. As per the Ontario Safety Code 36-312(4), we recommend a ground conductor be woven through the fence fabric with corresponding connections to the top rail, as soon as possible, to ensure all metal, non-current carrying components are bonded to ground.

3. The outdoor substation yard was found with excessive weed growth. As per the Ontario Electrical Safety Code 36-304(5), Table 52, we recommend that the yard debris and weeds be removed and 50-75mm of 19mm crushed stone be added, as soon as possible, to prevent the step and touch potential from exceeding acceptable tolerances.

4. The paint condition of the Main Transformer, s/n C-46206-1, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

5. The standard oil sample analysis results for the Main Transformer, s/n C-46206-1, indicate that the insulating properties of the oil are suitable for continued service. We recommend sampling as per your preventative maintenance schedule.

6. The dissolved gas analysis results for the Main Transformer, s/n C-46206-1 indicate that the acetylene level has decreased. The ethylene, carbon monoxide and carbon dioxide have increased since May 2003 indicating a high temperature thermal fault most likely involving the paper insulation. The combustible gas content is increasing at a rate of approximately 1 ppm/day indicating that the fault is not severe at this time. We recommend re-sampling for dissolved gases in April 2006 to monitor the gas content.

7. The furan sample analysis results for the Main Transformer, s/n C-46206-1, indicate that the fururaldehyde (furan) level has remained relatively stable since April 2003 indicating that the paper insulation has not been subjected to heat stress during this period, however, the present level indicates the insulation has sustained extensive deterioration. We recommend sampling as per your preventative maintenance schedule.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Queen Street Substation

8. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and Table 52, we recommend that a rubber switching mat be installed directly in front of the breaker cells, as soon as possible, in order to maintain a tolerable level of step and touch potential.

9. As previously reported, the arcing contacts (stationary and moving) on the oil circuit breakers designated CCT#2, CCT#3 and CCT#4 were found to have deteriorated, however, the arcing contacts on the oil circuit breaker designated CCT#1 were found to be in very poor condition in comparison to the other breakers. Based on our service records of the four (4) oil circuit breakers, we insist that the internal mechanism be inspected during the next preventative maintenance shutdown to ensure the mechanism is suitable for continued service and replacing the stationary and moving arcing contacts on the oil circuit breaker designated CCT#1, s/n 37213, to prevent a failure from occurring.

10. The oil analysis results completed on the four (4) indoor oil circuit breakers, Circuit #1, s/n 37213, Circuit #2, s/n 37214, Circuit #3, s/n 37211, and Circuit #4, s/n 37212, indicate that all oil properties are within normal operating limits and suitable for continued service.

11. During testing of the Neutral over current relay for CCT #1, it was found to have resistance of the magnetic disk which impeded the operational characteristics of the relay and directly affected the current pick-up. This relay was replaced and the original settings were reapplied and left in satisfactory condition.

12. During testing of the Neutral over current relay for CCT #2, the current pick-up was found to exceed the manufacturer's recommend limits. At the request of Midland PUC personnel, the current pick-up was re-calibrated and left in satisfactory condition.

13. During testing of the Red phase over current relay for CCT #2, the seal-in unit was found to be defective. We recommend that this unit be replaced, as soon as possible, to ensure proper breaker operation in the event of a fault.

14. During the calibration testing of the neutral over current relay for CCT #3, the current pick-up was found to exceed the manufacturer's recommended limits. At the request of Midland PUC personnel, the current pick up was re-calibrated and left in satisfactory condition.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Montreal Street Substation

1. The weed growth in the main outdoor substation was found to be suitable and we recommend applying an herbicide in April or May 2006 to prevent any new weed growth.

2. The sample valve located close to the bottom of the tank for the Main Transformer, s/n 90-711, was found with a small amount of oil residue around the valve and fittings. The presence of fresh oil was observed around the valve but is not serious at this time. We recommend continued monitoring of this oil leak.

3. The results of the dissolved gas-in-oil and standard oil analysis for the Main Transformer, s/n 90-711, indicate the gas levels and insulating oil properties have remained relatively stable and are suitable for continued service. We recommend continued sampling as per your maintenance schedule.

4. The results of the furan analysis for the Main Transformer, s/n 90-711, conclude that the furan levels have remained relatively low. This indicates that the paper insulation is in acceptable condition and has not been subjected to heat stress during the period. No further action is required at this time.

5. The main access doors to the indoor substation were found without any warning signs posted. As per the Ontario Electrical Safety Code 36-006, we recommend installing a warning sign on each entrance door to this room as soon as possible.

6. The main access doors to the indoor substation were found with the door frame grounded but missing a corresponding jumper to the doors. As per the Ontario Electrical Code 36-308(1)(2)(a)(i) and Table 52, we recommend installing a ground jumper, as soon as possible, to ensure all metal, non-current carrying components are bonded to ground and maintain a tolerable level of step and touch potential.

7. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and Table 52, we recommend that a rubber switching mat be installed directly in front of the breaker cells, as soon as possible, in order to maintain a tolerable level of step and touch potential.

8. We recommend that a co-ordination study be completed involving all of the electrical equipment associated with the Montreal Street Substation. All of the protective relays were found to have discrepancies and a coordination study would determine if the values are correct or if these relays are in need of repair.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Montreal Street Substation

9. The insulation resistance of the phase 'B' cable for the Feeder #1 Circuit was found to have significantly deteriorated since November 2003. The insulation resistance is suitable for the voltage rating, however, we recommend monitoring the insulation resistance in September 2007 to ensure reliability of the service.

10. The contact pressure between the main current carrying contact components on phase 'C' of the breaker designated 'Feeder #2', s/n 1149, was found to be defective. There was evidence of surface pitting and possible arcing damage to the contact surfaces. This breaker was removed from service and the 'Spare' breaker, s/n 1152, was installed into the Feeder #2 cell. The trip coil on the 'Feeder #2' breaker, s/n 1152, was found defective during the 2003 preventative maintenance inspection and was exchanged, at this time, with the trip coil from the 'Spare' breaker, s/n 1149. We recommend replacing the moving and stationary contact components and the trip coil, as soon as possible, to maintain a functional spare breaker.

11. The insulation resistance of the phase 'C' cable for the Feeder #2 Circuit was found low for the voltage rating. We recommend replacing this cable, as soon as possible, to ensure reliability of the service.

12. The resistance of the tripping coil for the breaker designated 'Spare', s/n 1149, was found high. This increased resistance prohibits proper operation, therefore, we recommend replacing the coil, as soon as possible, to ensure a suitable spare breaker is available for use in an emergency situation.

RONDAR INC.

January 7, 2003

Midland Power Business Group
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**

Subject: **Preventive Maintenance @ Queen, Fourth and Montreal Street Substations**
Our Ref. C1213

Dear Sir:

We are enclosing the results of the maintenance carried out at the Queen, Fourth and Montreal Street substations on October 14, 2003, October 20, 2003, and November 10, 2003, respectively.

In general, the results of the tests and inspections indicate that the equipment is suitable for service, except as noted in the comments and recommendations.

If you have any questions or require further information, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown
Technical Service Representative

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Queen Street Substation

1. The barbed wire surrounding the outdoor substation was found broken. We recommend replacing the broken areas of barbed wire and trimming the surrounding tree growth, as soon as possible, to prevent further deterioration of the substation enclosure.

2. The fence fabric located in the northwest corner of the substation was found without a ground conductor woven through it. As per the Ontario Safety Code, we recommend a ground conductor be woven through the fence fabric, as soon as possible, with corresponding connections to the top rail to ensure all metal, non-current carrying components are bonded to ground.

3. The outdoor substation yard was found with excessive weed growth. As per the Ontario Electrical Safety Code 36-304(5), table 52, we recommend that the yard debris and weeds be removed and 50-75mm of 19mm crushed stone to be added, as soon as possible, to prevent the step and touch potential from exceeding acceptable tolerances.

4. The paint condition of the Main Transformer, s/n C-46206-1, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

5. The standard, dissolved gas-in-oil and furan analysis on the Main Transformer, s/n C-46206-1, could not be completed at the time of inspection due to poor weather and will be completed, as soon as possible, in conjunction with the high voltage bushing replacement.

6. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and table 52, we recommend that a rubber switching mat be installed, as soon as possible, directly in front of the breaker cells to maintain a tolerable level of step and touch potential.

7. Insulating oil was added to each of the four (4) oil circuit breakers, Circuit #1, s/n 37213, Circuit #2, s/n 37214, Circuit #3, s/n 37211, and Circuit #4, s/n 37212, to ensure an acceptable level is maintained and to allow for further sampling. We recommend continued monitoring of the oil level during your maintenance period.

8. The oil analysis completed of the four (4) indoor oil circuit breakers, Circuit #1, s/n 37213,
Circuit #2, s/n 37214, Circuit #3, s/n 37211, and Circuit #4, s/n 37212, indicates all oil properties are within normal operating limits and suitable for continued service.

9. As previously reported, the arcing contacts (stationary and moving) on the oil circuit breakers designated CCT#2, CCT#3 and CCT#4 were found to be deteriorated. However, the arcing contacts on the oil circuit breaker designated CCT#1 were found to be in very poor condition compared to the other breakers. We recommend that both the stationary and moving arcing contacts on the oil circuit breaker designated CCT#1, s/n 37213, be replaced, as soon as possible, to prevent a failure from occurring.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

1. The outdoor substation yard was found to have an excess of debris within it. We recommend that qualified personnel clean out this debris on a regular basis to ensure the dielectric properties of the yard.

2. The outdoor substation yard was found to have an excess of weeds growing within it. We recommend that an herbicide be applied annually to control this on-going problem and also to ensure the dielectric properties of the crushed stone.

3. The depth of the crushed stone in the outdoor substation yard was found to be low. As per the Ontario Electrical Safety Rule 36-304 (5), we recommend that 150mm of crushed stone be added to the substation yard, as soon as possible.

4. The fence enclosure was found damaged during our inspection. The top rail barbed wire holder was found broken and the corresponding middle rail was severely bent. We recommend that these problems be repaired, as soon as possible, to ensure that unauthorized personnel do not gain entry into this area.

5. It was found that both the main access gate and the man gate did not have corresponding bonds to ground. As per the Ontario Electrical Safety Code Rule 36-312 (3), we recommend that these grounds be installed, as soon as possible, to ensure that the touch potentials of this enclosure stay within acceptable limits.

6. The flexible braided shunts on the High Voltage Air Break Switch on the tower were found to be deteriorating as previously reported. However, the rate of deterioration is low and we recommend replacing these shunts during your next shutdown to prevent further breakdown and a potential failure.

7. The insulators of the High Voltage Air Break Switch on the top of the tower were found contaminated with a type of carbon spray from the arcing whips operation. Although this has not affected their insulation value, nor is it an immediate concern, it should be made note of since this problem will only get worse each time the switch is operated under potential. No further action is required at this time.

8. The stationary and moving contact surfaces on the 'B' phase primary fuse located on the tower were found to have severe pitting. The contact surfaces were repaired and left in satisfactory condition. We recommend monitoring the condition of these contacts to ensure a low resistance connection is maintained.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

9. It was noted that there is no Silica Gel Breather located on the Main Transformer, s/n 280019. As the temperature and load increases and decreases for this transformer, the oil level rises and falls creating a breathing effect. As the transformer breathes, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

10. Evidence of tracking was found on the H2 and H3 high voltage bushings for the Main Transformer, s/n 280019. Although the insulation resistance value of the primary windings and bushings indicate that this has not yet affected their insulation, the integrity of the bushings is questionable. We recommend inspecting and further testing of these bushings in six (6) months in an attempt to determine the severity of the problem and their reliability. From this investigation, a corrective course of action, if necessary, can be developed.

11. It was noticed that oil was leaking around both of the sample valves at the bottom of the tank on the Main Transformer, s/n 280019. We recommend that this problem be monitored, on an annual basis, to determine what corrective action, if any, is required.

12. The paint condition of the Main Transformer, s/n 280019, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

13. The concrete pad of the Main Transformer was found to be sitting at an angle possibly affecting its cooling properties. We recommend replacing the transformer pad, as soon as possible, to ensure that the transformer operates as designed.

14. The results of the standard analysis of the insulating fluid in the Main Transformer, s/n 280019, showed that the Neutralization Number is merely fair, indicating that there is some oxidization occurring in the oil. As well, the Interfacial Tension indicates that there are polar contaminates and oxidation products in the oil. Although these issues are not severe at this time, they do warrant noting. We recommend including an oxidation inhibitor analysis during your next substation maintenance to monitor the level of inhibitor in the insulating fluid.

15. The results of the furan analysis on the Main Transformer, s/n 280019, indicate that the level of furans has remained relatively stable since June 2003 indicating that the paper insulation has not undergone heat stress during this period. However, present levels indicate that the insulation has undergone moderate deterioration. We recommend continuing to sample for furans during your substation maintenance work to monitor the condition of the paper insulation.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

16. The results of the dissolved gas-in-oil analysis on the Main Transformer, s/n 280019, indicate that the level of carbon monoxide has increased since June 2003 with the furan analysis indicating that the level is due to heat stress in the paper insulation. We recommend resampling in May 2004 to continue monitoring the level of these gases.

17. We were unable to locate a warning sign on the entrance door to the indoor substation room. As per the Ontario Electrical Safety Code Rule 36-006 (1)(a), we recommend that a sign be affixed, as soon as possible, to warn unqualified personnel of the potential hazard present in this room.

18. The entrance door to the indoor substation room was found to be missing a ground connection to a corresponding ground bus in this room. We recommend installing a ground bus in this room and bonding the door to ground, as soon as possible, to ensure that all non-current carrying components are bonded to ground.

19. The end cabinet of the indoor switchgear was found to be full of old equipment. We recommend that this debris be cleared out of this cell to ensure that no extra equipment can be damaged or create extra hazard during an emergency situation.

20. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and table 52, we recommend that a rubber switching mat be installed, as soon as possible, directly in front of the breaker cells to maintain a tolerable level of step and touch potential.

21. We recommend that a co-ordination study be completed involving all of the electrical equipment associated with the Fourth Street Substation. All of the protective relays were found to have discrepancies and we recommend verifying with the coordination study to determine if the values are correct or if these relays are in need of repair.

22. The standard oil and water analysis for the Feeder #2 oil circuit breaker, s/n 39697, concluded that the insulating properties of the fluid are within normal operating limits and we recommend sampling as per your maintenance schedule.

23. The White phase overcurrent relay protecting the Feeder #2 breaker, s/n 39697, was found with the pick-up function exceeding recommended limits. An attempt was made to adjust and repair the relay but to no avail. Two (2) relays provided by Mid-Ontario Energy Services were used to replace the White & Red phase relays and were set as requested with the instantaneous settings adjusted from 55 to 30. The test results indicate the relays are suitable for service and were put into service on November 10, 2003. We recommend completing a co-ordination study to prevent any unnecessary nuisance tripping.

COMMENTS AND RECOMMENDATIONS

Fourth Street Substation

24. The insulation resistance of the 5kV cables for the Feeder #2 circuit were found at an unacceptable level for continued service. We recommend replacing the cables, as soon as possible, to ensure the reliability of the service.

25. The standard oil and water analysis for the Feeder # 3 oil circuit breaker, s/n 39695, concluded that the insulating properties of the fluid are within normal operating limits and we recommend sampling as per your maintenance schedule.

26. The standard oil and water analysis for the Feeder # 4 oil circuit breaker, s/n 39696, concluded that the insulating properties of the fluid are within normal operating limits and we recommend sampling as per your maintenance schedule.

27. The insulation resistance of the phase 'A' 5kV cable for the Feeder #4 circuit was found at an unacceptable level for continued service. Further investigation determined that the low insulation resistance was not related to the terminations and that the cable was defective. We recommend replacing this cable, as soon as possible, to ensure the reliability of the service.

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COMMENTS AND RECOMMENDATIONS

Montreal Street Substation

1. During the 2001 preventative maintenance, a sticky residue was found coating the insulators on the tower and the source was believed to be the surrounding trees. The condition of these insulators during the 2003 preventative maintenance has not worsened and we continue to recommend monitoring the tree growth and trimming the branches surrounding the substation as deemed necessary.

2. The weed growth in the main outdoor substation was found to be suitable and we recommend applying an herbicide in April/May 2004 to prevent any new weed growth.

3. The sample valve located close to the bottom of the tank for the Main Transformer, s/n 90-711, located in the outdoor substation, was found with a small amount of oil residue around the valve and fittings. However, there was no presence of fresh oil on the ground and we recommend monitoring this oil leak to determine if further action is required.

4. The results of the dissolved gas-in-oil and standard oil analysis for the Main Transformer, s/n 90-711, indicate the gas levels and insulating oil properties have remained relatively stable and are suitable for continued service. We recommend continued sampling as per your maintenance schedule.

5. The results of the furan analysis for the Main Transformer, s/n 90-711, indicate the paper insulation is in acceptable condition and has not been subjected to heat stress. At this time, no further action is required.

6. The main access doors to the indoor substation were found without any warning signs posted. As per the Ontario Electrical Safety Code 36-006, we recommend installing a warning sign on each entrance door to this room, as soon as possible.

7. The main access doors to the indoor substation were found with the door frame grounded but missing a corresponding jumper to the doors. As per the Ontario Electrical Code 36-308(1)(2)(a)(i) and table 52, we recommend installing a ground jumper to ensure all metal non-current, carrying components are bonded to ground and to maintain a tolerable level of step and touch potential.

8. As previously reported in 2001, the rear compartments of the indoor switchgear were inspected for moisture with a minimal amount found in the cable pit. We recommend continuing to monitor these compartments for moisture on a regular basis to prevent deterioration of the equipment.

COMMENTS AND RECOMMENDATIONS

Montreal Street Substation

9. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306 and table 52, we recommend that a rubber switching mat be installed, as soon as possible, directly in front of the breaker cells to maintain a tolerable level of step and touch potential.

10. We recommend that a co-ordination study be completed involving all of the electrical equipment associated with the Montreal Street Substation. All of the protective relays were found to have discrepancies and we recommend verifying with the coordination study to determine if the values are correct or if these relays are in need of repair.

11. The resistance of the tripping coil for the breaker designated Spare, s/n 1152, was found high. This increased resistance prohibits proper operation and we recommend replacing the coil, as soon as possible, to ensure a suitable spare breaker is available for use in an emergency situation.

12. During re-energization it was found that the coil located in the electrical control cell for the breaker designated Feeder #3, s/n 1150, was defective. The problem was repaired and left in satisfactory condition. A similar problem was reported during the 1999 substation maintenance; therefore, we recommend upgrading the coils located in each of the feeder breaker electrical control cells to prevent further complications and unnecessary downtime.

13. The insulation resistance of the phase 'C' cable for the Feeder #2 circuit was found low for the voltage rating. We recommend replacing this cable, as soon as possible, to ensure reliability of the service.

RONDAR INC.

Section 8

2004 & 2002 MAINTENANCE REPORTS
Brandon, Dorion & Scott Street Substations

RONDAR INC.

January 11, 2005

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**

Subject: **2004 Preventative Maintenance @ Brandon Street Substation**
Our Ref. C1399

Dear Sir,

We are enclosing the results of the maintenance work carried out at your Brandon Street Substation on October 12, 2004.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

The furan analysis completed on each of the single phase transformers 'A', s/n 213274, 'B', s/n 213273, and 'C', s/n 213275, conclude that the paper insulation in each transformer has undergone extensive deterioration, probably caused by thermal heating, and are in very poor condition. Based on results from previous years, the maximum temperature of these transformers has been 60°C which is a relatively high operating temperature and over the 48 years of service, 1956-2004, thermal heating has caused the insulation to deteriorate. Due to these high levels of furans, we recommend to budget for the replacement of these three (3) single phase transformers within the next year and to consider upgrading the total capacity of this station due to the higher operating temperature.

Rondar Inc. would be interested to work with Mid-Ontario Energy Services Inc. in any capacity to develop and/or implement a solution for this station.

If you have any questions or require further information, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown
Technical Service Representative

20 Venture Drive, Unit #9, Scarborough, Ontario M1B 3R7
Tel: (416) 286-2444 Fax: (416) 286-2445 E-mail: dbrown@rondar.com

COMMENTS AND RECOMMENDATIONS

Outdoor Substation and Tower

1. The substation yard was found to have an excess of weeds growing within it. We recommend that an herbicide be applied annually to control this on-going problem and ensure the dielectric properties of the crushed stone.

2. As found previously during the 2002 preventative maintenance and confirmed this year, the high voltage air break switch on the tower structure was found to have a defective arc interrupter with a very high resistance on the load side of phase 'B'. We recommend that this interrupter be changed during your next substation maintenance.

3. It was noted that there are no silica gel breathers installed on any of the oil filled transformers located in this substation. As the temperature and load increases and decreases for these transformers, the oil level rises and falls respectively creating a breathing effect. As the transformers breathe, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing silica gel breathers on these transformers, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase 'A' Transformer, s/n 213274

1. As found during previous inspections, the oil level for this transformer is slightly low but has not worsened since October 2004. We recommend periodic monitoring to ensure this level does not diminish further thereby affecting the service reliability.

2. A small crack was found on the porcelain of the secondary neutral bushing of this transformer. The crack was inspected and found not to have worsened since the 2002 preventative maintenance. We recommend monitoring the condition of this bushing to ensure the insulation integrity does not deteriorate thereby affecting the reliability of the equipment. Additionally, we recommend completing a 'hot' collar test on the bushing during your next substation maintenance to further assess the condition of the unit.

3. As found during previous inspections, a small oil leak was present around the base gasket of the secondary neutral bushing. The amount of fresh oil found during this years maintenance around the gasket indicates that this leak has not further developed. We recommend this leak be monitored and repaired when deemed necessary.

4. The paint condition of this transformer was found to be deteriorating thereby allowing rust to develop. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

5. The results of the standard and water content analysis conclude that insulation properties of the insulating fluid are within normal operating ranges. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties. Furthermore, based on the age of the oil, we recommend adding inhibitor analysis to your sampling in October 2005.

6. The results of the furan analysis on this transformer indicate that the paper insulation has undergone extensive deterioration and has an actual level of 1,344 parts per billion, accounting for the retrofil in November 2000. The level of furans have increased gradually and is expected as the age of a transformer increases. Due to these high levels of furans, we recommend to budget for the replacement of this transformer within the coming year.

7. The results of the dissolved gas-in-oil analysis indicate that the levels of carbon monoxide and carbon dioxide have increased since October 2002. The results from the furan analysis conclude that these levels are due to deterioration of the paper insulation. We recommend continued sampling in October 2005 to continue monitoring the level of these gases.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase 'B' Transformer, s/n 213273

1. As found during previous inspections, the oil level of this transformer is slightly low but not worsened since October 2004. We recommend periodic monitoring to ensure this level does not diminish further thereby affecting the service reliability.

2. The porcelain of the secondary neutral bushing of this transformer was found to be cracked and was sealed at the time of inspection. We recommend replacing this bushing, at your earliest convenience, to ensure the insulation integrity of the equipment and service continuity.

3. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

4. The results of the standard and water content analysis conclude that insulation properties of the insulating fluid are within normal operating range. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties. Furthermore, based on the age of the oil, we recommend adding inhibitor analysis to your sampling in October 2005.

5. The results of the furan analysis on this transformer indicate that the paper insulation has undergone extensive deterioration and has an actual level of 1,144 parts per billion, accounting for the retrofil in November 2000. The level of furans have increased gradually and is expected as the age of a transformer increases. Due to the high level of furans, we recommend to budget for the replacement of this transformer within the coming year.

6. The results of the dissolved gas-in-oil analysis indicate that the level of hydrogen has increased since October 2002 indicating the presence of corona, possibly involving the paper insulation. Rate of rise of the total combustible gas content indicates that the fault is not severe at this time, while all other fault gases have remained within normal range. We recommend resampling in January 2005 to continue monitoring the level of these gases.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase 'C' Transformer, s/n 213275

1. As found during previous inspections, the oil level of this transformer is slightly low but has not worsened since October 2004. We recommend periodic monitoring to ensure this level does not diminish further thereby affecting the service reliability.

2. One of the primary bushings for this transformer was found with a chip out of the porcelain. The chip was sealed with Glyptal at the time of maintenance and left in adequate condition. We recommend monitoring the insulation integrity of this bushing during the 2006 preventative maintenance.

3. The X1 secondary bushing of this transformer was found to be cracked. The crack was sealed with a conformal coating lacquer at the time of maintenance and was left in adequate condition. We recommend that this crack be monitored and that the bushing be replaced, when deemed necessary.

4. The inspection cover of this transformer was found to be slightly leaking oil. As previously reported in 2002, we recommend that this leak be periodically monitored to ensure that this leak does not further develop.

5. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

6. The results of the standard and water content analysis conclude that insulation properties of the insulating fluid are within normal operating ranges. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties. Furthermore, based on the age of the oil, we recommend adding inhibitor analysis to your sampling in October 2005.

7. The results of the furan analysis on this transformer indicate that the paper insulation has undergone extensive deterioration and has an actual level of 1,145 parts per billion, accounting for the retrofil in November 2000. The level of furans have been gradually increasing and is expected as the age of a transformer increases. Due to the high level of furans, we recommend to budget for the replacement of this transformer within the coming year.

8. The results of the dissolved gas-in-oil analysis indicate that the levels of carbon monoxide and carbon dioxide have increased since October 2002. The results from the furan analysis conclude that these levels are due to deterioration of the paper insulation. We recommend continued sampling in October 2005 to continue monitoring the level of these gases.

COMMENTS AND RECOMMENDATIONS

Outdoor Spare Transformer, s/n 213272

1. We were unable to perform any electrical tests on this transformer as there were no bushings and thereby, no corresponding external electrical connections.

2. The gaskets on all bushing ports along with the tapchanger were found to be leaking oil. We recommend that these gaskets be replaced to maintain a suitable spare transformer.

3. The oil level gauge on this transformer was found to have been previously removed and as a result, the oil level is unknown. We recommend that this gauge be replaced to maintain a fully equipped spare transformer should you require these components for the future.

4. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

5. The results of the standard and water content analysis conclude that insulation properties of the insulating fluid are within normal operating ranges. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties. Furthermore, based on the age of the oil, we recommend adding inhibitor analysis to your sampling in October 2005.

6. The results of the furan analysis on this transformer indicate that the paper insulation has undergone extensive deterioration and has an actual level of 357 parts per billion, accounting for the retrofil in November 2000. The level of furans have been gradually increasing and is expected as the age of a transformer increases. Due to the high level of furans, we recommend that this transformer not be placed into service.

7. The results of the dissolved gas-in-oil analysis indicate that the levels of carbon monoxide and carbon dioxide have increased. The results from the furan analysis conclude that these levels are due to deterioration of the paper insulation. We recommend continued sampling in October 2005 to continue monitoring the level of these gases.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

1. It was found that the floor and wall paint within the indoor substation room were in poor condition. We recommend that the floor and walls be painted, as soon as possible, in order to minimize the dust within this room.

2. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306, we recommend that a rubber switching mat be installed, at your earliest convenience, to maintain adequate dielectric properties for personnel during switching operations.

3. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a device be installed and wired to an alarm panel as soon as possible.

4. The results of standard oil analysis of the insulating oil for Main Oil Circuit Breaker, s/n 633363P1, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

5. The time-delay operation of the phase 'B' protection relay for the Main Oil Circuit Breaker, s/n 633363P1, is operating lower than the manufacturer's recommended limits. At the time of maintenance, adjustments were attempted to increase the time delay, however, further investigation is required to determine if the relay should be replaced or if repairs can be made.

6. The resistance of the phase 'A' contacts for the Feeder Breaker #1, s/n 633363P7, have increased and warrant further internal investigation. We recommend inspecting the internal contacts, at your earliest convenience, to determine the source of the increased resistance.

7. The results of standard oil analysis of the insulating oil for Feeder Breaker #1, s/n 633363P7, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

8. The results of standard oil analysis of the insulating oil for Feeder Breaker #2, s/n 633363P3, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

9. The results of standard oil analysis of the insulating oil for Bus Tie Breaker, s/n 633363P5, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

10. Based on the insulation resistance test result of the phase 'A' power cable for the Feeder #2 circuit, the condition of the insulation with respect to ground is lower when compared to the other cables, however, the cable is suitable for continued service at this time. We recommend monitoring the insulation resistance value during your 2006 preventative maintenance inspection.

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RONDAR INC.

January 17, 2005

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**

Subject: **2004 Preventative Maintenance @ Dorion Street Substation**
Our Ref. C1399

Dear Sir,

We are enclosing the results of the maintenance work carried out at your Dorion Street Substation on October 13, 2004.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

If you have any questions or require further information, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown
Technical Service Representative

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Substation

1. The insulation resistance of the three (3) lightning arresters located on the substation tower indicates that the surge protection operation has internally faulted and replacement is required. As well, the rating of the existing lightning arresters does not meet current standards for equipment protection. We recommend replacing and upgrading the three (3) lightning arresters, as soon as possible, to meet current surge protection requirements.

2. We were unable to locate a complete set of spare fuse links for the primary protection fuses for the Main Transformer. We recommend verifying that one (1) complete set of fuses is available for use in an emergency situation.

3. It was noted that there was no silica gel breather installed on the Main Transformer, s/n 238691. As the temperature and load increases and decreases for this transformer, the oil level rises and falls creating a breathing effect. As the transformer breathes, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

4. The Main Transformer, s/n 238691, was found to have minor oil leaks around the level gauge on the conservator tank and around the valve between the conservator and main tank. We recommend that these leaks be monitored for severity and repaired during your next substation maintenance, if deemed necessary.

5. A large chip out of the H3 primary bushing was found on the Main Transformer, s/n 238691. This chip was sealed with an insulating glyptal paint at the time of maintenance and was left in satisfactory condition. We recommend continued monitoring during your preventative maintenance schedule to ensure the insulation integrity does not deteriorate.

6. The paint condition of the Main Transformer, s/n 238691, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

7. The results of the standard and water content analysis conclude that insulation properties of the insulating fluid are within normal operating ranges. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Substation

8. The results of the dissolved gas-in-oil analysis indicate that the level of acetylene has decreased and in a breathing transformer this indicates that the gas is either being produced at a very low rate or no longer being produced. Our concern is that acetylene has been produced in the past and involves arcing between an energized component and ground. We recommend resampling in April 2005 to ensure that if acetylene again starts to be produced, a corrective course of action can be developed prior to equipment failure.

9. The results of the furan analysis on this transformer indicate that the paper insulation has not undergone any heat stress since October 2002. With respect to the age of the Main Transformer, s/n 238691, we recommend completing annual furan analysis to allow for accurate trending of the condition of the paper insulation. This information will assist Rondar in reporting and determining a time frame when this transformer should be removed from service.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

1. The entrance doors to the indoor substation room were found to not have any warning signs. As per the Ontario Electrical Code Rule 36-006(1)(a), we recommend that warning signs be installed as soon as possible in order to inform unauthorized personnel of the hazard present in this room.

2. The floor and wall paint within the indoor substation room were found to be in poor condition. We recommend that the floor and walls be repainted, as soon as possible, in order to minimize the dust within this room.

3. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a smoke detection device be installed and wired to an alarm panel as soon as possible.

4. The results of standard oil analysis of the insulating oil for Feeder Breaker #1, s/n 56068, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

5. The results of standard oil analysis of the insulating oil for Feeder Breaker #2, s/n 56067, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

RONDAR INC.

January 17, 2005

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**

Subject: **2004 Preventative Maintenance @ Scott Street Substation**
Our Ref. C1399

Dear Sir,

We are enclosing the results of the maintenance work carried out at your Scott Street Substation on October 26, 2004.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

If you have any questions or require further information, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown
Technical Service Representative

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Substation

1. The substation yard was found to have an excess of debris within it. We recommend that qualified personnel clean out this debris on a regular basis to ensure the dielectric properties of the yard are maintained.

2. The fence fabric for the substation enclosure was found to not have a ground conductor woven through it. As per the Ontario Electrical Safety Code Rule 36-312(4), we recommend that a ground conductor be woven through the fence fabric in at least two places at your earliest convenience to ensure all metallic, non-current carrying components are bonded to ground.

3. The operating handle for the high voltage switch located on the substation tower was found without a direct connection to the ground grid. As per the Ontario Electrical Safety Code 36-310, we recommend installing a flexible jumper to the operating handle, as soon as possible, to ensure the safety of personnel during switching operations.

4. The high voltage switch on the substation tower does not have a metallic gradient control mat (switching mat). As per the Ontario Electrical Safety Code Rule 36-301(2)(a), we recommend that a switching mat be installed, as soon as possible, in order to maintain touch voltages at tolerable levels, as outlined in Table 52 of the Ontario Electrical Safety Book, at the location where the switch operator is normally standing.

5. The ratings of the three (3) lightning arresters located on the substation tower do not meet current standards. We recommend upgrading the three (3) lightning arresters, at your earliest convenience, to prevent equipment damage due to line surges.

6. A silica gel breather is not located on transformer, s/n 1-1028. As the temperature and load increases and decreases, the oil level rises and falls respectively creating a breathing effect. As the transformer breathes, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

7. A burn mark along with a melted splash mark were found on the top metal globe of the phase 'B' primary bushing on the main transformer, s/n 1-1028, due to a flashover that has occurred in the past. Although these marks do not seem to affect the electrical properties of the transformer, it should be monitored during future inspections.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Substation

8. Two (2) oil leaks were found on the main transformer, s/n 1-1028. One leak was noticed on the transformer end of the conservator piping while the second leak was found at the tap changer handle. We recommend that these leaks be monitored to determine their severity and to determine if corrective action is required.

9. The paint condition of the main transformer, s/n 1-1028, was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

10. The main outdoor transformer, s/n 1-1028, was found bonded to the ground grid by the use of only one (1) ground connection. As per the Ontario Electrical Safety Code Rule 36-308(e)(iii), we recommend installing a second ground connection between the ground grid and the main frame of the transformer, as soon as possible, to ensure redundant ground protection in a fault condition.

11. The results of the standard and water content analysis completed on the insulating fluid in the main transformer, s/n 1-1028, conclude that insulation properties of the insulating fluid are within normal operating ranges. We recommend continued standard and water content sampling in October 2005 to allow further trending of the oil properties.

12. The results of the furan analysis on the main transformer, s/n 1-1028, indicate that the paper insulation has undergone extensive deterioration but has remained within 10% of the previous result obtained in June 2003. This indicates that during this time period the insulation has not been subjected to heat stress, however, our test results do not account for the retro-filling of this transformer (believed to have been completed between 1994 and 1997), therefore, the actual level could be significantly higher. The furan trending chart shows that the levels have steadily increased since October 1999. With respect to the age of this transformer, we recommend to budget for the replacement and upgrading of this transformer within the next two (2) years.

13. The results of the dissolved gas-in-oil analysis completed on the main outdoor transformer, s/n 1-1028, indicate that the gas concentrations have remained within normal ranges and are suitable for continued service. We recommend continued dissolved gas-in-oil sampling in October 2005 to continue monitoring the level of these gases.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

1. We were unable to locate a warning sign on the entrance door to the indoor substation room. As per the Ontario Electrical Safety Code Rule 36-006 (1)(a), we recommend that a sign be affixed, as soon as possible, to warn unqualified personnel of the potential hazard present.

2. As previously reported in our 1999 Preventative Maintenance report, the entrance door of the indoor substation was found to be missing a ground connection to a corresponding ground bus. We recommend installing a ground bus in this room and bonding the door to ground, as soon as possible, to ensure that all metallic, non-current carrying components are bonded to ground.

3. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306, we recommend that a rubber switching mat be installed, at your earliest convenience, to maintain adequate dielectric properties for personnel during switching operations.

4. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a device be installed and wired to an alarm panel as soon as possible.

5. We were unable to locate any warning signs on the switchgear located in this room. As per the Ontario Electrical Safety Code Rule 36-006(1)(a), a warning sign should be installed at your earliest convenience.

6. The results of the standard oil analysis of the insulating oil in Feeder Breaker #1, s/n 53315, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

7. The results of the standard oil analysis of the insulating oil in Feeder Breaker #2, s/n 53317, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

8. The results of the standard oil analysis of the insulating oil in Feeder Breaker #3, s/n 56069, indicate that the oil properties are within normal operating ranges and suitable for continued service. We recommend completing a standard sample during your 2006 preventative maintenance inspection.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

9. The time delay test results for the overcurrent relays protecting the breakers designated Feeder #1, s/n 53315, Feeder #2, s/n 53317, and Feeder #3, s/n 56069, were found exceeding the manufacture limits. We recommend verifying the correct setting and calibrating the time delay function on these relays, as soon as possible, to function as per the time dial setting.

RONDAR INC.

November 18, 2002

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Erik Kussen**

Subject: **2002 Preventative Maintenance @ Brandon Street Substation**
Our Ref. C1011

Dear Sir,

We are enclosing the results of the maintenance work carried out at the Brandon Street Substation on October 3, 2002.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

If you have any questions, or require further information, please do not hesitate to contact our office.

RONDAR INC.

Ian Dobson
Technical Service Representative

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Substation and Tower

1. The warning signs that were installed on the substation fence were in satisfactory condition, however, it was noted that there are not enough warning signs for the size of the enclosure. For an enclosure of this size, we recommend installing one (1) warning sign for every three spans of fence.

2. The substation yard was found to have an excess of weeds growing within it. We recommend that an herbicide be applied annually to control this on-going problem and to ensure the dielectric properties of the crushed stone.

3. The high voltage air break switch on the tower structure was found to have a defective arc interrupter with a very high resistance on the load side of phase B. We recommend that this interrupter be changed during your next substation maintenance.

4. The line side clip of the phase A high voltage fuse holder on the tower structure was found to be defective. Since this type of fuse clip is meant to release the fuse holder when the fuse link clears a fault, this component was replaced with a spare clip found in the substation and was left in satisfactory condition.

5. It was noted that there are no silica gel breathers installed on any of the oil filled transformers located in this substation. As the temperature and load increases and decreases for these transformers, the oil level rises and falls respectively creating a breathing effect. As the transformers breath, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing silica gel breathers on these transformers, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase A Transformer, s/n 213274

1. The oil level of this transformer was found to be low. We recommend that this level be topped up during your next substation maintenance.

2. The porcelain of the secondary neutral bushing of this transformer was found to have a small crack. At this time, the crack was sealed with a conformal coating lacquer and the bushing was left in adequate condition. We recommend that this crack be monitored to determine if the bushing needs to be replaced.

3. The secondary neutral bushing of this transformer was found to have an oil leak at its gasket. We recommend that this leak be monitored and repaired, if necessary.

4. The two top ports of this transformer were found to be leaking oil. We recommend that these leaks be monitored and repaired, if necessary.

5. The paint condition of this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

6. The results of the furan analysis on this transformer indicate that the paper insulation has undergone some heat stress since June 2001. We recommend resampling this transformer in April 2003 to continue to monitor the condition of the paper insulation.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase B Transformer, s/n 213273

1. The oil level of this transformer was found to be slightly low. We recommend that this level be topped up during your next substation maintenance.

2. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

3. The results of the furan analysis on this transformer indicate that the paper insulation has undergone some heat stress since June 2001. We recommend resampling this transformer in April 2003 to continue to monitor the condition of the paper insulation.

4. The results of the dissolved gas-in-oil analysis indicate that the level of hydrogen has increased since July 2001 indicating the presence of corona. Total combustible gas content indicates that the fault is moderately severe at this time, while all other fault gases have remained within normal range. We recommend resampling in January 2003 to continue monitoring the level of these gases.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Phase C Transformer, s/n 213275

1. The oil level of this transformer was found to be slightly low. We recommend that this level be topped up during your next substation maintenance.

2. One of the primary bushings for this transformer was found to have a chip out of the porcelain. At this time, the chip was sealed with a conformal coating lacquer and was left in adequate condition.

3. The X1 secondary bushing on this transformer was found to have a crack. At this time, the crack was sealed with a conformal coating lacquer and the bushing was left in adequate condition. We recommend that this crack be monitored and that the bushing be replaced, if necessary.

4. The top port of this transformer was found to be leaking oil. We recommend that this leak be monitored and repaired, if necessary.

5. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

6. The results of the furan analysis on this transformer indicate that the paper insulation has undergone some heat stress since June 2001. We recommend resampling this transformer in April 2003 to continue to monitor the condition of the paper insulation.

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RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Spare Transformer, s/n 213272

1. We were unable to perform any electrical tests on this transformer as there were no bushings and thereby, no corresponding external electrical connections.

2. The gaskets on all bushing ports along with the tapchanger were found to be leaking oil. We recommend that these gaskets be replaced to maintain a properly working spare transformer.

3. The oil level gauge on this transformer was found to have been previously removed. As a result, the oil level is unknown. We recommend that this gauge be replaced to maintain a fully equipped spare transformer should you require these components again in the future.

4. The paint condition for this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

1. We were unable to locate a rubber switching mat for the indoor switchgear. As per the Ontario Electrical Safety Code 2-306, we recommend that a rubber switching mat be installed, at your earliest convenience, to maintain adequate dielectric properties for personnel during switching operations.

2. It was found that the floor and wall paint within the indoor substation room were in poor condition. We recommend that the floor and walls be repainted, as soon as possible, in order to minimize the dust within this room.

3. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a device be installed and wired to an alarm panel, as soon as possible.

4. We recommend that a coordination study be completed involving all of the electrical equipment associated with the Brandon Street Substation, as soon as possible. All of the protective relays were found to have discrepancies and we recommend verifying with the coordination study to determine if the values obtained are correct or if these relays are in need of repair.

5. The dielectric breakdown for the Main Oil Circuit Breaker, s/n 633363P1, was found to be low for its high voltage rating. We recommend resampling this breaker, immediately, to verify these results.

RONDAR INC.

November 18, 2002

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Erik Kussen**

Subject: **2002 Preventative Maintenance @ Dorion Street Substation**
Our Ref. C1011

Dear Sir,

We are enclosing the results of the maintenance work carried out at the Dorion Street Substation on October 2, 2002.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

If you have any questions, or require further information, please do not hesitate to contact our office.

RONDAR INC.

Ian Dobson
Technical Service Representative

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Outdoor Yard, Transformer and Tower

1. The barbed wire on the fence in the main outdoor yard that had been reported as loose in our 2000 Preventative Maintenance Report was repaired, by Rondar personnel, during this years maintenance and was left in a satisfactory condition.

2. The outdoor substation yard was found to have an excess of weeds growing within it. We recommend that an herbicide be applied annually to control this on-going problem and also to ensure the dielectric properties of the crushed stone.

3. The depth of crushed stone depth in the outdoor substation yard was found to be thin in some areas. For the moment, the depth of stone is acceptable, however, we recommend considering the need to top up the depth of the crushed stone at some point in the future.

4. We were unable to locate spare fuse links for the high voltage primary protection fuses on the tower structure in the outdoor substation. We recommend that a set of three (3) spare fuse links be purchased, at your earliest convenience, for use in an emergency situation.

5. It was noted that there is no Silica Gel Breather located on the Main Transformer, s/n 238691. As the temperature and load increases and decreases for this transformer, the oil level rises and falls creating a breathing effect. As the transformer breathes, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

6. The Main Transformer, s/n 238691, was found to have an oil leak around the level gauge on the conservator tank. We recommend that this leak be monitored for severity and repaired during your next substation maintenance, if necessary.

7. A large chip was found out of the H3 primary bushing on the Main Transformer, s/n 238691. At this time, the chip was sealed with an insulating lacquer that will ensure moisture does not seep into the porcelain and the bushing was left in satisfactory condition.

COMMENTS AND RECOMMENDATIONS

Outdoor Yard, Transformer and Tower

8. The paint condition of the Main Transformer, s/n 238691, is deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

9. The results of the standard analysis of the insulating oil for the Main Transformer, s/n 238691, indicated that the dielectric breakdown is low for the high voltage rating. We recommend resampling this transformer, immediately, to verify these results.

10. The results of the dissolved gas-in-oil analysis on the Main Transformer, s/n 238691, showed an increase in acetylene since October 2001. This level is still not severe at this time, however, it seems to be slowly increasing at a rate of <1PPM/day. We recommend that an internal inspection of this transformer be completed if these gas levels continue to rise. We also recommend that resampling in April 2003 to continue monitoring the level of these gases.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Indoor Substation

1. It was found that the indoor substation room entrance doors do not have any warning signs. As per the Ontario Electrical Code Rule 36-006(1)(a), we recommend that warning signs be installed, as soon as possible, to inform unauthorized personnel of the hazard present in this room.

2. The indoor substation room was found to have no ground bus installed and no corresponding ground connection to the room door. We recommend installing a ground bus and door ground, as soon as possible, to comply with the Ontario Electrical Safety Code Rule 36-308 (1), to ensure that all metal, non-current carrying components are bonded to ground.

3. We were unable to locate a rubber switching mat for the indoor switchgear. We recommend that a rubber switching mat be installed, at your earliest convenience, to maintain adequate dielectric properties for personnel during switching operations.

4. It was found that the floor and wall paint within the indoor substation room were in poor condition. We recommend that the floor and walls be repainted, as soon as possible, in order to minimize the dust within this room.

5. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a smoke detection device be installed and wired to an alarm panel, as soon as possible.

6. We recommend that a co-ordination study be completed involving all of the electrical equipment associated with the Dorion Street Substation. The protective relay for Feeder #2 was found to have discrepancies and we recommend verifying with the coordination study to determine if the values are correct or if this relay is in need of repair.

20 Venture Drive, Unit 9, Scarborough, Ontario M1B 3R
Tel: (416)286-2444 Fax: (416)286-2445 E-mail: rondarto@look.ca

RONDAR INC.

November 29, 2002

Mid-Ontario Energy Services Inc.
16984 Hwy #12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Erik Kussen**

Subject: **2002 Preventative Maintenance @ Scott Street Substation**
Our Ref. C1011

Dear Sir,

We are enclosing the results of the maintenance work carried out at the Scott Street Substation on October 4, 2002.

In general, the results of the tests and inspections indicate that the equipment is suitable for service except as noted in our comments and recommendations section.

If you have any questions, or require further information, please do not hesitate to contact our office.

RONDAR INC.

Ian Dobson
Technical Service Representative

20 Venture Drive, Unit #9, Scarborough, Ontario M1B 3R7
Tel: (416) 286-2444 Fax: (416) 286-2445 E-mail: rondarto@look.ca

COMMENTS AND RECOMMENDATIONS

Outdoor Substation Yard and Tower

1. The outdoor substation yard was found to have an excess of debris within it. We recommend that qualified personnel clean out this debris on a regular basis to ensure the dielectric properties of the yard.

2. The fence fabric of the main fence enclosure was found to not have a ground conductor woven through it. As per the Ontario Electrical Safety Code Rule 36-312(4), we recommend that a ground conductor be woven through the fabric in at least two places at your earliest convenience.

3. The High Voltage Air Break Switch feeding the main outdoor tower does not have a metallic gradient control mat, (switching mat). As per the Ontario Electrical Safety Code Rule 36-301(2)(a), we recommend that a switching mat be installed as soon as possible, to maintain touch voltages at the tolerable levels as outlined in Table 52, of the Ontario Electrical Safety Book, at the location where the switch operator is normally standing.

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Main Transformer, s/n 1-1028

1. It was noted that there is no Silica Gel Breathers located on this transformer. As the temperature and load increases and decreases for this transformer, the oil level rises and falls creating a breathing effect. As the transformer breathes, the possibility of moisture contaminating the insulating fluid is likely. Therefore, we recommend installing a silica gel breather on this transformer, at your earliest convenience, to help prevent the insulating fluid from absorbing moisture.

2. A burn mark was noticed on the porcelain along with a melted splash mark on the top metal globe of the phase B primary bushing from a flashover that has occurred in the past. Although these marks did not seem to affect the electrical properties of the transformer, it should be noted for future inspections.

3. Two (2) oil leaks were found on this transformer. One leak was noticed on the transformer end of a pipe that feeds from the conservator tank down to the main transformer casing while the other leak was found at the tap changer handle. We recommend that these leaks be monitored to determine their severity, and if corrective action is required.

4. The paint condition of this transformer was found to be deteriorating. We recommend that this transformer be sandblasted and repainted, at your earliest convenience, to ensure that the transformer casing remains in satisfactory condition.

5. The results of the furan analysis indicate that the level of furans have increased since September 2000, meaning that this transformer has undergone heat stress during this period with a rate of increase of <1 ppb/day. We recommend resampling this transformer for furans in April 2003 to continue to monitor the condition of the paper insulation.

20 Venture Drive, Unit 9, Scarborough, Ontario M1B 3R7
Tel: (416)286-2444 Fax: (416)286-2445 E-mail: rondarto@look.ca

RONDAR INC.

COMMENTS AND RECOMMENDATIONS

Main Indoor Substation

1. We were unable to locate a warning sign on the entrance door to the indoor substation room, as previously reported in our 1999 Preventative Maintenance report. As per the Ontario Electrical Safety Code Rule 36-006 (1)(a), we recommend that a sign be affixed, as soon as possible, to warn unqualified personnel of the potential hazard present in this room.

2. The entrance door of the indoor substation was found to be missing a ground connection to a corresponding ground bus in this room, as previously reported in our 1999 Preventative Maintenance report. We recommend installing a ground bus in this room and bonding the door to ground, as soon as possible, to ensure that all non-current carrying components are bonded to ground.

3. We were unable to locate a rubber switching mat for the indoor switchgear. We recommend that a rubber switching mat be installed, at your earliest convenience, to maintain adequate dielectric properties for personnel during switching operations.

4. During the maintenance, it was noticed that there are no warning signs located on the switchgear located in this room. As per the Ontario Electrical Safety Code rule 36-006 (1) (a), a warning sign should be installed at your earliest convenience.

5. We were unable to locate any smoke detection devices within the indoor substation room. We recommend that a device be installed and wired to an alarm panel, as soon as possible.

6. We recommend that a co-ordination study be completed involving all of the electrical equipment associated with the Scott Street Substation. All of the protective relays were found to have discrepancies and we recommend verifying with the coordination study to determine if the values are correct or if these relays are in need of repair.

RONDAR INC.

Section 9

BUDGETARY QUOTATION
Scott Street Substation Upgrade

RONDAR INC.

September 25, 2006

Midland PUC
16984 Highway 12
P.O. Box 820
Midland, Ontario
L4R 4P4

Attention: **Mr. Wayne Dupuis**
Operations Manager

Subject **Scott Street Substation Upgrade**
Our Budgetary Quotation No. T-6989 Revised

Dear Sir:

In response to your request, we are pleased to submit our budgetary quotation to complete the work as itemized below.

Our quotation is based on preliminary discussions during our meeting on October 4, 2005.

Item #1 – Transformer Replacement
To provide the technical manpower, equipment, transportation and disposal services to remove the existing 3000kVA transformer, s/n 1-1028, and install a 5000kVA, s/n 02-1754, currently in the possession of Midland PUC.

Our Budgetary Quotation includes the following:

- Prep the substation for transformer removal.
- Transportation and lifting costs.
- Disposal of the insulating fluid.
- Disposal of the 3000kVA transformer.
- Installation of the 5000kVA transformer and associated connectors
- Removal of existing bus duct and installation of a cable duct rated 5kV, 1000A capacity mounted in cable tray.
- ESA Plan Approval and the first regular time hour charge of an ESA Site Inspector. Any additional regular time and any overtime charges will be billed as an extra.

Based On Regular Time (Budgetary)...$ 60,000.00

Qualifications

- Midland PUC is responsible for removal of asbestos from the substation enclosure prior to work commencing.

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Tel: (416) 286-2444 Fax: (416) 286-2445 E-mail: dbrown@rondar.com

Item #2 – Secondary Switchgear Replacement
To provide the engineering services, technical manpower, material and equipment necessary to replace the existing 5kV switchgear with new 5kV Medium Voltage Metal Clad Switchgear with Vacuum Breakers.

Our Budgetary Quotation includes the following:

- Supply of four (4) cells of 5kV, 3000A switchgear.
- Supply of five (5) Vacuum draw-out vacuum circuit breakers including one (1) 2000A Main Breaker and four (4) 1200A Feeder Breakers.
- Supply and installation of one (1) set of three (3) 1/c 500MCM feeder cables encased in a concrete duct bank between one (1) breaker cell and the outdoor pole structure. Connection to the 5kV distribution lines to be completed by Midland PUC.

Based On Regular Time (Budgetary) .... $ 435,000.00

Qualifications

1. Midland PUC is responsible for installation of a larger access door into the substation building prior to work commencing.
2. Midland PUC to provide a lifting vehicle for removal of the old medium voltage switchgear and placement of the new medium voltage switchgear into the substation building.
3. Our quotation includes ESA Plan Approval and the first regular time hour charge of an ESA Site Inspector. Any additional regular time and any overtime charges will be billed as an extra.
4. The cost associated with drilling new cable duct holes into the existing cable pit is unknown and is not included with our quotation.

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Tel: (416) 286-2444 Fax: (416) 286-2445 E-mail: dbrown@rondar.com

RONDAR INC.

Item #3 – Relay Protection Upgrade
To supply the engineering services, technical manpower and material necessary to replace the existing induction style relays with microprocessor based protection devices.

Our proposal is to install four (4) Schweitzer Protection and Breaker Control Relay SEL -351S-5 on each of the feeder breakers. We have also included the Schweitzer communication processor SEL-2020 that would provide the necessary communication between the protection relays and your existing supervisory system. The communication processor would be necessary for remote operation.

Our quotation includes the supply of the following:

- Supply of one (1) coordination study, short circuit analysis, ground grid calculation and device analysis.
- Supply of one (1) freestanding NEMA 12 enclosure with one overhead light, front and rear door access.
- Supply of five (5) Schweitzer Protection and Breaker Control Relays SEL-351S-5, manual included with this proposal.
- Supply of one (1) Communication Processor SEL-2020, manual included with this proposal
- Drawings: Control and Protection wire schematics will be produced and supplied.
- Material necessary to connect the wiring between the switchgear and the protection relay panel.
- Relay panel to include semi flush-mounted test/isolation switches one (1) for current and one (1) for voltage per SEL 351S-5 relay.
- Provide on-site training of the functions and operation of the SEL 351S-5. Training will be completed during commissioning of the relay panel.
- ESA Plan Approval and the first regular time hour charge of an ESA Site Inspector. Any additional regular time and any overtime charges will be billed as an extra.

Based On Regular Time (Budgetary).. $ 115,000.00

Qualifications

1. Our quotation does not include costs associated with connecting and commissioning of the remote operation and communication of the relays. As per my conversation with a service representative from Surveillance, the communication processor is adaptable to their system and they can provide system support for connection and start up.

RONDAR INC.

Our quotation is based on completing Items 1, 2 & 3 at the same time.

Upon completion of our work, a commissioning report including our engineering studies, as built control drawings, wiring schedules and new equipment manuals will be submitted.

We thank you for the opportunity to quote and look forward to serving you in this regard. If you require any additional information or assistance, please do not hesitate to contact our office.

RONDAR INC.

Dan Brown, A.Sc.T.
Technical Service Representative

Terms and Conditions

Terms of payment are net 15 days. Interest will be charged on all overdue accounts at the rate of 2% per month (24% per annum). Price is net and firm for 30 days from the date of quotation. Hydro and Electrical Safety Authority fees are extra if applicable. Taxes are extra if applicable. Delays not related to Rondar would be charged as an extra. Additional labour required by the Customer and/or its Union, other than that quoted by Rondar, will be billed as an extra. Unless otherwise indicated, this work will be performed during normal working hours, 8:00 a.m. to 4:30 p.m., Monday to Friday. Other terms and conditions are attached.

20 Venture Drive, Unit 9 Scarborough, Ontario M1B 3R7
Tel: (416) 286-2444 Fax: (416) 286-2445 E-mail: dbrown@rondar.com

RONDAR INC.

TERMS AND CONDITIONS

THIS QUOTATION IS MADE SUBJECT TO THE FOLLOWING TERMS AND CONDITIONS WHICH MAY NOT BE VARIED EXCEPT BY WRITTEN INSTRUMENT SIGNED BY A DULY AUTHORIZED REPRESENTATIVE OF RONDAR INC. ('RONDAR').

1. **ACCEPTANCE:** This quotation is made subject to approval by **Rondar** of Purchaser's credit and, subject to such approval, is open for acceptance for a period of thirty (30) days unless otherwise specified within our proposal.

2. **PRICES, TAXES AND PAYMENTS:** The prices quoted are in Canadian Dollars and unless otherwise stated herein are exclusive of all taxes. In the cases where taxes (including Federal and Provincial Sales, use or other taxes), are included, any changes to the tax rate after the quotation are to the Purchaser's account. Prices quoted are based on rates for work performed during **Rondar's** normal business hours. Overtime work involves extra charges unless otherwise specified. **Rondar** shall be entitled to charge reasonable storage charges over the prices quoted where storage of repaired equipment results from any cause for which Purchaser is directly or indirectly responsible. Where any work is delayed as a result of any cause for which Purchaser is directly or indirectly responsible, the date for determining the date on which payment is due for the work shall be the date upon which **Rondar** advises Purchaser as to its ability to perform. **Rondar** may request payment in advance notwithstanding payment terms specified if in the opinion of **Rondar,** Purchaser's financial condition does not at any time warrant continuation of work. Any payments not made to **Rondar** when due shall be subject to a service charge of 2% per month (24% per annum) provided that the foregoing is not to be construed as permitting any extension of time for payment.

3. **COMPLETION OF WORK:** Any completion dates specified are subject to events of force majeure and the receipt from Purchaser of all information necessary to allow maintenance of **Rondar's** schedule.

4. **FORCE MAJEURE:** **Rondar** shall not be responsible or liable for any loss, damage, detention or delay caused by war, invasion, insurrection, riot, the order of any civil or military authority, or by fire, flood, weather or other acts of the elements, breakdown, lockouts, strikes or labour disputes, the failure of **Rondar's** supplier to meet their contractual obligations or any other cause beyond the reasonable control of **Rondar** including any default of Purchaser and the time for the performance by **Rondar** of any of its obligations shall be extended by an amount of time equal to the delay caused by any such event.

5. **INCLEMENT WEATHER:** **Rondar** may cancel any work scheduled where inclement weather is forecasted. If **Rondar** cancels and Purchaser wishes work to proceed, Purchaser shall be liable for charges relating to additional time to complete the work or for reasonable cancellation charges in the event work cannot proceed. Reasonable cancellation charges shall include travel charges and minimum of 4 hours per person charge.

6. **HYDRO DELAYS:** On disconnecting and reconnecting power source, any delay caused by Hydro, Purchaser shall be charged as an extra.

7. **WARRANTY:** **Rondar** warrants that the specific equipment or part serviced under this contract will not fail for a period of one (1) year from commencement of the servicing by **Rondar**. Provided that **Rondar** may notify Purchaser if in **Rondar's** opinion, the equipment cannot be adequately repaired or serviced and **Rondar** shall have no further obligation hereunder. **Rondar's** warranty remains in effect provided the equipment is properly maintained and operated in accordance with the manufacturer's and **Rondar's** maintenance instructions and that the equipment is not moved for any reasons whatsoever after the servicing. This warranty only applies to equipment failures that can be proven to be a direct result of the repair servicing performed by **Rondar**, i.e. failures caused by other events or reasons not directly related to **Rondar's** repair work are not covered by this warranty. Should the customer's equipment fail during **Rondar's** one (1) year warranty period, **Rondar** will refund to the customer, the portion of the contract price (less all taxes) associated with specific part of the equipment giving rise to the claim, provided that the customer immediately informs **Rondar** of said claim in writing. Under no circumstances will **Rondar** be liable for an amount exceeding the original contract price (less all taxes). This warranty expressly excludes failures caused by acts of God, acts of third parties and negligent acts of the Purchaser. A warranty refund to the Purchaser shall not renew nor extend the warranty. **Rondar** will not directly give nor cause to be implied this equipment warranty on any contacts that do not involve direct servicing of equipment by **Rondar** (engineering studies, laboratory work, and oil processing do not constitute direct servicing). The foregoing constitutes the only warranties of **Rondar** and there are no other warranties or conditions, expressed or implied, statutory or otherwise, relating to the work to be performed or to the parts or components to be supplied by **Rondar** under this quotation. This warranty is not transferable to a third party without the expressed written consent of a duly authorized representative of **Rondar**.

8. **LIMITATION OF LIABILITY:** Notwithstanding any other provisions herein contained or any applicable statutory provisions, **Rondar** shall not be liable to Purchaser or third parties for special consequential damages or damages for loss or use arising directly or indirectly from any breach of agreement resulting from the acceptance of this quotation, fundamental or otherwise, or from any tortuous acts or omissions of its employees or agents. The liability of **Rondar** with respect to any defective work or any part of the work which is subject to late completion shall not exceed the unit price of such defective or late work, as the case may be, and in no event, shall the total liability of **Rondar** exceed the total amount paid by Purchaser for the work performed hereunder.

9. **SCOPE OF WORK:** Obligations of **Rondar** are limited to the work specified in this quotation. **Rondar** shall not be liable for any failure of Purchaser to be specific nor for any inaccuracy in delineating the work. The definition of the scope of work is the sole responsibility of Purchaser.

10. **COMPLETE AGREEMENT:** If accepted within the time period above, the terms and conditions of this quotation shall constitute the entire agreement between Purchaser and **Rondar** with respect to the subject matter hereof. Such agreement shall not be amended except by written instrument signed by a duly authorized representative of **Rondar** and shall be governed by the laws of the Province of Ontario.

Summary of Asset Additions

The Gross Capital Assets Table provides a breakdown of asset additions and retirements by APH USoA Number. Those asset additions and retirements having a variance greater than materiality (1%) are outlined in Exhibit 2, Tab 2, Schedule 3 above. In addition, Projects whose materiality is greater than 1% have been itemized in Exhibit 2, Tab 3, Schedule 1 above.

Summary of Asset Retirements

The Gross Capital Assets Table provides a breakdown of asset additions and retirements by APH USoA Number. Those asset additions and retirements having a variance greater than materiality (1%) are outlined in Exhibit 2, Tab 2, Schedule 3 .

Leave to Construction (under Section 92)

Not Applicable

Fixed Assets and Associated Depreciation Rates

The following is a listing of Fixed Assets and associated depreciation rates. MPUC uses the straightline method in calculating depreciation for accounting purposes in accordance with Article 510 of the APH. Amortization expense results from the amortization expense for assets in-service prior to the current year plus ½ year amortization expense on assets declared in-service in the year. Assets disposed of in the current year result in a decrease to the accumulated amortization account by removing the accumulated amortization for that asset. Amortization expense is reduced each year by the amortization of Contributions and Grants. MPUC 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.

USoA #	Acct Desc	Depreciation Rate in Years
1805	1805-Land	0
1806	1806-Land Rights	0
1808	1808-Buildings and Fixtures	20
1810	1810-Leasehold Improvements	-
1815	1815-Transformer Station Equipment - Normally Primary above 50 kV	-
1820	1820-Distribution Station Equipment - Normally Primary below 50 kV	25
1830	1830-Poles, Towers and Fixtures	25
1835	1835-Overhead Conductors and Devices	25
1840	1840-Underground Conduit	25
1845	1845-Underground Conductors and Devices	25
1850	1850-Line Transformers	25
1855	1855-Services	25
1860	1860-Meters	25
1905	1905-Land	0
1906	1906-Land Rights	0
1908	1908-Buildings and Fixtures	-

USoA #	Acct Desc	Depreciation Rate in Years
1910	1910-Leasehold Improvements	-
1915	1915-Office Furniture and Equipment	10
1920	1920-Computer Equipment - Hardware	5
1925	1925-Computer Software	5
1930	1930-Transportation Equipment – large trucks	8
1930	1930-Transportation Equipment – small trucks/vehicles	5
1935	1935-Stores Equipment	10
1940	1940-Tools, Shop and Garage Equipment	10
1945	1945-Measurement and Testing Equipment	10
1950	1950-Power Operated Equipment	-
1955	1955-Communication Equipment	5
1960	1960-Miscellaneous Equipment	10
1965	1965-Water Heater Rental Units	-
1970	1970-Load Management Controls - Customer Premises	-
1975	1975-Load Management Controls - Utility Premises	-
1980	1980-System Supervisory Equipment	15
1985	1985-Sentinel Lighting Rental Units	-
1995	1995-Contributions and Grants - Credit	25
2005	2005-Property Under Capital Leases	-
2055	2055-Construction Work in Progress--Electric	-

Materiality Analysis on Capital Additions

The materiality level set out in the Filing Guidelines is calculated as1% of net fixed assets. The calculation of the Materiality Threshold on net fixed assets is shown in the following table:

	EDR – 2006	Actual - 2006	Actual – 2007	Bridge – 2008	Test - 2009
Gross Cost	$13,072,370	$14,611,472	$15,995,366	$18,545,819	$21,138,579
Accumulated Amortization	$ 7,904,045	$ 8,875,750	$ 9,364,816	$10,024,319	$10,653,963
Net Fixed Assets	$ 5,168,325	$ 5,735,722	$ 6,630,550	$ 8,521,501	$10,484,616
Percent	1%	1%	1%	1%	1%
Threshold	$51,683	$57,357	$66,305	$85,215	$104,846

MPUC has selected the lowest materiality threshold of $51,683 to allow for the most detailed review of capital additions. Details each capital addition have been explained in Exhibit 2, Tab 2 Schedule 3 and are itemized in accordance with the APH USoA Numbers for the 2006 EDR balances, the 2006 Actual Year balances, the 2007 Actual Year balances, the 2008 Bridge Year balances and the 2009 Test Year Balances. Major capital projects exceeding the materiality threshold are presented in Exhibit 2, Tab 3, Schedule 1 for the same periods Costing of each of these capital projects is broken down by APH USoA numbers. In addition, a summary is provided at the end of each year of those projects that are not considered major but form part of the overall capital additions.

System Expansions

MPUC will have system expansions in 2008 and 2009 as a result of the extension of the underground distribution plant providing electrical services to residential and commercial developments. 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 2008 and 2009, it is estimated MPUC will pay a transfer price for the assets installed by the developer.

Capitalization Policy

MPUC Capital Planning Process:

Distribution Plant and Equipment

In the initial phase of the capital expenditure process, the Operations Department would receive copies of all developer / site plan submissions to the Corporation of the Town of Midland. MPUC is given an opportunity to comment on the submissions and also to determine where the electrical supply should come from. The Operations Department also would participate in the review with the Town of Midland Engineering Department, to be kept abreast of the major developments forecasted.

In the preparation of the annual capital expenditure plan, the Operations Manager would take the above input, most of which is development related, and adds projects that need to be undertaken to maintain the reliability and safety of the MPUC network, plus projects that need to be undertaken for short term and long term system improvements.

MPUC has six substations, four of which are over 50 years old. Due to the aging infrastructure, MPUC determined that a plan needed to be implemented dealing with the replacement of the substations to ensure the safety and reliability of the infrastructure was maintained, and in 2006, Rondar Engineering completed an assessment of the substation infrastructure. This study provided MPUC with a comprehensive listing of requirements for each of the substations which were then encompassed into MPUC's capital plan.

For the 2008 capital plan, in addition to the substation projects, in 2007 MPUC determined what additional capital projects would be required for the 2008 year and obtained quotes from three contractors. These quotes were compared to the cost of completing the projects using inhouse resources. This process served as the basis upon which the 2008 and 2009 capital projects were budgeted. It was found that inhouse resources would provide the best economies to MPUC and accordingly, the projects in 2008 and 2009 were budgeted using MPUC resources in place of outside contractors.

MPUC completes ground inspections throughout the year while completing maintenance on the distribution system and other infrastructure.

All of the above is taken into consideration in the development of MPUC's capital plan. This document is a live document and is updated on a regular basis.
Prior to committing to a budgeted project, MPUC prepares a Capital Project Analysis Schedule which includes a summary of the project and a detailed estimate of the costs to be incurred. This Analysis Schedule is reviewed firstly by the Management Committee. The capital expenditure is approved taking into consideration such factors as safety, reliability of current status, cost, timing and assessment of life cycle. Once approved by the Management Committee the project becomes a part of the Capital Budget Plan to be approved by the Board of MPUC.

Vehicles

MPUC 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. MPUC's vehicle replacement process considers the following criteria:

- 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.

The Management Committee reviews the vehicle replacement plan on a yearly basis. Estimates are obtained for those vehicles and the costs are included in the Analysis Schedule for inclusion in the Capital Budget which is then submitted to the Board of MPUC for approval.

Other

Each year the Management Committee looks at other plant, equipment and vehicles and determines the needs to ensure only those capital investments that are required to ensure a safe and reliable operation of MPUC's distribution system are made. As MPUC moves to increase its staff compliment in 2008, this process will become more formalized. Once the total budget is compiled by the Management Committee it is submitted to the Board of MPUC for approval. The Board approves expenditures on a yearly basis and these expenditures then form part of our capital additions for the year. Monthly tracking of project costs and other capital expenditures is completed and are compared to those costs that are budgeted.
Smaller projects (greater than $300) are included in the capitalization of assets. These projects arise as a result of unforeseen capital work that is required to be performed to maintain a safe and reliable distribution system. These projects are discussed with the Management Committee on an ongoing basis and with the Board of MPUC at their monthly meetings.

MPUC adopts the following practice for capitalization of project construction costs. All "outside" labour staff report their time on time schedules. Using this methodology allows for more accurate reporting between operating and capital expenses. Burden is allocated based on hours worked. Labour hours multiplied by the labour rate is the amount that is capitalized per project. Materials capitalized are actual material costs. Contract labour capitalization is actual costs. All other capital expenditures are capitalized based on invoice cost. At the end of the year, any shortfall of burden is allocated to the capital and expense accounts on a pro rata basis.

Capitalization Policy:

POLICY STATEMENT & PURPOSE

It is the policy of MPUC to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency and reliability of MPUC assets. The policy describes the process used for determining if expenditures should be capitalized or expensed. A materiality amount is used and any expenditure below that threshold will be expensed to operations in the current year.

GUIDELINES

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. 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. This enhancement can result in an increase in physical output or service capacity, a decrease to operating costs, extension of the useful life of the asset, or improvement in the quality of the asset's output.

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.

MATERIALITY

All additions to capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While the expenditure may meet the definition to qualify as a capital asset, a level is set, which if an expenditure falls below, it is not capitalized but charged to expense in the current period. This level is known as a materiality limit.

Materiality Limits

Identifiable Assets

Distribution Plant	$	300
General Plant	$	300

Grouped Assets

Distribution Plant	$	300
General Plant	$	300

Identifiable Assets

An identifiable capital asset that has a sufficiently high unit cost and is easily identifiable for the asset to be individually tracked and recorded.

Grouped Assets

For efficiency, capital assets may be grouped if, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a pool for the purposes of amortization.

CAPITAL ASSET RECORDS

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 generally 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.

Large and unique capital expenditures will be reviewed on an individual basis to determine the expected life and appropriate method of depreciation.

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. Transformers and meters received for the purpose of expanding the distribution system will only be capitalized once they are put in-service and will remain in inventory until that time.

Extraordinary Items

Extraordinary items will be identified separately provided they exceed the materiality threshold established by the OEB. Recovery of extraordinary items through rates as a “Z” Factor expense will follow OEB guidelines.

POLICY COMPLIANCE

All current practices will comply with OEB Accounting Procedures Handbook and the CICA Handbook. Employees must report incidents of non-compliance relating to this policy in a timely manner to the Chief Financial Officer for determination.

Allowance for Working Capital

Summary of 2009 Working Capital Allowance

Exhibit 2, Tab 1, Schedule 2 includes a Rate Base Summary Table. This table is reproduced below and provides details of the Working Capital Allowance for the 2006 EDR, the 2006 and 2007 Years, the 2008 Bridge Year and the 2009 Test Year.

Table 26 Rate Base Summary

	2006 EDR Approved	**2006 Actual**	**2007 Actual**	**2008 Projection**	**2009 Projection**
Net Capital Assets in Service:					
Opening Balance		5,729,993	5,735,722	6,630,550	8,521,501
Ending Balance		5,735,722	6,630,550	8,521,501	10,484,616
Average Balance	5,251,869	5,732,858	6,183,136	7,576,025	9,503,058
Working Capital Allowance	2,662,646	2,670,771	2,791,219	2,826,009	2,815,595
Total Rate Base	**7,914,515**	**8,403,628**	**8,974,355**	**10,402,034**	**12,318,654**
Expenses for Working Capital					
Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	272,722	374,509	352,987	392,900	455,700
3550-Distribution Expenses - Maintenance	306,118	336,041	283,582	338,200	353,900
3650-Billing and Collecting	412,100	379,313	451,821	420,400	435,800
3700-Community Relations	15,581	23,774	15,073	5,700	5,600
3800-Administrative and General Expenses	673,755	655,050	650,232	744,600	807,900
3950-Taxes Other Than Income Taxes	28,420	34,495	31,306	32,900	34,200
Total Eligible Distribution Expenses	1,708,695	1,803,182	1,785,000	1,934,700	2,093,100
3350-Power Supply Expenses	16,042,281	16,001,955	16,823,128	16,905,361	16,677,534
Total Expenses for Working Capital	17,750,976	17,805,137	18,608,129	18,840,061	18,770,634
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,662,646**	**2,670,771**	**2,791,219**	**2,826,009**	**2,815,595**

Working Capital Allowance calculations by accounts

Attached on the pages following this page is the Working Capital Allowance Table by Account for the 2009 Test Year.

Working Capital Allowance by Account

Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
		Working Capital Allowance Factor:	**15.0%**
3350-Power Supply Expenses	4705-Power Purchased	12,689,048	1,903,357
	4708-Charges-WMS	1,210,698	181,605
	4714-Charges-NW	778,572	116,786
	4716-Charges-CN	1,427,036	214,055
	4730-Rural Rate Assistance Expense	232,665	34,900
	4750-Charges-LV	339,515	50,927
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	314,900	47,235
	5010-Load Dispatching	16,000	2,400
	5012-Station Buildings and Fixtures Expense	64,000	9,600
	5016-Distribution Station Equipment - Operation Labour	8,200	1,230
	5017-Distribution Station Equipment - Operation Supplies and Expenses	17,000	2,550
	5065-Meter Expense	11,400	1,710
	5070-Customer Premises - Operation Labour	22,100	3,315
	5075-Customer Premises - Materials and Expenses	2,100	315
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	77,200	11,580
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,400	2,010
	5114-Maintenance of Distribution Station Equipment	1,600	240
	5120-Maintenance of Poles, Towers and Fixtures	6,600	990
	5125-Maintenance of Overhead Conductors and Devices	95,900	14,385

Working Capital Allowance by Account

Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
		Working Capital Allowance Factor:	**15.0%**
	5135-Overhead Distribution Lines and Feeders - Right of Way	29,300	4,395
	5150-Maintenance of Underground Conductors and Devices	33,800	5,070
	5160-Maintenance of Line Transformers	9,900	1,485
	5175-Maintenance of Meters	86,200	12,930
3650-Billing and Collecting	5310-Meter Reading Expense	96,000	14,400
	5315-Customer Billing	190,300	28,545
	5320-Collecting	68,700	10,305
	5325-Collecting- Cash Over and Short	200	30
	5330-Collection Charges	600	90
	5335-Bad Debt Expense	80,000	12,000
3700-Community Relations	5410-Community Relations - Sundry	5,600	840
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,600	4,140
	5610-Management Salaries and Expenses	285,900	42,885
	5615-General Administrative Salaries and Expenses	70,400	10,560
	5620-Office Supplies and Expenses	107,800	16,170
	5630-Outside Services Employed	75,400	11,310
	5635-Property Insurance	21,600	3,240

Working Capital Allowance by Account

Account Grouping	Account Description	2009 Projected Acct Balance	Working Capital Allowance
		Working Capital Allowance Factor:	**15.0%**
	5640-Injuries and Damages	21,700	3,255
	5655-Regulatory Expenses	73,700	11,055
	5665-Miscellaneous General Expenses	28,500	4,275
	5675-Maintenance of General Plant	90,600	13,590
	5680-Electrical Safety Authority Fees	4,700	705
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	34,200	5,130
TOTAL		**18,770,634**	**2,815,595**

Cost of Power Projections

Attached on the pages following this page is the Cost of Power Projections Table for the 2008 Bridge Year and 2009 Test Year.

Cost of Power Projections

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)		**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.05450**	**2009**	*rate ($/kWh):*	**$0.05450**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4006	4705	52,872,087		2,881,529	53,033,179		2,890,308
	kWh	General Service <50 kW	4035	4705	29,469,572		1,606,092	29,450,950		1,605,077
	kWh	General Service >50 Kw	4035	4705	152,967,409		8,336,724	148,504,837		8,093,514
	kWh	Street Lighting	4025	4705	1,247,345		67,980	1,273,628		69,413
	kWh	Sentinel Lighting	4030	4705	16,986		926	16,986		926
	kWh	Unmetered Scattered Load	4035	4705	546,982		29,811	546,982		29,811
		TOTAL			**237,120,382**		**12,923,061**	**232,826,563**		**12,689,048**
Transmission - Network		**Customer**	**Revenue**	**Expense**		**2008**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
	kWh	Residential	4066	4714	52,872,087	$0.0038	200,914	53,033,179	$0.0038	201,526
	kWh	General Service <50 kW	4066	4714	29,469,572	$0.0034	100,197	29,450,950	$0.0034	100,133
	kW	General Service >50 Kw	4066	4714	342,678	$1.4180	485,917	332,681	$1.4180	471,742
	kW	Street Lighting	4066	4714	2,989	$1.0694	3,196	3,052	$1.0694	3,264
	kW	Sentinel Lighting	4066	4714	44	$1.0749	47	44	$1.0749	47
	kWh	Unmetered Scattered Load	4066	4714	546,982	$0.0034	1,860	546,982	$0.0034	1,860
		TOTAL			**83,234,352**		**792,131**	**83,366,888**		**778,572**
Transmission - Connection		**Customer**	**Revenue**	**Expense**		**2008**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
	kWh	Residential	4068	4716	52,872,087	$0.0071	375,392	53,033,179	$0.0071	376,536
	kWh	General Service <50 kW	4068	4716	29,469,572	$0.0065	191,552	29,450,950	$0.0065	191,431
	kW	General Service >50 Kw	4068	4716	342,678	$2.5532	874,925	332,681	$2.5532	849,401
	kW	Street Lighting	4068	4716	2,989	$1.9738	5,900	3,052	$1.9738	6,024
	kW	Sentinel Lighting	4068	4716	44	$2.0150	89	44	$2.0150	89
	kWh	Unmetered Scattered Load	4068	4716	546,982	$0.0065	3,555	546,982	$0.0065	3,555
		TOTAL			**83,234,352**		**1,451,413**	**83,366,888**		**1,427,036**
Wholesale Market Service		**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00520**	**2009**	*rate ($/kWh):*	**$0.00520**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4062	4708	52,872,087		274,935	53,033,179		275,773
	kWh	General Service <50 kW	4062	4708	29,469,572		153,242	29,450,950		153,145
	kWh	General Service >50 Kw	4062	4708	152,967,409		795,431	148,504,837		772,225
	kWh	Street Lighting	4062	4708	1,247,345		6,486	1,273,628		6,623
	kWh	Sentinel Lighting	4062	4708	16,986		88	16,986		88
	kWh	Unmetered Scattered Load	4062	4708	546,982		2,844	546,982		2,844
		TOTAL			**237,120,382**		**1,233,026**	**232,826,563**		**1,210,698**
Rural Rate Protection		**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00100**	**2009**	*rate ($/kWh):*	**$0.00100**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4062	4730	52,872,087		52,872	52,872,087		52,872
	kWh	General Service <50 kW	4062	4730	29,469,572		29,470	29,450,950		29,451
	kWh	General Service >50 Kw	4062	4730	152,967,409		152,967	148,504,837		148,505
	kWh	Street Lighting	4062	4730	1,247,345		1,247	1,273,628		1,274
	kWh	Sentinel Lighting	4062	4730	16,986		17	16,986		17
	kWh	Unmetered Scattered Load	4062	4730	546,982		547	546,982		547
		TOTAL			**237,120,382**		**237,120**	**232,665,471**		**232,665**
Debt Retirement Charge		**Customer**	**Revenue**	**Expense**	**2008**	*rate ($/kWh):*	**$0.00700**	**2009**	*rate ($/kWh):*	**$0.00700**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
		TOTAL								
Low Voltage Charges		**Customer**	**Revenue**	**Expense**		**2008**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
		TOTAL (Input amount)	4075	4750		268,609.48	**268,609**		339,515.32	**339,515**
GRAND TOTAL							**16,905,361**			**16,677,534**

EXHIBIT 3 - REVENUE

Distribution Revenue

Overview of Distribution Revenue

This exhibit provides the details on MPUC's Distribution Revenues for Historical, Historical Board Approved, Bridge year and Test years. This exhibit also provides a detailed variance analysis by rate class of the Distribution Revenue components.

Distribution Revenue for the 2006 EDR has been calculated based on 2006 Board Approved Rates. In 2006, 2007 and 2008, Distribution Revenue has been calculated using the most recently approved rates in each particular year. MPUC's Distribution Revenue for the 2009 Test Year has been calculated using the 2009 proposed rates. Distribution Revenue does not include commodity revenue. A calculation of Distribution Revenues is presented in Exhibit 3, Tab 1, Schedule 3. This schedule assumes rates are effective January 1st in each year. Consequently, actual Distribution Revenues will differ as rates become effective in May of each year. A Summary of Distribution Revenues which includes actual distribution revenues for the 2006 and 2007 years are set out in Exhibit 3, Tab 1, Schedule 2.

Throughput Revenue

Information related to the utility's throughput revenue include details such as weather normalized forecasting methodology, normalized volume, customer counts forecast tables. Throughput details showing volumes, revenues, unit revenues and customer count by rate class as well as a variance analysis on the forecast information is also provided.

Other Revenue

Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these Distribution Revenues is presented in Exhibit 3, Tab 3, Schedules 1 & 2.

Summary of Distribution Revenue Table

Attached on the following page is the Summary of Distribution Revenue Table providing details for the 2006 EDR, the 2006 Actual Year, the 2007 Actual Year, the 2008 Bridge Year and the 2009 Test Year.

Summary of Distribution Revenue Table

Distribution Revenue	2009 @ new rates	2008 Projection	Var $	2008 Projection	2007 Actual	Var $	2007 Actual	2006 Actual	Var $	2006 Actual	2006 EDR Approved	Var $
Residential	1,901,008	1,772,803	128,205	1,772,803	1,682,252	90,551	1,682,252	1,661,132	21,120	1,661,132	1,645,983	15,149
General Service <50 kW	604,986	494,950	110,036	494,950	462,027	32,923	462,027	432,680	29,346	432,680	479,219	-46,539
General Service >50kW	1,472,170	810,606	661,564	810,606	719,776	90,830	719,776	727,854	-8,078	727,854	922,724	-194,870
Street Lighting	73,446	24,879	48,567	24,879	24,224	655	24,224	23,509	715	23,509	24,260	-751
Sentinel Lighting	5,574	501	5,073	501	376	125	376	676	-300	676	2,231	-1,555
Unmetered Scattered Load	16,252	8,968	7,284	8,968	10,106	-1,138	10,106	8,089	2,017	8,089		8,089
Gross Revenue (before Transformer Allowance)	4,073,436	3,112,707	960,729	3,112,707	2,898,761	213,946	2,898,761	2,853,941	44,820	2,853,941	3,074,417	-220,476
Transformer Allowance	-151,200	-151,200	0	-151,200	-147,658	-3,542	-147,658	-153,029	5,371	-153,029	-161,825	8,796
Total Revenue	3,922,236	2,961,507	960,729	2,961,507	2,751,103	210,404	2,751,103	2,700,912	50,191	2,700,912	2,912,592	-211,680
Less: Low voltage charges embedded in distribution rates	-339,515	-268,609	-70,906	-268,609	-95,602	-173,007	-95,602	-67,613	-27,989	-67,613	-284,777	217,164
DISTRIBUTION REVENUE	**3,582,721**	**2,692,898**	**889,823**	**2,692,898**	**2,655,501**	**37,397**	**2,655,501**	**2,633,299**	**22,202**	**2,633,299**	**2,627,815**	**5,484**

Other Distribution Service Revenue	2009 @ new rates	2008 Projection	Var $	2008 Projection	2007 Actual	Var $	2007 Actual	2006 Actual	Var $	2006 Actual	2006 EDR Approved	Var $
4080-Distribution Services Revenue	15,825	15,825	-0	15,825	15,831	-6	15,831	16,271	-440	16,271	129,402	-113,131
4090-Electric Services Incidental to Energy Sales	0	0	0	0	0	0	0		0		16,205	-16,205
4210-Rent from Electric Property	82,481	82,481	0	82,481	81,661	819	81,661	88,519	-6,858	88,519	56,499	32,020
4220-Other Electric Revenues	0	0	0	0	2,110	-2,110	2,110	1,315	795	1,315	354	961
4225-Late Payment Charges	10,000	10,000	0	10,000	8,121	1,879	8,121	13,730	-5,609	13,730	24,085	-10,355
4230-Sales of Water and Water Power	0	0	0	0	0	0	0	0	0	0	16,605	-16,605
4235-Miscellaneous Service Revenues	91,625	91,625	0	91,625	93,477	-1,852	93,477	81,660	11,817	81,660	18,399	63,261
4325-Revenues from Merchandise, Jobbing, Etc.	82,000	82,000	0	82,000	78,471	3,529	78,471	57,136	21,335	57,136	175,024	-117,888
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-60,800	-60,800	0	-60,800	-47,624	-13,176	-47,624	-37,329	-10,295	-37,329	-139,514	102,185
4355-Gain on Disposition of Utility and Other Property	0	0	0	0	36,734	-36,734	36,734	1,040	35,694	1,040	0	1,040
4405-Interest and Dividend Income	10,000	30,000	-20,000	30,000	74,750	-44,750	74,750	62,682	12,068	62,682	33,250	29,432
TOTAL OTHER DISTRIBUTION SERVICE REVENUE	**231,131**	**251,131**	**-20,000**	**251,131**	**343,533**	**-92,402**	**343,533**	**285,024**	**58,509**	**285,024**	**330,308**	**-45,284**
Distribution Revenues (see above)	**3,582,721**	**2,692,898**	**889,823**	**2,692,898**	**2,655,501**	**37,397**	**2,655,501**	**2,633,299**	**22,202**	**2,633,299**	**2,627,815**	**5,484**
TOTAL DISTRIBUTION REVENUES	**3,813,852**	**2,944,029**	**869,823**	**2,944,029**	**2,999,034**	**-55,005**	**2,999,034**	**2,918,323**	**80,710**	**2,918,323**	**2,958,123**	**-39,800**

Calculations of Distribution Revenue Table

Attached on the following page is the Calculation of Distribution Revenue Table for the 2006 EDR Approved Year, the 2006 Actual Year, the 2007 Actual Year, the 2008 Bridge Year and the 2009 Test Year.

Calculation of Distribution Revenue Table

2006 EDR Approved	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge *	Distribution Revenue
Residential	5,568	8,342	0	$0.0196		$11.01	1,645,983
General Service <50 kW	726	36,921	0	$0.0139		$12.24	479,219
General Service >50 Kw	129	1,267,176	3,046		$2.2942	$13.67	922,724
Street Lighting	1,469	886	2		$2.3515	$0.95	24,260
Sentinel Lighting	114	310	1		$2.6020	$1.45	2,231
Unmetered Scattered Load	0	0	0				0
Gross Revenue (before Transformer Allowances)							**3,074,416**
Transformer Allowances							-161,825
Total Revenue							**2,912,591**
Less: Low voltage charges embedded in distribution rates							-284,777
DISTRIBUTION REVENUE							**2,627,814**
** Excluding Smart Meter Rate Adder*							

2006 Actual	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge *	Distribution Revenue
Residential	5,746	8,089	0	$0.0196		$11.01	1,670,169
General Service <50 kW	714	36,335	0	$0.0139		$12.24	465,482
General Service >50 Kw	106	1,435,423	3,421		$2.2942	$13.67	849,270
Street Lighting	1,523	730	2		$2.3515	$0.95	24,722
Sentinel Lighting	26	976	3		$2.6020	$1.45	627
Unmetered Scattered Load	0	0		$0.0139		$12.24	0
Gross Revenue (before Transformer Allowances)							**3,010,270**
Transformer Allowances							-153,029
Total Revenue							**2,857,241**
Less: Low voltage charges embedded in distribution rates							-67,613
DISTRIBUTION REVENUE							**2,789,628**
Note: Schedule is based on 12 months of consumption at May 1, 2006 rates. Actual 2006 Revenues are a combination of rates in effect May 1, 2006 and May 1, 2005.							
** Excluding Smart Meter Rate Adder*							

2007 Actual	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge *	Distribution Revenue
Residential	5,834	8,208	0	$0.0198		$11.11	1,725,940
General Service <50 kW	722	37,494	0	$0.0140		$12.35	485,987
General Service >50 Kw	107	1,382,557	3,299		$2.3148	$13.79	834,775
Street Lighting	1,525	752	2		$2.3727	$0.96	24,513
Sentinel Lighting	22	725	2		$2.6254	$1.46	501
Unmetered Scattered Load	12	42,796	0	$0.0140		$12.35	8,968
Gross Revenue (before Transformer Allowances)							**3,080,684**
Transformer Allowances							-147,658
Total Revenue							**2,933,026**
Less: Low voltage charges embedded in distribution rates							-95,602
DISTRIBUTION REVENUE							**2,837,424**
Note: Schedule is based on 12 months of consumption at May 1, 2007 rates. Actual 2007 Revenues are a combination of rates in effect May 1, 2007 and May 1, 2006.							
** Excluding Smart Meter Rate Adder*							

2008 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge *	Distribution Revenue
Residential	5,925	8,378	0	$0.0198	$0.0000	$11.11	1,772,803
General Service <50 kW	726	38,111	0	$0.0140	$0.0000	$12.35	494,950
General Service >50 Kw	105	1,367,789	3,264	$0.0000	$2.3148	$13.79	810,606
Street Lighting	1,544	758	2	$0.0000	$2.3727	$0.96	24,879
Sentinel Lighting	22	725	2	$0.0000	$2.6254	$1.46	501
Unmetered Scattered Load	12	42,796	0	$0.0140	$0.0000	$12.35	8,968
Gross Revenue (before Transformer Allowances)							**3,112,707**
Transformer Allowances							-151,200
Total Revenue							**2,961,507**
Less: Low voltage charges embedded in distribution rates							-268,609
DISTRIBUTION REVENUE							**2,692,898**
Note: Schedule is based on 12 months of consumption at May 1, 2008 rates.							
** Excluding Smart Meter Rate Adder*							

2009 Projection	Customers (Connections)	kWh's per Customer (Connection)	kW's per Customer (Connection)	Dist. Rate per kWh	Dist. Rate per kW	Monthly Service Charge *	Distribution Revenue
Residential	6,018	8,274	0	$0.0211	$0.0000	$11.81	1,901,008
General Service <50 kW	729	37,930	0	$0.0171	$0.0000	$15.09	604,986
General Service >50 Kw	103	1,353,671	3,230	$0.0000	$4.2097	$57.99	1,472,170
Street Lighting	1,564	765	2	$0.0000	$18.1614	$0.96	73,446
Sentinel Lighting	22	725	2	$0.0000	$117.9289	$1.46	5,574
Unmetered Scattered Load	12	42,796	0	$0.0282	$0.0000	$12.35	16,252
Gross Revenue (before Transformer Allowances)							**4,073,435**
Transformer Allowances							-151,200
Total Revenue							**3,922,235**
Less: Low voltage charges embedded in distribution rates							-339,515
DISTRIBUTION REVENUE							**3,582,720**
Note: Schedule is based on 12 months of consumption at May 1, 2009 rates.							
** Excluding Smart Meter Rate Adder*							

Variance Analysis on Distribution Revenue

Distribution Revenue for the 2006 EDR has been calculated based on 2006 Board Approved Rates. In 2006, 2007 and 2008, Distribution Revenue has been calculated using the most recently approved rates in each particular year. MPUC's Distribution Revenue for the 2009 Test Year has been calculated using the 2009 proposed rates. Distribution Revenue does not include commodity revenue. A Calculation of Distribution Revenue Table is presented in Exhibit 3, Tab 1, Schedule 3. This schedule assumes rates are effective January 1st in each year. Consequently, actual Distribution Revenues for the 2006 and 2007 year, as shown in the Summary of Distribution Revenue Table, will differ as rates become effective in May of each year.

A Summary of Distribution Revenue Table is presented in Exhibit 3, Tab 1, Schedule 2 which is based on 2006 EDR balances, 2006 and 2007 actual year data and the forecasted data for 2008 and 2009. Forecasted data for all years is provided in Exhibit 3, Tab 2, Schedules 2, 3 and 4. The Summary of Distribution Revenue Table provides details on the variances in Distribution Revenues and Other Distribution Revenues.

2006 Actual Year vs. 2006 EDR

MPUC's total Distribution Revenue, including Other Distribution Revenues for the 2006 Actual Year totaled $2,918,323 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,633,299 or 90.2% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $285,024. In comparison the total Distribution Revenue, including Other Distribution Revenues for the

2006 Board Approved totalled $2,958,123, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,627,815 or 88.8% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $330,308. Distribution Revenues increased by $5,484 in 2006 over the 2006 EDR. The 2006 EDR Distribution Revenues were based on 2004 actual revenues. The low voltage charges of $284,777 included in the 2006 EDR were based on an estimate over a 12 month period. The rate effective date in 2006 was May 1, 2006 and consequently, low voltage was not paid for the full year. This difference along with the difference in revenues between 2004 and the 2006 year would account for the total variance.

2007 Year vs. 2006 Actual Year

MPUC's total Distribution Revenue including Other Distribution Revenues totalled $2,999,034 for the 2007 Year, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,655,501 or 88.5% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $343,533. In comparison, the total Distribution Revenue, including Other Distribution Revenues for the 2006 Actual Year were $2,918,323 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,633,299 or 90.2% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $285,024. Distribution Revenues increased by $22,202 in 2007 over the 2006 Year. The main cause of this increase was the increase in revenues from Residential and GS<50kW customers a decrease in revenues from the GS>50kW class due to the bankruptcy of one of our customers and as well, the incorporation of low voltage charges into distribution rates for the full year.

2008 Bridge Year vs. 2007 Actual Year

MPUC's total Distribution Revenue, including Other Distribution Revenues is forecast to be $2,944,029 for Bridge 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,692,898 or 91.2% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $251,131. In comparison, Distribution Revenue, including Other Distribution Revenues totalled $2,999,034 for the 2007 Year, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,655,501 or 88.5% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $343,533. Distribution Revenues is forecast to increase by $37,397 in 2008 over the 2007 Year.

2009 Test Year vs. 2008 Bridge Year

MPUC's total Distribution Revenue, including Other Distribution Revenues is forecast to be $3,813,852 for Fiscal 2009 as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $3,582,721 or 93.9% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $231,231. In comparison, total Distribution Revenue, including Other Distribution Revenues is forecast to be $2,944,029 for Bridge 2008, as shown in Exhibit 3, Tab 1, Schedule 2. Distribution revenue totals $2,692,898 or 91.2% of total revenues. Other Distribution Revenues (net) account for the remaining revenue of $251,131. Distribution Revenues are projected to increase by $869,823 due to increase in rates and volume of customers and an increase in low voltage charges.

Throughput Revenue

Weather Normalization Forecasting Methodology

A weather normal load forecast has been used for MPUC's rate application. Weather normalization involves removing the year-to-year variations in consumption due to weather. This is achieved by estimating a statistical relationship between observed monthly weather and observed monthly consumption. In addition to weather, monthly consumption can also be affected by the number of weekdays and holidays in the month and economic factors (such as growth or decline). These factors are also accounted for in the statistical relationship.

Once the statistical relationship between monthly weather and consumption is obtained, year-to-year variance in weather conditions is controlled for by defining a "weather normal" month. For MPUC purposes, MPUC adopted the most recent 10-year average weather data from 1998 to 2007 of observed weather in each month as the definition of "weather normal". For the purposes of this load forecast, monthly weather observations describing the extent of heating degree days (HDD – the number of Celsius degrees that the mean temperature is below 18°C) or cooling degree days (CDD – the number of Celsius degrees that the mean temperature is above 18°C) as reported at Pearson International Airport have been used. The historical consumption are weather normalized by replacing actual observed weather with normal weather in the statistical relationship to obtain what consumption would have been if weather had been "normal". Future consumption is forecast based on normal weather and forecast economic and timing variables. Monthly full–time employment levels for the Kitchener-Waterloo-Barrie economic regions, along with non-holiday weekdays were used in the regression equations for the load forecast.

Energy consumption for MPUC's residential and GS<50 classes showed strong correlations with weather, and regression equations were used to weather normalize and forecast kWh consumption for these classes. The GS>50 class peak days did not show a statistically significant correlation with weather, therefore the GS>50 class was classified as non-weather sensitive along with the Street Lighting, Sentinel Lighting and USL classes. The KW's for non-weather sensitive classes were calculated by determining the annual average KW/kWh ratio and multiplying this ratio by the forecast kWh in the year. These forecasts were based on the consumption trend over the past two years (2006 & 2007), with the exception of Sentinel Lighting and USL which held flat at the 2007 level as no change in the number of connections or accounts is anticipated going forward.

In our application, the weather normalization (where required) is based on monthly class specific wholesale, retail, and customer number data from May 2002 to December 2007. This weather-normalized throughput was generated by Elenchus Research Associates (ERA) using regression equations. Attached on the pages following this page is a copy of MPUC's Weather Normalized Load Forecast for 2008 and 2009 prepared by Elenchus Research Associates.

Medium Term Weather Normalized Distribution System Load Forecast 2008 to 2009

Prepared for

Midland Power Utility Corporation

June 9, 2008

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Midland PUC's rebasing rate application for 2009 rates. A weather normal load forecast is developed for the bridge year (2008) and test year (2009) and weather normalized historical consumption is also derived.

For the most part, the forecast for Midland PUC is based on monthly class specific retail data from May 2002[1] to December 2007. The retail metered data has been prorated to represent calendar month consumption. That is, the billing data has been adjusted to account for unbilled amounts, the effect of meter reading dates, etc. The retail consumption amounts do not include losses; therefore, distribution system losses are not part of the class retail volumes. These volumes will need to be adjusted for distribution system losses to reconcile with wholesale purchases by the LDC. In addition, the billed amounts have been adjusted to correct for erroneous readings from a defective wholesale meter for the period of April 10 to October 5, 2006 and December 2006, as indicated by the IESO.

Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating). We have tried to incorporate variables to account for these factors in considering Midland's load and correcting for weather anomalies.

In order to isolate demand determinants at the class specific level, we have estimated equations to weather normalize and forecast kWh consumption for the residential and GS<50 classes. In analysing Midland's GS>50 class data, we have determined that consumption in this class is not correlated with weather (see details below).

[1] It was not possible to obtain data prior to May 2002.

Consumption for street lighting, sentinel lighting, and unmetered scattered load (USL) classes is also not weather sensitive. The forecast for these classes is based on trend consumption. The trend consumption in these classes is generally consistent with the trend in customer counts in these classes, which gives confidence in the results. We have calculated the class kW demand (where applicable) by applying an annual average kW/kWh ratio based on historical values to annual class kWh. Results are outlined in Section 2 below.

2 CLASS SPECIFIC NORMALIZED AND FORECAST RESULTS

In order to determine the relationship between observed weather and energy consumption, monthly weather observations describing the extent of heating or cooling required within the month are necessary. Environment Canada publishes monthly observations on heating degree days (HDD) and cooling degree days (CDD) for selected weather stations across Canada. Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18°C. Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18°C. For Midland, we have used monthly HDD and CDD as reported at Pearson International Airport near Toronto.

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. We have used the monthly full-time employment levels for the Kitchener-Waterloo-Barrie economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series v2054776).

Finally, we have used the number of non-holiday weekdays in the month to account for peak day consumption. We have included New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, August Civic Holiday (Simcoe Day), Labour Day, Thanksgiving Day, Christmas and Boxing Day. From 2008, we have included the Ontario Family Day holiday in February, but we have not included Remembrance Day in

November. The historical data for monthly employment and peak days are displayed in *table 1* below.

Table 1
Monthly Peak Days

	2002	2003	2004	2005	2006	2007
January	22	21	21	20	21	22
February	20	20	20	20	20	20
March	20	21	23	21	23	22
April	21	20	20	21	18	19
May	22	21	20	21	22	22
June	20	21	22	22	22	21
July	22	22	21	20	20	22
August	21	20	21	22	22	22
September	20	21	21	21	20	19
October	22	22	20	20	21	22
November	21	20	22	22	22	22
December	20	21	21	20	19	19
	Full-time employment ('000s Kit-Wat-Barrie, Ontario					
January	446.2	467.1	487.3	508.9	519.2	529.2
February	447.6	464.2	484.4	507.7	517.6	520.2
March	449.1	463.4	483.5	503.0	517.8	514.6
April	455.2	467.9	483.2	503.4	522.2	512.1
May	460.2	477.4	489.5	513.2	530.1	512.2
June	466.6	482.9	498.3	521.6	537.6	523.0
July	473.9	489.7	509.8	531.3	547.6	537.9
August	478.5	497.1	515.2	537.9	555.4	549.6
September	475.1	498.3	515.8	537.0	553.9	548.0
October	469.5	499.2	509.3	530.4	550.0	541.9
November	464.1	493.0	504.4	522.4	542.5	536.1
December	467.9	490.8	506.2	521.6	538.6	535.2
Ann % chg	***1.1%***	***4.3%***	***3.4%***	***4.2%***	***3.1%***	***-1.1%***

Using this data, regression equations describing the relationship between monthly actual energy and the explanatory variables were estimated for residential and GS<50 classes. In analyzing the GS>50 kW class monthly kWh, the monthly profile did not appear to be particularly well correlated with observed weather. A correlation matrix of GS > 50 kW class monthly kWh, monthly HDD and monthly CDD is displayed in *Table 2* below:

Table 2 Correlation coefficients, using the observations 2002:05 - 2007:12
5% critical value (two -tailed) = 0.2387 for n = 68

GSgt50kWh	HDD	CDD	
1.0000	0.1834	0.1314	GSgt50kWh
	1.0000	-0.7214	HDD
		1.0000	CDD

The results for residential and GS<50 consumption show strong correlation with weather, as expected. Midland's residential kWh consumption is influenced by weather and economic factors (employment). Peak days did not show a statistically significant influence (which is not atypical for residential load).

Results for Residential kWh

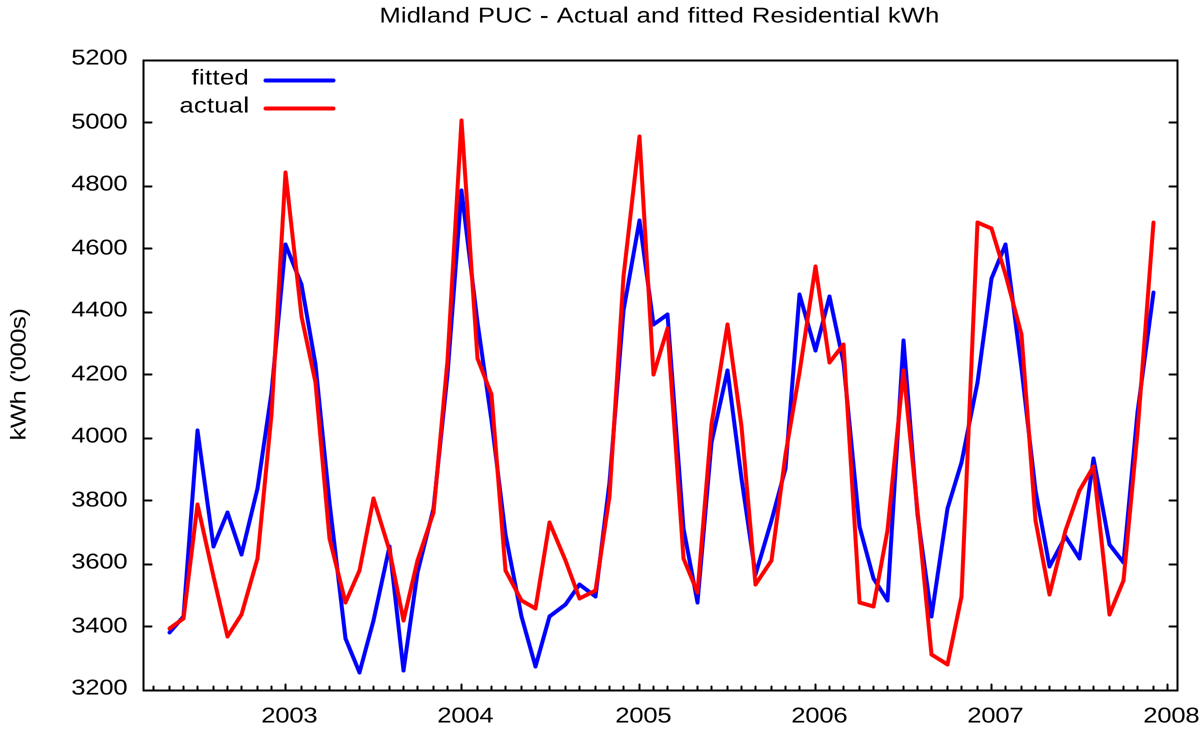
Res kWh = ¦ (HDD, CDD, Employ) + const

OLS estimates using the 68 observations 2002:05-2007:12

Unadjusted R^2 = 0.823651
Adjusted R^2 = 0.815385
F-statistic (3, 64) = 99.6388 (p-value < 0.00001)
Durbin-Watson statistic = 1.70571

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	1,199,840.0	2.5471	0.01328
HDD	2,184.1	17.036	<0.00001
CDD	13,975.4	9.9892	<0.00001
FTE Employ	3,406.4	3.7689	0.00036

Actual and fitted values are plotted in the chart below:



Energy consumption in the GS<50 kW class for Midland correlated with weather and peak days, but did not show any statistical correlation with economic factors.

Results for GS < 50 kW Class kWh

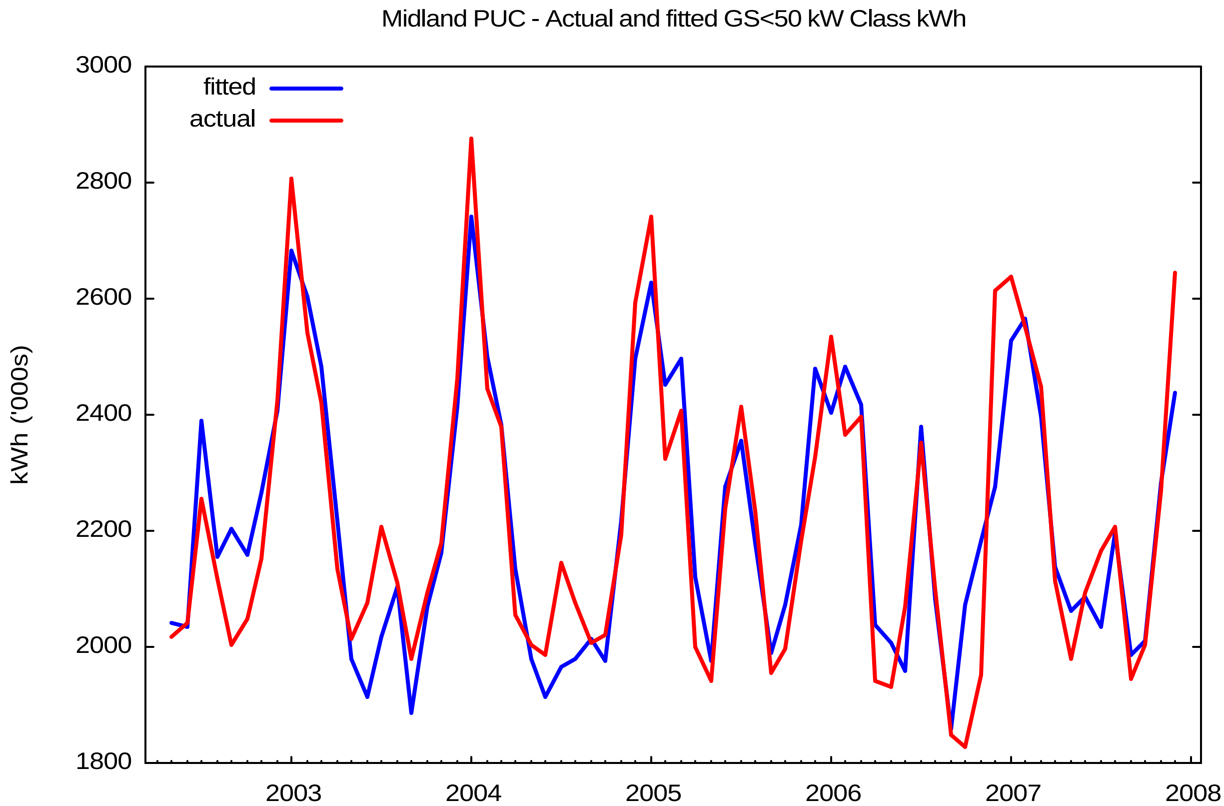
GS<50 kWh = ¦ (HDD, CDD, Peak days) + const

OLS estimates using the 68 observations 2002:05-2007:12

Unadjusted R^2 = 0.816591
Adjusted R^2 = 0.807994
F-statistic (3, 64) = 94.9822 (p-value < 0.00001)
Durbin-Watson statistic = 1.6033

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	1,319,790.0	4.8378	<0.00001
HDD	1,194.9	16.6101	<0.00001
CDD	7,957.4	10.0912	<0.00001
PeakDays	17,484.4	1.3739	0.17427

Actual and fitted values are plotted in the chart below:



Annual estimates are compared to actual values in the table below. Mean absolute percentage error (MAPE) for annual estimates for the period is less than 5%.

Table 3 – Midland PUC – Annual Predicted vs. Actual

Year	*Actual Residential kWh*	*Predicted kWh*	*Error*	*Actual GS<50 kWh*	*Predicted kWh*	*Error*
2003	46,627,475	47,371,079	1.59%	27,036,581	27,556,977	1.92%
2004	46,604,134	46,285,982	-0.68%	26,788,352	26,603,080	-0.69%
2005	48,370,214	51,434,940	6.34%	26,768,115	29,012,118	8.38%
2006	46,479,977	49,034,510	5.50%	25,943,176	27,289,237	5.19%
2007	47,886,438	50,279,780	5.00%	27,070,448	28,157,267	4.01%
		Mean Absolute Percent Error	*3.82%*			*4.04%*

2.1 WEATHER NORMALIZATION AND FORECASTED KWH

It is not possible to accurately forecast weather for months or years in advance. Therefore, one can only base future weather expectations on what has happened in the past. Individual years may experience unusual spells of weather (unusually cold winter, unusually warm summer, etc.). However, over time, these unusual spells "average" out.

While there may be trends over several years (e.g., warmer winters for example), using several years of data rather than one particular year filters out the extremes of any particular year. For Midland, the 10 year average from 1998 to 2007 has been adopted as the appropriate definition of weather normal. Other definitions also exist. Environment Canada publishes 30 year “Climate Normal” data based on observations from 1971 to 2000. The OEB has considered yet others (for example, a five-year rolling average used to predict heating degree days for bridge year and test year in the case of Natural Resource Gas Limited (RP-2004-0167)). Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the “average” weather experienced in recent years. Others have also adopted this definition (for example, Toronto Hydro Electric System Limited in EB-2005-0421 and EB-2007-0680).

Presented below is a table outlining the 10-year and 30-year average monthly HDD and CDD for Pearson International Airport.

Table 4 – 30-yr and 10-yr HDD and CDD, Pearson Int'l Airport

	1971-2000 30yr normal		1998-2007 10yr normal	
	HDD	**CDD**	**HDD**	**CDD**
Jan	752.9	0.0	700.31	0.0
Feb	662.1	0.0	609.23	0.0
Mar	571.6	0.0	531.4	0.0
Apr	353.3	1.1	320.17	1.21
May	171.8	12.0	143.43	14.95
Jun	49.4	44.2	31.27	77.28
Jul	8.9	96.7	2.39	132.97
Aug	17.8	75.0	4.79	116.29
Sep	102.5	22.1	50.92	43.01
Oct	282.6	1.0	237.69	4.32
Nov	445.5	0.0	397.36	0.0
Dec	647.4	0.0	602.05	0.0
Annual	**4,065.8**	**252.1**	**3,631.0**	**390.0**

Forecasts for Ontario's employment outlook for 2008 and 2009 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Table 5 - Employment Forecast – Ontario
(figures in annual percentage change)

	BMO *(Winter 2008)*	RBC *(April 2008)*	Scotia *(March 31, 2008)*	TD *(April 16,2008)*	avg
2008	0.7	0.9	1.1	1.0	0.9
2009	0.7	1.0	0.7	0.4	0.7

Incorporating the forecast economic variables, monthly peak days, and 10-yr weather normal heating and cooling degree days, the following weather corrected consumption and forecast values are calculated:

Table 6 - Weather Corrected Consumption for Midland PUC

			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2003	46,627,475		47,506,016	
2004	46,604,134	-0.1%	48,173,337	1.4%
2005	48,370,214	3.8%	49,030,057	1.8%
2006	46,479,977	-3.9%	49,691,247	1.3%
2007	47,886,438	3.0%	49,444,280	-0.5%
2008F			49,640,491	0.4%
2009F			49,791,737	0.3%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2003	27,036,581		27,650,878	
2004	26,788,352	-0.92%	27,685,847	0.1%
2005	26,768,115	-0.08%	27,650,878	-0.1%
2006	25,943,176	-3.08%	27,650,878	0.0%
2007	27,070,448	4.35%	27,685,847	0.1%
2008F			27,668,362	-0.1%
2009F			27,650,878	-0.1%

2.2 NON-WEATHER SENSITIVE CLASS FORECASTS

Historic and forecast class consumption for non-weather sensitive classes (GS>50 kW, Street Lighting, Sentinel Lighting, and USL) are displayed in Table 7 below. Class kW forecast values (where applicable) are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values are based on the kW/kWh ratio in 2007. Forecasts are based on the trend of consumption over the past two historic years (2006 and 2007), except for USL and sentinel lighting, which are held flat at the 2007 level. The sentinel light class saw a drop in consumption and connections due to the loss of 2 accounts (for a total of 11 connections). No change in connections or accounts is anticipated going forward from 2007.

Table 7 – GS>50 kW Class, Street & Sentinel Lighting, and USL

	GS > 50				*Street Lighting*			
Year	kWh	%	kW	%	kWh	%	kW	%
2003	148,856,264		390,472					
2004	152,507,009	2.5%	385,769	-1.2%	1,254,703		2,841	
2005	156,958,340	2.9%	370,122	-4.1%	1,100,219	-12.3%	3,111	9.5%
2006	152,154,878	-3.1%	362,602	-2.0%	1,111,104	1.0%	3,130	0.6%
2007	147,933,603	-2.8%	352,976	-2.7%	1,146,938	3.2%	2,927	-6.5%
2008F	143,617,885	-2.9%	342,678	-2.9%	1,171,106	2.1%	2,989	2.1%
2009F	139,428,070	-2.9%	332,681	-2.9%	1,195,783	2.1%	3,052	2.1%

	Sentinel Lighting				*USL*	
Year	kWh	%	kW	%	kWh	%
2003	34,979		90			
2004	53,430	52.7%	110	52.7%		
2005	42,992	-19.5%	104	-19.5%		
2006	25,367	-41.0%	67	-40.7%		
2007	15,948	-37.1%	44	-37.2%	513,550	
2008F	15,948	0.0%	44	0.0%	513,550	
2009F	15,948	0.0%	44	0.0%	513,550	

Table 8 below presents the results for class specific historic actual and historic normalized (2007) kWh and kW (where applicable), and normalized forecast values for bridge year (2008) and test year (2009).

Table 8 – Load Forecast (Historical, Bridge and Test Years).

	2007 Actual	2007 Normalized	2008f Normalized	2009f Normalized
Residential (kWh)	47,886,438	49,444,280	49,640,491	49,791,737
GS<50 (kWh)	27,070,448	27,685,847	27,668,362	27,650,878
GS>50 (kWh)	147,933,603	147,933,603	143,617,885	139,428,070
(kW)	352,976	352,976	342,678	332,681
Street Lights (kWh)	1,146,938	1,146,938	1,171,106	1,195,783
(kW)	2,927	2,927	2,989	3,052
Sentinel Lights (kWh)	15,948	15,948	15,948	15,948
(kW)	44	44	44	44
USL (kWh)	513,550	513,550	513,550	513,550
Total Retail kWh	224,566,924	226,740,165	222,627,341	218,595,965

Historic customer figures on an average annual basis are presented in Table 12 below. Table 12 also provides a trend forecast for the number of customers in each rate class for 2008 and 2009. Trend is calculated based on the most recent 2 years of growth. No trend is used for USL.

Table 12 – Average Annual Customer Connections – Midland PUC

	Residential	%chg	GS<50	%chg	GS>50	%chg	Street Light	%chg	Sent Light	%chg	USL
2003	5,534	0.1%	695	0.8%	115	0.7%	1,384	0.0%	20		0
2004	5,556	0.4%	717	3.2%	115	-0.1%	1,469	6.1%	38	86.5%	0
2005	5,656	1.8%	716	-0.1%	111	-2.8%	1,487	1.2%	33	-12.5%	0
2006	5,746	1.6%	714	-0.4%	106	-4.9%	1,523	2.4%	26	-21.4%	0
2007	5,834	1.5%	722	1.2%	107	0.9%	1,525	0.1%	22	-15.7%	12
2005-2007		**1.6%**		**0.4%**		**-2.0%**		**1.3%**		**-18.5%**	
2008f	**5,925**		**726**		**105**		**1,544**		**22**		**12**
2009f	**6,018**		**729**		**103**		**1,564**		**22**		**12**

Explanation of Causes and Assumptions for the Volume Forecast

MPUC is a mature urban LDC which services approx. 6700 customers in the Town of Midland. Of these customers the residential class comprises 21.3% of total kWh load, GS<50 comprises 12.0% of the total kWh load, GS>50 comprises 65.9% of the total kWh load. Street Light, Sentinel Light and USL loads together total less than 1% of MPUC's load.

MPUC's GS>50 class is comprised of a relatively low number of customers (107 in 2007) although 65.9% of sales arise from this class. In the past two years, MPUC has dealt with the bankruptcies of two GS>50 class interval metered customers. One has remained in operation, yet consumption has decreased while the second has ceased operations completely, and the plant currently sits vacant. A large number of MPUC's GS>50 class customers are closely connected to the automotive industry. Midland has also experienced the closing of one primary school, although minor additions/upgrades have been added to two others.

MPUC's residential class over the past 5 years has experienced growth of less than 2% annually. The low growth rate indicates that Midland has a limited supply of available land for development. Residential growth in the past 5 years has consisted of small developments with approx. 15 – 25 homes per development, and backfilling of vacant lots throughout the Town. The GS<50 class also shows very little growth over the past 5 years, and this trend is expected to continue into the future. No strip malls, or commercial development is expected in 08 or 09. Midland has several vacant commercial properties with no consumption, although owners have not requested to have the meters disconnected.

In the spring of 2006 Third Tranche funding was used by MPUC to convert approximately 90 streetlights from incandescent to high pressure sodium blubs throughout the Town, in an effort to conserve energy. As a result KW demand has decreased over the 2006 values. MPUC also delivered 7000 CFL lightbulbs to residential and commercial customers in 2006. The influence of Third Tranche CDM funding on consumption has been taken into account, as historical data from 2006 and 2007 which included this funding, was used in the forecasting of 2008 and 2009 data.

In 2007 and 2008 MPUC has partnered with the Ontario Power Authority in offering conservation programs to residential, GS<50 and GS>50 class customers. These programs included the Great Refrigerator Round-up, Peak Saver, ERIP and Summer Savings programs. The influence of OPA funding on consumption has been taken into account as historical data from 2007 which included the above noted programs, was used in the forecasting of 2008 and 2009 data.

Normalized Volume Forecast Table

The following table presents 2007 Historical, 2008 Bridge Year and 2009 Test Year weather normalized forecast average annual consumption, and weather normalized forecast annual demand by class, for MPUC.

Table 27 Weather Normalized Forecast Average Annual Consumption And Demand

Class	2007 Normalized Data	2008 Normalized Forecast	2009 Normalized Forecast
Residential – kWh	49,444,280	49,640,491	49,791,737
Percent Change		*0.40%*	*0.30%*
GS<50 – kWh	27,685,847	27,668,362	27,650,878
Percent Change		*-0.06%*	*-0.06%*
GS>50 – kWh	147,933,603	143,617,885	139,428,070
Percent Change		*-2.92%*	*-2.92%*
GS>50 – KW	352,976	342,678	332,681
Percent Change		*-2.92%*	*-2.92%*
Street Lighting – kWh	1,146,938	1,171,106	1,195,783
Percent Change		*2.11%*	*2.11%*
Street Lighting – KW	2,927	2,989	3,052
Percent Change		*2.12%*	*2.11%*
Sentinel Lighting - kWh	15,948	15,948	15,948
Percent Change		*0.00%*	*0.00%*
Sentinel Lighting – KW	44	44	44
Percent Change		*0.00%*	*0.00%*
USL – kWh	513,550	513,550	513,550
Percent Change		*0.00%*	*0.00%*
Total – kWh	226,740,166	222,627,342	218,595,966
Total – KW	355,947	345,711	335,777

Customer Count Forecast Table

The following table presents historical and forecast average annual customer/connection numbers, by class, for MPUC. Street Lighting and Sentinel Lighting numbers represent the number of connections. Annual percentage changes are presented for all classes based on the average number of customers in each class per year. The annual trend growth rate is used to project customer growth/decline into the 2008 Bridge and 2009 Test Year. A trend forecast for the number of customers in each rate class for the 2008 Bridge and 2009 Test Year is calculated based on the most recent 2 years of growth. No trend was used for the Sentinel Lighting and USL class as these numbers are not expected to change in the next two years.

Table 28 MPUC Customer Forecast Table

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	*2007 Actual*	*2008 Forecast*	*2009 Forecast*
Residential	5,534	5,556	5,656	5,746	5,834	5,925	6,018
Percent Change	0.1%	0.4%	1.8%	1.6%	1.5%	1.6%	1.6%
GS < 50kW	695	717	716	714	722	726	729
Percent Change	*0.8%*	*3.2%*	*-0.1%*	*-0.4%*	*1.2%*	*0.4%*	*0.4%*
GS > 50	115	115	111	106	107	105	103
Percent Change	*0.7%*	*-0.1%*	*-2.8%*	*-4.9%*	*0.9%*	*-2.0%*	*-2.0%*
Street Lighting	1384	1469	1487	1523	1525	1544	1564
Percent Change	*0.00%*	*6.1%*	*1.2%*	*2.4%*	*0.1%*	*1.3%*	*1.3%*
Sentinel Lighting	20	38	33	26	22	22	22
Percent Change		*86.5%*	*-12.5%*	*-21.4%*	*-15.7%*	*0.00%*	*0.00%*
USL	0	0	0	0	12	12	12
Percent Change						*0.00%*	*0.00%*
Total	7,748	7,895	8,003	8,115	8,222	8,334	8,448

MPUC has limited growth for both residential and GS<50 classes. The GS>50 class contains only a handful of customers, and the numbers have been steadily declining. For the GS>50 class an annual declining rate of approx. 2.0% was assumed for the 2008 Bridge and 2009 Test Year.

Customer numbers for Sentinel Lighting and USL classes are not expected to change over the 2008 Bridge and 2009 Forecast Years. The sentinel light class saw a drop in the number of connections as a result of the transfer of accounts to the GS<50 class after meters were installed. MPUC does not expect the number of Sentinel Light and USL class connections to change in the next few years.

Historical Average Consumption

Listed below are tables representing historical actual and historical normalized consumption for the years 2003 to 2007 and forecast normalized annual consumption and demand (where applicable) for the 2008 Bridge and 2009 Test Years per class of customer with MPUC.

Residential Class

The following table presents historical actual and historical normalized consumption for the years 2003 to 2007, and forecast normalized annual consumption for the 2008 Bridge and 2009 Test Years for Residential Customers.

Table 29 Residential Actual And Normalized Consumption

Year	Actual Residential kWh	Weather Normal kWh
2003	46,627,475	47,506,016
2004	46,604,134	48,173,337
Per Cent Change	*-0.01%*	*1.4%*
2005	48,370,214	49,030,057
Per Cent Change	*3.8%*	*1.8%*
2006	46,479,977	49,691,247
Per Cent Change	*-3.9%*	*1.3%*
2007	47,886,438	49,444,280
Per Cent Change	*3.0%*	*-0.5%*
2008 – Forecast		49,640,491
Per Cent Change		*0.4%*
2009 – Forecast		49,791,737
Per Cent Change		*0.3%*

MPUC's residential class has shown limited growth over the past 5 years with increases of less than 2% annually, which is reflective in the consumption numbers above. In 2007 MPUC partnered with the OPA in offering the Appliance Retirement, Summer Savings and PeakSaver conservation programs to residential customers. 2007 was the first year for these programs, which may help to explain the 0.497% reduction in 2007 weather normalized kWh consumption.

GS<50 Class

The following table presents historical actual and historical normalized consumption for the years 2003 to 2007, and forecast normalized annual consumption for the 2008 Bridge and 2009 Test Years for GS<50 Customers.

Table 30 General Service (<50 kW) Actual And Normalized Consumption

Year	Actual GS<50 kWh	Weather Normal kWh
2003	27,036,581	27,650,878
2004	26,788,352	27,685,847
Per Cent Change	*-0.92%*	*0.1%*
2005	26,768,115	27,650,878
Per Cent Change	*-0.08%*	*-0.1%*
2006	25,943,176	27,650,878
Per Cent Change	*-3.08%*	*0.0%*
2007	27,070,448	27,685,847
Per Cent Change	*4.35%*	*0.1%*
2008 – Forecast		27,668,362
Per Cent Change		*-0.1%*
2009 – Forecast		27,650,878
Per Cent Change		*-0.1%*

MPUC's GS<50 class has also shown minimal growth over the past 5 years, which is reflective in the consumption numbers above. This trend is expected to continue into the future with a less than 1% decrease in future consumption, as no additional commercial development is expected in 08 or 09.

GS>50 Class

The following table presents historical and forecast consumption and demand for the non-weather sensitive GS>50 class. The GS>50 kWh forecast was based on the trend of consumption over the past two historic years (2006 and 2007). GS>50 KW forecast values are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values are based on the kW/kWh ratio in 2007 and are based on the trend of consumption over the past two historic years (2006 & 2007).

Table 31 General Service (>50 kW) Actual And Forecast Consumption

Year	kWh Consumption	KW Demand
2004	152,507,009	385,769
2005	156,958,340	370,122
Per Cent Change	*2.9%*	*-4.1%*
2006	152,154,878	362,602
Per Cent Change	*-3.1%*	*-2.0%*
2007	147,933,603	352,976
Per Cent Change	*-2.8%*	*-2.7%*
2008 – Forecast	143,617,885	342,678
Per Cent Change	*-2.9%*	*-2.9%*
2009 – Forecast	139,428,070	332,681
Per Cent Change	*-2.9%*	*-2.9%*

MPUC's GS>50 class is comprised by a relatively low number of customers (107 in 2007), and customer numbers in this class have been declining steadily over the past 5 years. In the past two years, MPUC has dealt with the bankruptcies of two GS>50 class interval metered customers. One has remained in operation, yet consumption has decreased while the second has ceased operations completely, and the plant currently sits vacant. In addition, several of MPUC's larger GS>50 customers are closely connection to the automotive industry. Midland has also experienced the closing of one primary school, although minor additions/upgrades have been added to two others.

Street Lighting Class

The following table presents historical and forecast consumption and demand for the non-weather sensitive Street Lighting class. The Street Light kWh forecast was based on the trend of consumption over the past two historic years (2006 and 2007). Street Lighting KW forecast values are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values are based on the kW/kWh ratio in 2007 and are based on the trend of consumption over the past two historic years (2006 & 2007).

Table 32 Street Lighting Class Actual And Forecast Consumption

Year	kWh Consumption	KW Demand
2005	1,100,219	3,111
2006	1,111,104	3,130
Per Cent Change	*1.0%*	*0.6%*
2007	1,146,938	2,927
Per Cent Change	*3.2%*	*-6.5%*
2008 – Forecast	1,171,106	2,989
Per Cent Change	*2.1%*	*2.1%*
2009 – Forecast	1,195,783	3,052
Per Cent Change	*2.1%*	*2.1%*

In the spring of 2006 Third Tranche funding approved by the Ontario Energy Board was used by MPUC to converted approximately 90 Street Lights from incandescent to high pressure sodium blubs throughout the Town of Midland, in an effort to conserve energy. As a result KW demand for 2007 has decreased over the 2006 values.

Sentinel Lighting Class

The following table presents historical and forecast consumption and demand for the non-weather sensitive Sentinel Lighting class. Sentinel Lighting KW forecast values are calculated by determining an annual kW/kWh ratio and multiplying this ratio by the forecast kWh in the year. Forecast values remain flat and are based on the kW/kWh ratio in 2007.

Table 33 Sentinel Lighting Class Actual And Forecast Consumption

Year	kWh Consumption	KW Demand
2003	34,979	90
2004	53,430	110
Per Cent Change	*52.7%*	*52.7%*
2005	42,992	104
Per Cent Change	*-19.5%*	*-19.5%*
2006	25,367	67
Per Cent Change	*-41.0%*	*-40.7%*
2007	15,948	44
Per Cent Change	*-37.1%*	*-37.2%*
2008 – Forecast	15,948	44
Per Cent Change	*0.00%*	*0.00%*
2009 – Forecast	15,948	44
Per Cent Change	*0.00%*	*0.00%*

Consumption amounts for the Sentinel Lighting class are not expected to change over the 2008 Bridge and 2009 Forecast Years. The sentinel light class saw a drop in the number of connections as a result of the transfer of accounts to the GS<50 class after meters were installed. MPUC does not expect the number of Sentinel Light class connections to change in the next few years.

Unmetered Scattered Load (USL) Class

The following table presents historical and forecast consumption for the non-weather sensitive Unmetered Scattered Load (USL) class.

Table 34 USL Actual And Forecast Consumption

Year	kWh Consumption
2007	513,550
2008 – Forecast	513,550
Per Cent Change	*0.00%*
2009 – Forecast	513,550
Per Cent Change	*0.00%*

USL class data was only available from 2007, as this class was previously included in the GS<50 class. Forecast kWh for the 2008 Bridge and 2009 Test Years were based on the 2007 actual data and have remained flat, as the number of customers and consumption amounts for this class are not expected to change for the forecast years.

Other Revenue

Other Distribution Revenue

Exhibit 3, Tab 1, Schedule 2 included a Summary of Distribution Revenue Table. This table provided details of Distribution Revenue and details of the Other Distribution Revenue for the 2006 EDR, the 2006 Actual Year, the 2007 Actual Year, the 2008 Bridge Year and the 2009 Bridge Year. This section will discuss the Other Distribution Revenue. The table is reproduced on the following page.

Summary of Distribution Revenue Table

Distribution Revenue	2009 @ new rates	2008 Projection	Var $	2008 Projection	2007 Actual	Var $	2007 Actual	2006 Actual	Var $	2006 Actual	2006 EDR Approved	Var $
Residential	1,901,008	1,772,803	128,205	1,772,803	1,682,252	90,551	1,682,252	1,661,132	21,120	1,661,132	1,645,983	15,149
General Service <50 kW	604,986	494,950	110,036	494,950	462,027	32,923	462,027	432,680	29,346	432,680	479,219	-46,539
General Service >50kW	1,472,170	810,606	661,564	810,606	719,776	90,830	719,776	727,854	-8,078	727,854	922,724	-194,870
Street Lighting	73,446	24,879	48,567	24,879	24,224	655	24,224	23,509	715	23,509	24,260	-751
Sentinel Lighting	5,574	501	5,073	501	376	125	376	676	-300	676	2,231	-1,555
Unmetered Scattered Load	16,252	8,968	7,284	8,968	10,106	-1,138	10,106	8,089	2,017	8,089		8,089
Gross Revenue (before Transformer Allowance)	4,073,436	3,112,707	960,729	3,112,707	2,898,761	213,946	2,898,761	2,853,941	44,820	2,853,941	3,074,417	-220,476
Transformer Allowance	-151,200	-151,200	0	-151,200	-147,658	-3,542	-147,658	-153,029	5,371	-153,029	-161,825	8,796
Total Revenue	3,922,236	2,961,507	960,729	2,961,507	2,751,103	210,404	2,751,103	2,700,912	50,191	2,700,912	2,912,592	-211,680
Less: Low voltage charges embedded in distribution rates	-339,515	-268,609	-70,906	-268,609	-95,602	-173,007	-95,602	-67,613	-27,989	-67,613	-284,777	217,164
DISTRIBUTION REVENUE	**3,582,721**	**2,692,898**	**889,823**	**2,692,898**	**2,655,501**	**37,397**	**2,655,501**	**2,633,299**	**22,202**	**2,633,299**	**2,627,815**	**5,484**

Other Distribution Service Revenue	2009 @ new rates	2008 Projection	Var $	2008 Projection	2007 Actual	Var $	2007 Actual	2006 Actual	Var $	2006 Actual	2006 EDR Approved	Var $
4080-Distribution Services Revenue	15,825	15,825	-0	15,825	15,831	-6	15,831	16,271	-440	16,271	129,402	-113,131
4090-Electric Services Incidental to Energy Sales	0	0	0	0	0	0	0		0		16,205	-16,205
4210-Rent from Electric Property	82,481	82,481	0	82,481	81,661	819	81,661	88,519	-6,858	88,519	56,499	32,020
4220-Other Electric Revenues	0	0	0	0	2,110	-2,110	2,110	1,315	795	1,315	354	961
4225-Late Payment Charges	10,000	10,000	0	10,000	8,121	1,879	8,121	13,730	-5,609	13,730	24,085	-10,355
4230-Sales of Water and Water Power	0	0	0	0	0	0	0	0	0	0	16,605	-16,605
4235-Miscellaneous Service Revenues	91,625	91,625	0	91,625	93,477	-1,852	93,477	81,660	11,817	81,660	18,399	63,261
4325-Revenues from Merchandise, Jobbing, Etc.	82,000	82,000	0	82,000	78,471	3,529	78,471	57,136	21,335	57,136	175,024	-117,888
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	-60,800	-60,800	0	-60,800	-47,624	-13,176	-47,624	-37,329	-10,295	-37,329	-139,514	102,185
4355-Gain on Disposition of Utility and Other Property	0	0	0	0	36,734	-36,734	36,734	1,040	35,694	1,040	0	1,040
4405-Interest and Dividend Income	10,000	30,000	-20,000	30,000	74,750	-44,750	74,750	62,682	12,068	62,682	33,250	29,432
TOTAL OTHER DISTRIBUTION SERVICE REVENUE	**231,131**	**251,131**	**-20,000**	**251,131**	**343,533**	**-92,402**	**343,533**	**285,024**	**58,509**	**285,024**	**330,308**	**-45,284**
Distribution Revenues (see above)	**3,582,721**	**2,692,898**	**889,823**	**2,692,898**	**2,655,501**	**37,397**	**2,655,501**	**2,633,299**	**22,202**	**2,633,299**	**2,627,815**	**5,484**
TOTAL DISTRIBUTION REVENUES	**3,813,852**	**2,944,029**	**869,823**	**2,944,029**	**2,999,034**	**-55,005**	**2,999,034**	**2,918,323**	**80,710**	**2,918,323**	**2,958,123**	**-39,800**

Materiality Analysis on Other Distribution Revenue

The following analysis discusses the variances over the materiality threshold. This threshold is calculated as 1% of total 2006 EDR Board Approved revenue requirement (1% x $2,629,071) net of low voltage charges = $26,291.

The following analysis compares the Other Distribution Revenue Accounts for the 2006 EDR, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years. Those variances over the $26,291 shown above are explained.

2006 Actual vs. 2006 EDR

Table 35 Other Distribution Revenues (2006)

Account # and Name	Actual - 2006	EDR – 2006	Variance
4080 – Distribution Services Revenue	$ 16,271	$129,402	-$113,131
4090- Electric Services Incidental to Energy Sales	$ 0	$ 16,205	-$ 16,205
4210 – Rent from Electric Property	$ 88,519	$ 56,499	$ 32,020
4220 – Other Electric Revenues	$ 1,315	$ 354	$ 961
4225 – Late Payment charges	$ 13,730	$ 24,085	-$ 10,355
4230 – Sales of Water & Water Power	$ 0	$ 16,605	-$ 16,605
4235 – Miscellaneous Service Revenues	$ 81,660	$ 18,399	$ 63,261
4325 – Revenues from Merch, Jobbing	$ 57,136	$175,024	-$117,888
4330 – Costs & Exp from Merch. Jobbing	-$ 37,329	-$139,514	$102,185
4355 – Gain on Disposition of Utility Ppty	$ 1,040	$ 0	$ 1,040
4405 – Interest & Dividend Income	$ 62,682	$ 33,250	$ 29,432
Total Other Distribution Revenue	$285,024	$ 330,308	- $ 45,284
Threshold -1% of 2006 EDR base rev. req.	$26,291	$26,291	

Variances greater than $26,291 are explained as follows:

Account # & Name	2006 Actual	2006 EDR	Variance
4080 – Distribution Services Revenue	**$ 16,271**	**$129,402**	**-$113,131**
2004 Actuals vs. 2006 EDR			$129.402
2006 RPP Administration Charge			-$ 16,271
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. The variance of $129.402 results from the difference between the calculation of Distribution Revenue at the EDR approved rates vs. the 2004 actual data. 2004 Distribution Revenue totalled $2,757,216 vs. the 2006 EDR of $2,627.815. The 2006 EDR required MPUC to transfer the RPP Administration Charge of $.25 per account per month (total $16,205) to USoA #4090. In 2006, the RPP Administration Charge was posted to USoA #4080 in the amount of $16,271.

Account # & Name	2006 Actual	2006 EDR	Variance
4210-Rent from Electric Property	**$ 88,519**	**$ 56,499**	**$ 32,020**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. The increase in revenues for actual 2006 is due to an increase in rental fees as well as an increase in pole rental.

Account # & Name	2006 Actual	2006 EDR	Variance
4235 – Miscellaneous Service Revenues	**$ 81,660**	**$ 18,399**	**$ 63,261**
Cost Drivers:			
Notification Charge – increase			-$39,120
Account Set-up Charge; Disconnection Charges; Account History; Returned Cheque; Legal Letter Charge – increase			-$24,141
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. In 2006, MPUC's miscellaneous revenues increased primarily as a result of the Notification Charge of $39,120 paid by customers who receive a hand delivered letter as a result of non-payment of their account. This charge was not paid in 2004 and came into effect on May 1, 2006. Account Set-up Charge increased from $15 to $30 on May 1, 2006; Disconnection Charges increased from $20 to $65 on May 1, 2006; Account History Charges increased from $5 to $15 on May 1, 2006; Returned Cheque Charges increased from $9 to $15 on May 1, 2006 and we were approved for collection of Legal Letter Charges of $15 on May 1, 2006. All of these additional charges would account for the increase in the variance of $24,141.

Account # & Name	**2006 Actual**	**2006 EDR**	**Variance**
4325-Revenues from Merchandise, Jobbing,	**$ 57,136**	**$175,024**	**$117,888**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. Due to inadvertence, in 2004 all revenues from merchandising and jobbing were recorded as income and were not recorded as contributed capital. Expenses were allocated from OM&A Expenses and were deducted from the revenues recorded in Merchandising and Jobbing. In 2006, contributed capital jobs were recorded properly in the appropriate capital asset accounts in accordance with the APH.

Account # & Name	**2006 Actual**	**2006 EDR**	**Variance**
4330-Costs&Expenses of Merchandising, Jobbing	**$ 37,329**	**$139,514**	**$102,185**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. As mentioned above, due to inadvertence, in 2004 all revenues from merchandising and jobbing were recorded as income and were not recorded as contributed capital. Expenses were allocated from OM&A Expenses and were deducted from the revenues recorded in

Merchandising and Jobbing. In 2006, contributed capital jobs were recorded properly in the appropriate capital asset accounts in accordance with the APH.

Account # & Name	2006 Actual	2006 EDR	Variance
4405 – Interest & Dividend Income	**$ 62,682**	**$ 33,250**	**$ 29,432**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. Interest earned on bank balances increased in 2006 over those amounts recorded in the 2006 EDR.

Reconciliation to Other Distribution Revenues Table:

Variances exceeding the materiality threshold of $26,291 have been explained above. Those variances less than the materiality of $26,291 represent increases/decreases to the Other Distribution Revenue USoA numbers as follows:

Account # and Name	Actual - 2006	EDR – 2006	Variance
4090- Electric Services Incidental to Energy Sales	**$ 0**	**$ 16,205**	**-$ 16,205**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. The 2006 EDR required MPUC to transfer the RPP Administration Charge of $.25 per account per month (total $16,205) to USoA #4090. In 2006, the RPP Administration Charge was posted to USoA #4080 in the amount of $16,271.

Account # and Name	Actual - 2006	EDR – 2006	Variance
4220 – Other Electric Revenues	**$ 1,315**	**$ 354**	**$ 961**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. In 2006, MPUC revenues increased due to the sale of scrap.

Account # and Name	**Actual - 2006**	**EDR – 2006**	**Variance**
4225 – Late Payment charges	**$ 13,730**	**$ 24,085**	**-$ 10,355**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. Late Payment charges reduced in 2006 in comparison to the 2004 balances.

Account # and Name	**Actual - 2006**	**EDR – 2006**	**Variance**
4230 – Sales of Water & Water Power	**$ 0**	**$ 16,605**	**-$ 16,605**

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. In accordance with the requirements of the EDR filing, MPUC recorded pole rental in account #4230.

Account # and Name	**Actual - 2006**	**EDR – 2006**	**Variance**
4355 – Gain on Disposition of Utility Ppty	**$ 1,040**	**$ 0**	**$ 1,040**

Explanation:

The gain on sale of utility property in 2006 represents the proceeds from the sale of two pickup

2007 Actual to 2006 Actual

Table 36 Other Distribution Revenue (2007)

Account # and Name	Actual - 2007	Actual - 2006	Variance
4080 – Distribution Services Revenue	$ 15,831	$ 16,271	-$ 440
4090- Electric Services Incidental to Energy Sales	$ 0	$ 0	-$ 0
4210 – Rent from Electric Property	$ 81,661	$ 88,519	-$ 6,858
4220 – Other Electric Revenues	$ 2,110	$ 1,315	$ 795
4225 – Late Payment charges	$ 8,121	$ 13,730	-$ 5,609
4230 – Sales of Water & Water Power	$ 0	$ 0	-$ 0
4235 – Miscellaneous Service Revenues	$ 93,477	$ 81,660	$ 11,817
4325 – Revenues from Merch, Jobbing	$ 78,471	$ 57,136	$ 21,335
4330 – Costs & Exp from Merch. Jobbing	-$ 47,624	-$ 37,329	-$ 10,295
4355 – Gain on Disposition of Utility Ppty	$ 36,734	$ 1,040	$ 35,694
4405 – Interest & Dividend Income	$ 74,750	$ 62,682	$ 12,068
Total Other Distribution Revenue	$343,533	$285,024	$ 58,509
Threshold -1% of 2006 EDR base rev. req.	$26,291	$26,291	

Variances greater than the materiality of $26,291 are explained as follows:

Account # & Name	2007 Actual	2006 Actual	Variance
4355 – Gain on Disposition of Utility Ppty	**$ 36,734**	**$ 1,040**	**$ 35,694**

Explanation:

In 2007, MPUC purchased new vehicles. All vehicles in use at the time of the purchase of the new vehicles were fully depreciated. The gain on disposal of the vehicles in use represents the trade-in allowance on the trade in of vehicles at the time of the purchase. In addition, the vehicles disposed of in 2006 were traded in and a trade-in allowance was inadvertently netted with the cost of the new vehicle. In 2007 an adjustment was done to record the new vehicle at the actual cost and record the gain on the trade-in.

Reconciliation to Other Distribution Revenues Table:

Variances exceeding the materiality threshold of $26,291 have been explained above. Those variances less than the materiality of $26,291 represent increases/decreases to the Other Distribution Revenue USoA numbers as follows:

Account # and Name	2007 Actual	2006 Actual	Variance
4080 – Distribution Services Revenue	**$ 15,831**	**$ 16,271**	**-$ 440**

Explanation:

RPP Administration Charges reduced by $440 from the 2006 year. Fluctuations in customer numbers due to the transfer to retailer contracts and customer relocations during the year would account for the variance.

Account # and Name	2007 Actual	2006 Actual	Variance
4210 – Rent from Electric Property	**$ 81,661**	**$ 88,519**	**-$ 6,858**

Explanation:

Rental from buildings decreased in 2007 by $6,858 due to less space being rented by our tenant.

Account # and Name	2007 Actual	2006 Actual	Variance
4220 – Other Electric Revenues	**$ 2,110**	**$ 1,315**	**$ 795**

Explanation:

Other revenues increased over 2006 due to the sale of additional scrap materials.

Account # and Name	2007 Actual	2006 Actual	Variance
4225 – Late Payment charges	**$ 8,121**	**$ 13,730**	**-$ 5,609**

Explanation:

Late Payment charges have decreased over 2006 levels, due in part to the additional charges imposed in 2006 for disconnection notices. Customers on the whole are becoming more aware of the fees and charges as a result of non-payment of accounts.

Account # and Name	2007 Actual	2006 Actual	Variance
4235 – Miscellaneous Service Revenues	**$ 93,477**	**$ 81,660**	**$ 11,817**

Explanation:

As a result of the increase in Service Revenue charges (notification charge, account set up charge, etc) in the 2006 EDR, Service Revenues in 2007 increased over 2006. These charges came into effect in May of 2006. Consequently, 2007 was the first full year for the new charges.

Account # and Name	2007 Actual	2006 Actual	Variance
4325 – Revenues from Merch, Jobbing	**$ 78,471**	**$ 57,136**	**$ 21,335**

Explanation:

Revenues from jobbing increased over 2006 levels. Additional work was performed by MPUC which accounts for the increase.

Account # and Name	2007 Actual	2006 Actual	Variance
4330 – Costs & Exp from Merch. Jobbing	**-$ 47,624**	**-$ 37,329**	**-$ 10,295**

Explanation:

Along with the increase in revenues from jobbing, MPUC would then incur additional expenses.

Account # and Name	2007 Actual	2006 Actual	Variance
4405 – Interest & Dividend Income	**$ 74,750**	**$ 62,682**	**$ 12,068**

Explanation:
MPUC earned additional interest in 2007 over 2006 levels. This interest is earned on our bank account balances.

2008 Bridge Year to 2007 Actual Year

Table 37 Other Distribution Revenue (2008)

Account # and Name	2008 Bridge	Actual - 2007	Variance
4080 – Distribution Services Revenue	$ 15,825	$ 15831	$ 6
4090- Electric Services Incidental to Energy Sales	$ 0	$ 0	-$ 0
4210 – Rent from Electric Property	$ 82,481	$ 81,661	$ 819
4220 – Other Electric Revenues	$ 0	$ 2,110	-$ 2,110
4225 – Late Payment charges	$ 10,000	$ 8,121	$ 1,879
4230 – Sales of Water & Water Power	$ 0	$ 0	-$ 0
4235 – Miscellaneous Service Revenues	$ 91,625	$ 93,477	-$ 1,852
4325 – Revenues from Merch, Jobbing	$ 82,000	$ 78,471	$ 3,529
4330 – Costs & Exp from Merch. Jobbing	-$ 60,800	-$ 47,624	-$ 13,176
4355 – Gain on Disposition of Utility Ppty	$ 0	$ 36,734	-$ 36,734
4405 – Interest & Dividend Income	$ 30,000	$ 74,750	-$ 44,750
Total Other Distribution Revenue	$251,131	$343,533	-$ 92,402
Threshold -1% of 2006 EDR base rev. req.	$26,291	$26,291	

Variances greater than the materiality of $26,291 are explained as follows:

Account # and Name	2008 Bridge	Actual - 2007	Variance
4355 – Gain on Disposition of Utility Ppty	**$ 0**	**$ 36,734**	**-$ 36,734**

Explanation:
In 2007, a gain on disposal of vehicles was realized on the trade-in value of old vehicles for new purchases. It is not expected that there will be any gains on disposition of MPUC property in 2008.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4405 – Interest & Dividend Income	**$ 30,000**	**$ 74,750**	**-$ 44,750**

Explanation:
As MPUC's capital program has increased over the years interest income will be reduced as bank balances are reduced by payments for capital projects. In addition, regulatory asset recoveries will cease in May, 2008. Consequently, cash flows will decrease as a result of the reduction in monies received from customers on account of regulatory asset balances.

Reconciliation to Other Distribution Revenues Table:
Variances exceeding the materiality threshold of $26,291 have been explained above. Those variances less than the materiality of $26,291 represent increases/decreases to the Other Distribution Revenue USoA numbers as follows:

Account # and Name	2008 Bridge	Actual - 2007	Variance
4080 – Distribution Services Revenue	**$ 15,825**	**$ 15,831**	**$ 6**

Account # and Name	2008 Bridge	Actual - 2007	Variance
4210 – Rent from Electric Property	**$ 82,481**	**$ 81,661**	**$ 819**

Explanation:
Rental from MPUC tenants is expected to increase in 2008.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4220 – Other Electric Revenues	**$ 0**	**$ 2,110**	**-$ 2,110**

Explanation:
MPUC does not expect to sell scrap materials in 2008.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4225 – Late Payment charges	**$ 10,000**	**$ 8,121**	**$ 1,879**

Explanation:

MPUC has projected $10,000 in late payment charges in 2008 which is $1,879 over 2007 levels.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4235 – Miscellaneous Service Revenues	**$ 91,625**	**$ 93,477**	**-$ 1,852**

Explanation:

MPUC is projecting a small decrease in Service Revenues in 2008.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4325 – Revenues from Merch, Jobbing	**$ 82,000**	**$ 78,471**	**$ 3,529**

Explanation:

MPUC is projecting that jobbing will increase over 2007 levels by $3,529.

Account # and Name	2008 Bridge	Actual - 2007	Variance
4330 – Costs & Exp from Merch. Jobbing	**-$ 60,800**	**-$ 47,624**	**-$ 13,176**

Explanation:

Along with the increase in revenues from jobbing, MPUC is projecting that economies in expenses will be attained in 2008 over 2007 levels.

2009 Test Year to 2008 Bridge Year

Table 38 Other Distribution Revenue (2009)

Account # and Name	2009 Test	2008 Bridge	Variance
4080 – Distribution Services Revenue	$ 15,825	$ 15,825	$ 0
4090- Electric Services Incidental to Energy Sales	$ 0	$ 0	$ 0
4210 – Rent from Electric Property	$ 82,481	$ 82,481	$ 0
4220 – Other Electric Revenues	$ 0	$ 0	$ 0
4225 – Late Payment charges	$ 10,000	$ 10,000	$ 0
4230 – Sales of Water & Water Power	$ 0	$ 0	$ 0
4235 – Miscellaneous Service Revenues	$ 91,625	$ 91,625	$ 0
4325 – Revenues from Merch, Jobbing	$ 82,000	$ 82,000	$ 0
4330 – Costs & Exp from Merch. Jobbing	-$ 60,800	-$ 60,800	$ 0
4355 – Gain on Disposition of Utility Ppty	$ 0	$ 0	$ 0
4405 – Interest & Dividend Income	$ 10,000	$ 30,000	-$ 20,000
Total Other Distribution Revenue	$231,131	$251,131	-$ 20,000
Threshold -1% of 2006 EDR base rev. req.	$26,291	$26,291	

No variances greater than the materiality of $26,291. The above variances represent increases/decreases to the Other Distribution Revenue USoA numbers as follows:

Account # and Name	2009 Test	2008 Bridge	Variance
4405 – Interest & Dividend Income	**$ 10,000**	**$ 30,000**	**-$ 20,000**

Explanation:

As MPUC's capital program has increased over the years interest income will be reduced as bank balances are reduced by payments for capital projects. In addition, regulatory asset recoveries will cease in May, 2008. Consequently, cash flows will decrease as a result of the reduction in monies received from customers on account of regulatory asset balances.

Rate of Return on Other Distribution Revenue

In this application, MPUC has applied for the same Specific Service Charges schedule previously approved in the 2008 Tariffs of Rates and Charges (EB-2007-0847). In addition, MPUC is applying for an additional service charge, Interval Meter Load Management Tool, in the amount of $25.00 per month to provide interval customers internet access to their consumption data. The Specific Service Charges schedule follows the OEB recommended charges and as such MPUC has no further information related to the rate of return on non-core delivery activities.

Distribution Revenue Data

The Calculation of Distribution Revenue Table is provided on the following page.

Calculation of Distribution Revenue Table

2006 EDR Approved	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge ***	**Distribution Revenue**
Residential	5,568	8,342	0	$0.0196		$11.01	1,645,983
General Service <50 kW	726	36,921	0	$0.0139		$12.24	479,219
General Service >50 Kw	129	1,267,176	3,046		$2.2942	$13.67	922,724
Street Lighting	1,469	886	2		$2.3515	$0.95	24,260
Sentinel Lighting	114	310	1		$2.6020	$1.45	2,231
Unmetered Scattered Load	0	0	0				0
Gross Revenue (before Transformer Allowances)							**3,074,416**
Transformer Allowances							-161,825
Total Revenue							**2,912,591**
Less: Low voltage charges embedded in distribution rates							-284,777
DISTRIBUTION REVENUE							**2,627,814**
** Excluding Smart Meter Rate Adder*							

2006 Actual	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge ***	**Distribution Revenue**
Residential	5,746	8,089	0	$0.0196		$11.01	1,670,169
General Service <50 kW	714	36,335	0	$0.0139		$12.24	465,482
General Service >50 Kw	106	1,435,423	3,421		$2.2942	$13.67	849,270
Street Lighting	1,523	730	2		$2.3515	$0.95	24,722
Sentinel Lighting	26	976	3		$2.6020	$1.45	627
Unmetered Scattered Load	0	0		$0.0139		$12.24	0
Gross Revenue (before Transformer Allowances)							**3,010,270**
Transformer Allowances							-153,029
Total Revenue							**2,857,241**
Less: Low voltage charges embedded in distribution rates							-67,613
DISTRIBUTION REVENUE							**2,789,628**
Note: Schedule is based on 12 months of consumption at May 1, 2006 rates. Actual 2006 Revenues are a combination of rates in effect May 1, 2006 and May 1, 2005.							
** Excluding Smart Meter Rate Adder*							

2007 Actual	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge ***	**Distribution Revenue**
Residential	5,834	8,208	0	$0.0198		$11.11	1,725,940
General Service <50 kW	722	37,494	0	$0.0140		$12.35	485,987
General Service >50 Kw	107	1,382,557	3,299		$2.3148	$13.79	834,775
Street Lighting	1,525	752	2		$2.3727	$0.96	24,513
Sentinel Lighting	22	725	2		$2.6254	$1.46	501
Unmetered Scattered Load	12	42,796	0	$0.0140		$12.35	8,968
Gross Revenue (before Transformer Allowances)							**3,080,684**
Transformer Allowances							-147,658
Total Revenue							**2,933,026**
Less: Low voltage charges embedded in distribution rates							-95,602
DISTRIBUTION REVENUE							**2,837,424**
Note: Schedule is based on 12 months of consumption at May 1, 2007 rates. Actual 2007 Revenues are a combination of rates in effect May 1, 2007 and May 1, 2006.							
** Excluding Smart Meter Rate Adder*							

2008 Projection	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge ***	**Distribution Revenue**
Residential	5,925	8,378	0	$0.0198	$0.0000	$11.11	1,772,803
General Service <50 kW	726	38,111	0	$0.0140	$0.0000	$12.35	494,950
General Service >50 Kw	105	1,367,789	3,264	$0.0000	$2.3148	$13.79	810,606
Street Lighting	1,544	758	2	$0.0000	$2.3727	$0.96	24,879
Sentinel Lighting	22	725	2	$0.0000	$2.6254	$1.46	501
Unmetered Scattered Load	12	42,796	0	$0.0140	$0.0000	$12.35	8,968
Gross Revenue (before Transformer Allowances)							**3,112,707**
Transformer Allowances							-151,200
Total Revenue							**2,961,507**
Less: Low voltage charges embedded in distribution rates							-268,609
DISTRIBUTION REVENUE							**2,692,898**
Note: Schedule is based on 12 months of consumption at May 1, 2008 rates.							
** Excluding Smart Meter Rate Adder*							

2009 Projection	**Customers (Connections)**	**kWh's per Customer (Connection)**	**kW's per Customer (Connection)**	**Dist. Rate per kWh**	**Dist. Rate per kW**	**Monthly Service Charge ***	**Distribution Revenue**
Residential	6,018	8,274	0	$0.0211	$0.0000	$11.81	1,901,008
General Service <50 kW	729	37,930	0	$0.0171	$0.0000	$15.09	604,986
General Service >50 Kw	103	1,353,671	3,230	$0.0000	$4.2097	$57.99	1,472,170
Street Lighting	1,564	765	2	$0.0000	$18.1614	$0.96	73,446
Sentinel Lighting	22	725	2	$0.0000	$117.9289	$1.46	5,574
Unmetered Scattered Load	12	42,796	0	$0.0282	$0.0000	$12.35	16,252
Gross Revenue (before Transformer Allowances)							**4,073,435**
Transformer Allowances							-151,200
Total Revenue							**3,922,235**
Less: Low voltage charges embedded in distribution rates							-339,515
DISTRIBUTION REVENUE							**3,582,720**
Note: Schedule is based on 12 months of consumption at May 1, 2009 rates.							
** Excluding Smart Meter Rate Adder*							

Revenue Sharing

Description of Revenue Sharing

MPUC does not engage in revenue sharing

EXHIBIT 4 - OPERATING COSTS

1

Overview

Overview of Operating Costs

Operating Costs

The operating costs presented in this exhibit represent the annual expenditures required to sustain MPUC's Operations.

OM&A Costs

The OM&A costs in this exhibit represent MPUC's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to MPUC's distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The proposed OM&A cost expenditures for the 2009 test year result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place.

Operating and maintenance costs have increased reflecting the impact of inflation and expected changes in costs and as a result of increased labour compliment and regulatory and safety requirements. These regulatory and safety requirements are changing the way MPUC does business. OM&A Expenses are expected to increase $384,405 or 22.5% in the 2009 Test Year over 2006 EDR. This increase would reduce to $244,405 or 14.3% if an increase in staffing levels and Rate Application costs were not required. It should be noted that the number of employees in the 2006 EDR, which was based on 2004 actual data totaled 16 and in 2009 MPUC's total compliment will be 16. The increase in management staffing levels recognizes that MPUC is responding to the regulatory/safety needs by moving towards increasing and improving business practices and processes. These improvements and upgrades to its business practices will pay benefits in the long run. Consequently, these increased requirements for regulatory oversight and safety legislation will require increased costs. MPUC will be undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. The management position will play an important role in the design and implementation of these replacements/enhancements.

MPUC has over the past five years made efficiency gains in the administration department in firstly, reducing the amount of staffing needs as a result of data entry duties. Electronic downloads directly into our billing system from the banking institutions have reduced the necessity of manual input into the CIS system. Secondly, the conversion to the Harris CIS billing system has also provided efficiencies as MPUC partners with other LDCs within the CHEC group work though the IT component of the system configuration. These types of process and system integration have reduced the need for data entry and billing personnel. Regulatory and safety requirements have however, increased the need for staff at a managerial level. Although MPUC has reduced the administrative cost of employees, we recognize the need to put more emphasis on the operational technical requirements for the safety and reliability of the distribution system.

Income Tax, Large Corporation Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Income Taxes paid by MPUC in 2006 totalled $496,000 for PILS and $4,000 for Capital Tax and in 2007 totalled $587,000 for PILS. The 2008 and 2009 tax liabilities are $13,836 and $204,993 respectively.

Summary of Operating Costs

Exhibit 4, Tab 2, Schedule 1 of this Application presents an analysis of Operating Costs for the 2006 EDR, the 2006 Year, the 2007 Year, the 2008 Bridge Year and the 2009 Test Year.

Exhibit 1, Tab 3, Schedule 1 of this Application includes a copy of the audited financial statements for MPUC as at December 31, 2006 by BDO Dunwoody, Chartered Accountants. A reconciliation of the 2006 Actual Operating Costs to the Audited Financial Statements of BDO is as follows:

Expenses Per Audited Financial Statements		**$2,351,469**
Add:	Capital Tax – recorded with PILS on Audited F/S	4,000
	Conservation & Demand Mgt Expense – Acct 5410	
	- recorded with Dist Revenue on Audited F/S	14,461
Less:	Contributed Capital inadvertently recorded with Other Revenues	-18,758
	Amortization	-497,831
	Interest	-50,159
Expenses per Exhibit 4, Tab 2, Schedule 1		**$1,803,182**

Exhibit 1, Tab 3, Schedule 2 of this Application includes a copy of the audited financial statements for MPUC as at December 31, 2007 by BDO Dunwoody, Chartered Accountants. A reconciliation of the 2007 Actual Operating Costs to the Audited Financial Statements of BDO is as follows:

Expenses Per Audited Financial Statements		**$2,345,304**
Add:	Conservation & Demand Mgt Expense – Acct 5410	
	- recorded with Dist Revenue on Audited F/S	8,398
Less:	Amortization	-523,913
	Interest	-44,789
Expenses per Exhibit 4, Tab 2, Schedule 1		**$1,785,000**

OM&A Costs

OM&A Costs Table

The OM&A costs in this Exhibit represents MPUC's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to MPUC's Distribution system, and to meet the service levels stipulated in the Standard Supply Service Code and the Retailer Settlement Codes.

The following analysis provides details of the OM&A Expense variances. These variances are shown in two tables, the OM&A Expense Summary Table and the Variance Analysis: Profit & Loss Detail Table.

The OM&A Expense Summary Table attached on the pages following this page shows the OM&A variances per Account Grouping as follows:

- 3500- Distribution Expenses – Operation
- 3550- Distribution Expenses – Maintenance
- 3650- Billing & Collecting
- 3700- Community Relations
- 3800- Administrative and General Expenses
- 3950- Taxes Other Than Income Taxes

The Variance Analysis: Profit & Loss Detail Table attached on the pages following the above OM&A Expense Summary Table, shows the variances per year per Account Grouping along with USoA APH Account Number descriptions. This table also provides revenue USoA APH variances, however, for the purposes of this analysis only OM&A Expense variances are discussed.

Both of these tables include expenses and variances for the 2006 EDR, 2006 Actual, 2007 Actual, 2008 Bridge and 2009 Test Years.

OM&A Expenses*

Account Grouping	2009 Projection	2008 Projection	Var $	2008 Projection	2007 Actual	Var $
3500-Distribution Expenses - Operation	455,700	392,900	**62,800**	392,900	352,987	**39,913**
3550-Distribution Expenses - Maintenance	353,900	338,200	15,700	338,200	283,582	**54,618**
3650-Billing and Collecting	435,800	420,400	15,400	420,400	451,821	**-31,421**
3700-Community Relations	5,600	5,700	-100	5,700	15,073	-9,373
3800-Administrative and General Expenses	807,900	744,600	**63,300**	744,600	650,232	**94,368**
3950-Taxes Other Than Income Taxes	34,200	32,900	1,300	32,900	31,306	1,594
TOTAL	**2,093,100**	**1,934,700**	**158,400**	**1,934,700**	**1,785,000**	**149,700**

** Operations, Maintenance & Administration*
Note: Variances in excess of the below-noted materiality threshold appear in ***bold***

Total Distribution Expenses		*2,556,881*			*2,308,914*	
Materiality Threshold			*25,569*			*23,089*

OM&A Expenses*

Account Grouping	2007 Actual	2006 Actual	Var $	2006 Actual	2006 EDR Approved	Var $
3500-Distribution Expenses - Operation	352,987	374,509	-21,521	374,509	272,722	**101,787**
3550-Distribution Expenses - Maintenance	283,582	336,041	**-52,459**	336,041	306,118	**29,923**
3650-Billing and Collecting	451,821	379,313	**72,507**	379,313	412,100	**-32,786**
3700-Community Relations	15,073	23,774	-8,701	23,774	15,581	8,193
3800-Administrative and General Expenses	650,232	655,050	-4,819	655,050	673,755	-18,705
3950-Taxes Other Than Income Taxes	31,306	34,495	-3,189	34,495	28,420	6,075
TOTAL	**1,785,000**	**1,803,182**	**-18,182**	**1,803,182**	**1,708,695**	**94,487**

** Operations, Maintenance & Administration*
Note: Variances in excess of the below-noted materiality threshold appear in ***bold***

Total Distribution Expenses		*2,301,014*			*2,144,658*	
Materiality Threshold			*23,010*			*21,447*

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var $	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	-2,890,308	-2,890,308		
	4025-Street Lighting Energy Sales	-69,413	-69,413		
	4030-Sentinel Lighting Energy Sales	-926	-926		
	4035-General Energy Sales	-9,728,401	-9,728,401		
	4062-Billed WMS	-1,443,364	-1,443,364		
	4066-Billed NW	-778,572	-778,572		
	4068-Billed CN	-1,427,036	-1,427,036		
	4075-Billed-LV	-339,515	-339,515	-0	(0.0%)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-3,598,546	-2,701,224	**-897,322**	**(33.2%)**
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-82,481	-82,481		
	4220-Other Electric Revenues				
	4225-Late Payment Charges	-10,000	-10,000		
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-91,625	-91,625		
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-82,000	-82,000		
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	60,800	60,800		
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-49,000	-49,000		
	4380-Expenses of Non-Utility Operations	21,000	21,000		
3200-Investment Income	4405-Interest and Dividend Income	-10,000	-10,000		
3350-Power Supply Expenses	4705-Power Purchased	12,689,048	12,689,048		
	4708-Charges-WMS	1,210,698	1,210,698		
	4710-Cost of Power Adjustments				
	4712-Charges-One-Time				
	4714-Charges-NW	778,572	778,572		
	4716-Charges-CN	1,427,036	1,427,036		
	4730-Rural Rate Assistance Expense	232,665	232,665		
	4750-Charges-LV	339,515	339,515	0	0.0%
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	314,900	314,900		
	5010-Load Dispatching	16,000	16,000		
	5012-Station Buildings and Fixtures Expense	64,000	64,000		

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var $	Var %
	5016-Distribution Station Equipment - Operation Labour	8,200	8,200		
	5017-Distribution Station Equipment - Operation Supplies and Expenses	17,000	17,000		
	5035-Overhead Distribution Transformers-Operation				
	5065-Meter Expense	11,400	11,400		
	5070-Customer Premises - Operation Labour	22,100	22,100		
	5075-Customer Premises - Materials and Expenses	2,100	2,100		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	77,200	77,200		
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,400	13,400		
	5114-Maintenance of Distribution Station Equipment	1,600	1,600		
	5120-Maintenance of Poles, Towers and Fixtures	6,600	6,600		
	5125-Maintenance of Overhead Conductors and Devices	95,900	95,900		
	5135-Overhead Distribution Lines and Feeders - Right of Way	29,300	29,300		
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices	33,800	33,800		
	5160-Maintenance of Line Transformers	9,900	9,900		
	5165-Maintenance of Street Lighting and Signal Systems				
	5175-Maintenance of Meters	86,200	86,200		
3650-Billing and Collecting	5310-Meter Reading Expense	96,000	96,000		
	5315-Customer Billing	190,300	190,300		
	5320-Collecting	68,700	68,700		
	5325-Collecting- Cash Over and Short	200	200		
	5330-Collection Charges	600	600		
	5335-Bad Debt Expense	80,000	80,000		
	5340-Miscellaneous Customer Accounts Expenses				

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ new dist. rates	2009 @ existing rates	Var $	Var %
3700-Community Relations	5405-Supervision				
	5410-Community Relations - Sundry	5,600	5,600		
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,600	27,600		
	5610-Management Salaries and Expenses	285,900	285,900		
	5615-General Administrative Salaries and Expenses	70,400	70,400		
	5620-Office Supplies and Expenses	107,800	107,800		
	5630-Outside Services Employed	75,400	75,400		
	5635-Property Insurance	21,600	21,600		
	5640-Injuries and Damages	21,700	21,700		
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	73,700	73,700		
	5665-Miscellaneous General Expenses	28,500	28,500		
	5675-Maintenance of General Plant	90,600	90,600		
	5680-Electrical Safety Authority Fees	4,700	4,700		
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	735,424	735,424		
3900-Interest Expense	6005-Interest on Long Term Debt	144,789	144,789		
	6035-Other Interest Expense	18,773	18,773		
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	34,200	34,200		
4000-Income Taxes	6110-Income Taxes	204,993		**204,993**	
4100-Extraordinary & Other Items	6215-Penalties				
Net Income		**644,773**	**-47,556**	**692,329**	**1455.8%**

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var $	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	-2,890,308	-2,881,529	-8,780	(0.3%)
	4025-Street Lighting Energy Sales	-69,413	-67,980	-1,432	(2.1%)
	4030-Sentinel Lighting Energy Sales	-926	-926		
	4035-General Energy Sales	-9,728,401	-9,972,626	**244,225**	**2.4%**
	4062-Billed WMS	-1,443,364	-1,470,146	**26,783**	**1.8%**
	4066-Billed NW	-778,572	-792,131	13,560	1.7%
	4068-Billed CN	-1,427,036	-1,451,413	24,377	1.7%
	4075-Billed-LV	-339,515	-268,609	**-70,906**	**(26.4%)**
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-2,701,224	-2,708,723	7,499	0.3%
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-82,481	-82,481		
	4220-Other Electric Revenues				
	4225-Late Payment Charges	-10,000	-10,000		
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-91,625	-91,625		
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-82,000	-82,000		
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	60,800	60,800		
	4355-Gain on Disposition of Utility and Other Property				
	4375-Revenues from Non-Utility Operations	-49,000	-73,895	24,895	33.7%
	4380-Expenses of Non-Utility Operations	21,000	21,000		
3200-Investment Income	4405-Interest and Dividend Income	-10,000	-30,000	20,000	66.7%
3350-Power Supply Expenses	4705-Power Purchased	12,689,048	12,923,061	**-234,013**	**(1.8%)**
	4708-Charges-WMS	1,210,698	1,233,026	-22,328	(1.8%)
	4710-Cost of Power Adjustments				
	4712-Charges-One-Time				
	4714-Charges-NW	778,572	792,131	-13,560	(1.7%)
	4716-Charges-CN	1,427,036	1,451,413	-24,377	(1.7%)
	4730-Rural Rate Assistance Expense	232,665	237,120	-4,455	(1.9%)
	4750-Charges-LV	339,515	268,609	**70,906**	**26.4%**
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	314,900	253,600	**61,300**	**24.2%**
	5010-Load Dispatching	16,000	15,700	300	1.9%
	5012-Station Buildings and Fixtures Expense	64,000	62,800	1,200	1.9%

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var $	Var %
	5016-Distribution Station Equipment - Operation Labour	8,200	8,400	-200	(2.4%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	17,000	16,400	600	3.7%
	5035-Overhead Distribution Transformers-Operation				
	5065-Meter Expense	11,400	11,600	-200	(1.7%)
	5070-Customer Premises - Operation Labour	22,100	22,300	-200	(0.9%)
	5075-Customer Premises - Materials and Expenses	2,100	2,100		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	77,200	64,500	12,700	19.7%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,400	13,000	400	3.1%
	5114-Maintenance of Distribution Station Equipment	1,600	1,700	-100	(5.9%)
	5120-Maintenance of Poles, Towers and Fixtures	6,600	6,400	200	3.1%
	5125-Maintenance of Overhead Conductors and Devices	95,900	97,100	-1,200	(1.2%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	29,300	29,300		
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices	33,800	34,100	-300	(0.9%)
	5160-Maintenance of Line Transformers	9,900	10,100	-200	(2.0%)
	5165-Maintenance of Street Lighting and Signal Systems				
	5175-Maintenance of Meters	86,200	82,000	4,200	5.1%
3650-Billing and Collecting	5310-Meter Reading Expense	96,000	96,000		
	5315-Customer Billing	190,300	176,900	13,400	7.6%
	5320-Collecting	68,700	66,700	2,000	3.0%
	5325-Collecting- Cash Over and Short	200	200		
	5330-Collection Charges	600	600		
	5335-Bad Debt Expense	80,000	80,000		
	5340-Miscellaneous Customer Accounts Expenses				

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2009 @ existing rates	2008 Projection	Var $	Var %
3700-Community Relations	5405-Supervision				
	5410-Community Relations - Sundry	5,600	5,700	-100	(1.8%)
	5415-Energy Conservation				
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,600	27,600		
	5610-Management Salaries and Expenses	285,900	284,000	1,900	0.7%
	5615-General Administrative Salaries and Expenses	70,400	66,400	4,000	6.0%
	5620-Office Supplies and Expenses	107,800	105,800	2,000	1.9%
	5630-Outside Services Employed	75,400	73,200	2,200	3.0%
	5635-Property Insurance	21,600	21,000	600	2.9%
	5640-Injuries and Damages	21,700	21,100	600	2.8%
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	73,700	23,700	**50,000**	**211.0%**
	5665-Miscellaneous General Expenses	28,500	28,500		
	5675-Maintenance of General Plant	90,600	88,700	1,900	2.1%
	5680-Electrical Safety Authority Fees	4,700	4,600	100	2.2%
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	735,424	622,181	**113,243**	**18.2%**
3900-Interest Expense	6005-Interest on Long Term Debt	144,789	44,789	**100,000**	**223.3%**
	6035-Other Interest Expense	18,773	16,648	2,124	12.8%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	34,200	32,900	1,300	4.0%
4000-Income Taxes	6110-Income Taxes		13,836	-13,836	(100.0%)
4100-Extraordinary & Other Items	6215-Penalties				
Net Income		**-47,556**	**364,769**	**-412,325**	**(113.0%)**

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2008 Projection	2007 Actual	Var $	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	-2,881,529	-2,595,522	**-286,007**	**(11.0%)**
	4025-Street Lighting Energy Sales	-67,980	-65,488	-2,493	(3.8%)
	4030-Sentinel Lighting Energy Sales	-926	-870	-55	(6.4%)
	4035-General Energy Sales	-9,972,626	-10,053,654	**81,028**	**0.8%**
	4062-Billed WMS	-1,470,146	-1,462,262	-7,884	(0.5%)
	4066-Billed NW	-792,131	-862,495	**70,363**	**8.2%**
	4068-Billed CN	-1,451,413	-1,494,621	**43,208**	**2.9%**
	4075-Billed-LV	-268,609	-288,217	19,607	6.8%
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-2,708,723	-2,671,332	**-37,391**	**(1.4%)**
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-82,481	-81,661	-819	(1.0%)
	4220-Other Electric Revenues		-2,110	2,110	100.0%
	4225-Late Payment Charges	-10,000	-8,121	-1,879	(23.1%)
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-91,625	-93,477	1,852	2.0%
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-82,000	-78,471	-3,529	(4.5%)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	60,800	47,624	13,176	27.7%
	4355-Gain on Disposition of Utility and Other Property		-36,734	**36,734**	**100.0%**
	4375-Revenues from Non-Utility Operations	-73,895	-249,029	**175,133**	**70.3%**
	4380-Expenses of Non-Utility Operations	21,000	84,452	**-63,452**	**(75.1%)**
3200-Investment Income	4405-Interest and Dividend Income	-30,000	-74,750	**44,750**	**59.9%**
3350-Power Supply Expenses	4705-Power Purchased	12,923,061	13,148,939	**-225,879**	**(1.7%)**
	4708-Charges-WMS	1,233,026	1,013,542	**219,484**	**21.7%**
	4710-Cost of Power Adjustments				
	4712-Charges-One-Time				
	4714-Charges-NW	792,131	1,139,854	**-347,723**	**(30.5%)**
	4716-Charges-CN	1,451,413	945,355	**506,058**	**53.5%**
	4730-Rural Rate Assistance Expense	237,120	229,731	7,389	3.2%
	4750-Charges-LV	268,609	345,707	**-77,097**	**(22.3%)**
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	253,600	225,621	**27,979**	**12.4%**
	5010-Load Dispatching	15,700	15,066	634	4.2%
	5012-Station Buildings and Fixtures Expense	62,800	42,678	20,122	47.1%

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2008 Projection	2007 Actual	Var $	Var %
	5016-Distribution Station Equipment - Operation Labour	8,400	9,352	-952	(10.2%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	16,400	18,890	-2,490	(13.2%)
	5035-Overhead Distribution Transformers-Operation				
	5065-Meter Expense	11,600	13,118	-1,518	(11.6%)
	5070-Customer Premises - Operation Labour	22,300	27,119	-4,819	(17.8%)
	5075-Customer Premises - Materials and Expenses	2,100	1,143	957	83.7%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	64,500	3,196	**61,304**	**1918.0%**
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,000	12,405	595	4.8%
	5114-Maintenance of Distribution Station Equipment	1,700	1,869	-169	(9.0%)
	5120-Maintenance of Poles, Towers and Fixtures	6,400	6,436	-36	(0.6%)
	5125-Maintenance of Overhead Conductors and Devices	97,100	119,533	-22,433	(18.8%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	29,300	30,185	-885	(2.9%)
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices	34,100	34,601	-501	(1.4%)
	5160-Maintenance of Line Transformers	10,100	14,012	-3,912	(27.9%)
	5165-Maintenance of Street Lighting and Signal Systems				
	5175-Maintenance of Meters	82,000	61,344	20,656	33.7%
3650-Billing and Collecting	5310-Meter Reading Expense	96,000	106,036	-10,036	(9.5%)
	5315-Customer Billing	176,900	155,253	21,647	13.9%
	5320-Collecting	66,700	59,968	6,732	11.2%
	5325-Collecting- Cash Over and Short	200	-249	449	180.5%
	5330-Collection Charges	600	469	131	27.9%
	5335-Bad Debt Expense	80,000	130,344	**-50,344**	**(38.6%)**
	5340-Miscellaneous Customer Accounts Expenses				

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2008 Projection	2007 Actual	Var $	Var %
3700-Community Relations	5405-Supervision				
	5410-Community Relations - Sundry	5,700	6,675	-975	(14.6%)
	5415-Energy Conservation		8,398	-8,398	(100.0%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,600	27,557	43	0.2%
	5610-Management Salaries and Expenses	284,000	259,839	**24,161**	**9.3%**
	5615-General Administrative Salaries and Expenses	66,400	63,265	3,135	5.0%
	5620-Office Supplies and Expenses	105,800	89,407	16,393	18.3%
	5630-Outside Services Employed	73,200	44,968	**28,232**	**62.8%**
	5635-Property Insurance	21,000	19,432	1,568	8.1%
	5640-Injuries and Damages	21,100	21,969	-869	(4.0%)
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	23,700	21,059	2,641	12.5%
	5665-Miscellaneous General Expenses	28,500	28,092	408	1.5%
	5675-Maintenance of General Plant	88,700	70,957	17,743	25.0%
	5680-Electrical Safety Authority Fees	4,600	3,685	915	24.8%
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	622,181	523,913	**98,268**	**18.8%**
3900-Interest Expense	6005-Interest on Long Term Debt	44,789	44,789	0	0.0%
	6035-Other Interest Expense	16,648	-22,059	**38,708**	**175.5%**
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	32,900	31,306	1,594	5.1%
4000-Income Taxes	6110-Income Taxes	13,836	587,000	**-573,164**	**(97.6%)**
4100-Extraordinary & Other Items	6215-Penalties				
Net Income		364,769	244,968	**119,801**	**48.9%**

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	-2,595,522	-2,777,023	**181,501**	6.5%
	4025-Street Lighting Energy Sales	-65,488	-73,295	7,807	10.7%
	4030-Sentinel Lighting Energy Sales	-870	-1,382	512	37.0%
	4035-General Energy Sales	-10,053,654	-9,236,917	**-816,737**	(8.8%)
	4062-Billed WMS	-1,462,262	-1,496,212	**33,950**	2.3%
	4066-Billed NW	-862,495	-1,049,623	**187,129**	17.8%
	4068-Billed CN	-1,494,621	-1,367,502	**-127,119**	(9.3%)
	4075-Billed-LV	-288,217		**-288,217**	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-2,671,332	-2,649,570	-21,762	(0.8%)
	4090-Electric Services Incidental to Energy Sales				
3100-Other Operating Revenues	4210-Rent from Electric Property	-81,661	-88,519	6,857	7.7%
	4220-Other Electric Revenues	-2,110	-1,315	-795	(60.5%)
	4225-Late Payment Charges	-8,121	-13,730	5,609	40.8%
	4230-Sales of Water and Water Power				
	4235-Miscellaneous Service Revenues	-93,477	-81,660	-11,818	(14.5%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-78,471	-57,136	-21,335	(37.3%)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	47,624	37,329	10,295	27.6%
	4355-Gain on Disposition of Utility and Other Property	-36,734	-1,040	**-35,694**	(3432.1%)
	4375-Revenues from Non-Utility Operations	-249,029	-173,150	**-75,878**	(43.8%)
	4380-Expenses of Non-Utility Operations	84,452	17,015	**67,437**	396.3%
3200-Investment Income	4405-Interest and Dividend Income	-74,750	-62,682	-12,068	(19.3%)
3350-Power Supply Expenses	4705-Power Purchased	13,148,939	12,088,617	**1,060,322**	8.8%
	4708-Charges-WMS	1,013,542	1,254,889	**-241,347**	(19.2%)
	4710-Cost of Power Adjustments				
	4712-Charges-One-Time				
	4714-Charges-NW	1,139,854	1,049,623	**90,231**	8.6%
	4716-Charges-CN	945,355	1,367,502	**-422,146**	(30.9%)
	4730-Rural Rate Assistance Expense	229,731	241,323	-11,592	(4.8%)
	4750-Charges-LV	345,707		**345,707**	
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	225,621	228,503	-2,883	(1.3%)
	5010-Load Dispatching	15,066	11,617	3,449	29.7%
	5012-Station Buildings and Fixtures Expense	42,678	41,607	1,071	2.6%

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
	5016-Distribution Station Equipment - Operation Labour	9,352	6,674	2,678	40.1%
	5017-Distribution Station Equipment - Operation Supplies and Expenses	18,890	13,559	5,331	39.3%
	5035-Overhead Distribution Transformers-Operation		11,169	-11,169	(100.0%)
	5065-Meter Expense	13,118	15,115	-1,996	(13.2%)
	5070-Customer Premises - Operation Labour	27,119	42,588	-15,469	(36.3%)
	5075-Customer Premises - Materials and Expenses	1,143	3,677	-2,534	(68.9%)
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	3,196	2,982	215	7.2%
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	12,405	16,289	-3,883	(23.8%)
	5114-Maintenance of Distribution Station Equipment	1,869	1,422	446	31.4%
	5120-Maintenance of Poles, Towers and Fixtures	6,436	18,371	-11,935	(65.0%)
	5125-Maintenance of Overhead Conductors and Devices	119,533	131,374	-11,840	(9.0%)
	5135-Overhead Distribution Lines and Feeders - Right of Way	30,185	45,639	-15,454	(33.9%)
	5145-Maintenance of Underground Conduit				
	5150-Maintenance of Underground Conductors and Devices	34,601	50,178	-15,577	(31.0%)
	5160-Maintenance of Line Transformers	14,012	10,409	3,603	34.6%
	5165-Maintenance of Street Lighting and Signal Systems		304	-304	(100.0%)
	5175-Maintenance of Meters	61,344	59,075	2,270	3.8%
3650-Billing and Collecting	5310-Meter Reading Expense	106,036	105,011	1,025	1.0%
	5315-Customer Billing	155,253	133,676	21,576	16.1%
	5320-Collecting	59,968	57,714	2,254	3.9%
	5325-Collecting- Cash Over and Short	-249	-24	-224	(919.3%)
	5330-Collection Charges	469		469	
	5335-Bad Debt Expense	130,344	82,937	**47,407**	57.2%
	5340-Miscellaneous Customer Accounts Expenses				

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3700-Community Relations	5405-Supervision				
	5410-Community Relations - Sundry	6,675	9,313	-2,638	(28.3%)
	5415-Energy Conservation	8,398	14,461	-6,063	(41.9%)
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,557	27,591	-33	(0.1%)
	5610-Management Salaries and Expenses	259,839	302,186	**-42,347**	(14.0%)
	5615-General Administrative Salaries and Expenses	63,265	69,969	-6,704	(9.6%)
	5620-Office Supplies and Expenses	89,407	85,976	3,432	4.0%
	5630-Outside Services Employed	44,968	27,073	17,895	66.1%
	5635-Property Insurance	19,432	18,948	484	2.6%
	5640-Injuries and Damages	21,969	22,787	-818	(3.6%)
	5645-Employee Pensions and Benefits				
	5655-Regulatory Expenses	21,059	16,128	4,931	30.6%
	5665-Miscellaneous General Expenses	28,092	21,858	6,235	28.5%
	5675-Maintenance of General Plant	70,957	58,192	12,765	21.9%
	5680-Electrical Safety Authority Fees	3,685	4,343	-658	(15.1%)
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	523,913	497,831	**26,082**	5.2%
3900-Interest Expense	6005-Interest on Long Term Debt	44,789	50,158	-5,370	(10.7%)
	6035-Other Interest Expense	-22,059	-51,430	**29,371**	57.1%
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	31,306	34,495	-3,189	(9.2%)
4000-Income Taxes	6110-Income Taxes	587,000	496,000	**91,000**	18.3%
4100-Extraordinary & Other Items	6215-Penalties				
Net Income		244,968	278,716	**-33,749**	(12.1%)

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3000-Sales of Electricity	4006-Residential Energy Sales	-2,777,023	-3,006,242	**229,218**	7.6%
	4025-Street Lighting Energy Sales	-73,295	-67,159	-6,136	(9.1%)
	4030-Sentinel Lighting Energy Sales	-1,382	-1,470	88	6.0%
	4035-General Energy Sales	-9,236,917	-8,344,214	**-892,703**	(10.7%)
	4062-Billed WMS	-1,496,212	-1,641,004	**144,792**	8.8%
	4066-Billed NW	-1,049,623	-1,351,895	**302,272**	22.4%
	4068-Billed CN	-1,367,502	-1,149,068	**-218,434**	(19.0%)
	4075-Billed-LV				
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-2,649,570	-2,757,216	**107,646**	3.9%
	4090-Electric Services Incidental to Energy Sales		-16,205	16,205	100.0%
3100-Other Operating Revenues	4210-Rent from Electric Property	-88,519	-56,499	**-32,020**	(56.7%)
	4220-Other Electric Revenues	-1,315	-354	-961	(271.8%)
	4225-Late Payment Charges	-13,730	-24,085	10,355	43.0%
	4230-Sales of Water and Water Power		-16,605	16,605	100.0%
	4235-Miscellaneous Service Revenues	-81,660	-18,399	**-63,260**	(343.8%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-57,136	-175,024	**117,888**	67.4%
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	37,329	139,514	**-102,185**	(73.2%)
	4355-Gain on Disposition of Utility and Other Property	-1,040		-1,040	
	4375-Revenues from Non-Utility Operations	-173,150	-147,916	**-25,235**	(17.1%)
	4380-Expenses of Non-Utility Operations	17,015	56,573	**-39,557**	(69.9%)
3200-Investment Income	4405-Interest and Dividend Income	-62,682	-33,250	**-29,433**	(88.5%)
3350-Power Supply Expenses	4705-Power Purchased	12,088,617	12,038,835	**49,782**	0.4%
	4708-Charges-WMS	1,254,889	1,460,870	**-205,981**	(14.1%)
	4710-Cost of Power Adjustments		-0	0	100.0%
	4712-Charges-One-Time		14,594	-14,594	(100.0%)
	4714-Charges-NW	1,049,623	1,214,477	**-164,854**	(13.6%)
	4716-Charges-CN	1,367,502	1,028,727	**338,775**	32.9%
	4730-Rural Rate Assistance Expense	241,323		**241,323**	
	4750-Charges-LV		284,777	**-284,777**	(100.0%)
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	228,503	138,434	**90,069**	65.1%
	5010-Load Dispatching	11,617	10,133	1,484	14.6%
	5012-Station Buildings and Fixtures Expense	41,607	41,033	573	1.4%

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
	5016-Distribution Station Equipment - Operation Labour	6,674	16,382	-9,707	(59.3%)
	5017-Distribution Station Equipment - Operation Supplies and Expenses	13,559	400	13,159	3289.7%
	5035-Overhead Distribution Transformers-Operation	11,169	6,315	4,855	76.9%
	5065-Meter Expense	15,115	7,378	7,737	104.9%
	5070-Customer Premises - Operation Labour	42,588	52,627	-10,038	(19.1%)
	5075-Customer Premises - Materials and Expenses	3,677	21	3,656	17817.3%
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	2,982	74,414	**-71,433**	(96.0%)
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	16,289	10,398	5,890	56.6%
	5114-Maintenance of Distribution Station Equipment	1,422	2,474	-1,052	(42.5%)
	5120-Maintenance of Poles, Towers and Fixtures	18,371	22,167	-3,796	(17.1%)
	5125-Maintenance of Overhead Conductors and Devices	131,374	45,330	**86,044**	189.8%
	5135-Overhead Distribution Lines and Feeders - Right of Way	45,639	19,252	**26,387**	137.1%
	5145-Maintenance of Underground Conduit		1,027	-1,027	(100.0%)
	5150-Maintenance of Underground Conductors and Devices	50,178	47,837	2,340	4.9%
	5160-Maintenance of Line Transformers	10,409	15,751	-5,342	(33.9%)
	5165-Maintenance of Street Lighting and Signal Systems	304		304	
	5175-Maintenance of Meters	59,075	67,467	-8,393	(12.4%)
3650-Billing and Collecting	5310-Meter Reading Expense	105,011	135,498	**-30,488**	(22.5%)
	5315-Customer Billing	133,676	146,900	-13,224	(9.0%)
	5320-Collecting	57,714	97,294	**-39,580**	(40.7%)
	5325-Collecting- Cash Over and Short	-24	-17	-7	(40.8%)
	5330-Collection Charges				
	5335-Bad Debt Expense	82,937	31,942	**50,995**	159.7%
	5340-Miscellaneous Customer Accounts Expenses		483	-483	(100.0%)

Variance Analysis: Profit & Loss Detail Table

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3700-Community Relations	5405-Supervision		10,676	-10,676	(100.0%)
	5410-Community Relations - Sundry	9,313	4,905	4,408	89.9%
	5415-Energy Conservation	14,461		14,461	
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	27,591	27,511	79	0.3%
	5610-Management Salaries and Expenses	302,186	233,800	**68,386**	29.2%
	5615-General Administrative Salaries and Expenses	69,969	69,717	252	0.4%
	5620-Office Supplies and Expenses	85,976	70,565	15,410	21.8%
	5630-Outside Services Employed	27,073	55,064	**-27,991**	(50.8%)
	5635-Property Insurance	18,948	18,523	425	2.3%
	5640-Injuries and Damages	22,787	24,092	-1,305	(5.4%)
	5645-Employee Pensions and Benefits		25,398	**-25,398**	(100.0%)
	5655-Regulatory Expenses	16,128	22,356	-6,228	(27.9%)
	5665-Miscellaneous General Expenses	21,858	47,134	**-25,277**	(53.6%)
	5675-Maintenance of General Plant	58,192	79,038	-20,846	(26.4%)
	5680-Electrical Safety Authority Fees	4,343	555	3,788	682.5%
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	497,831	435,963	**61,868**	14.2%
3900-Interest Expense	6005-Interest on Long Term Debt	50,158	96,879	**-46,720**	(48.2%)
	6035-Other Interest Expense	-51,430	140,750	**-192,180**	(136.5%)
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	34,495	28,420	6,075	21.4%
4000-Income Taxes	6110-Income Taxes	496,000	16,091	**479,909**	2982.5%
4100-Extraordinary & Other Items	6215-Penalties		13	-13	(100.0%)
Net Income		278,716	169,844	**108,872**	64.1%

Variance Analysis on OM&A Costs Table

The OM&A Expense Summary Analysis shows the total expenses for the 2006 EDR, actual expenses for 2006 and 2007, along with projected expenses for 2008 and 2009 as mentioned in the previous section, in the following Account Groupings:

3500- Distribution Expenses – Operation
3550- Distribution Expenses – Maintenance
3650- Billing & Collecting
3700- Community Relations
3800- Administrative and General Expenses
3950- Taxes Other Than Income Taxes

The Account Grouping variances as shown in this Table compare the 2009 Projected Expenses with the 2008 Projected Expenses, the 2008 Projected Expenses with the 2007 Actual Expenses, the 2007 Actual Expenses with the 2006 Actual Expenses and the 2006 Actual Expenses with the 2006 EDR Board Approved Expenses. Total Distribution Expenses include Amortization and the Materiality Threshold is calculated as 1% of the Total Distribution Expenses. MPUC will use the lowest Materiality Threshold in order to provide as much detail and review of costs in this analysis.

An explanation of the variances per Account Grouping for each of the years is as follows:

2006 Actual VS 2006 Board Approved EDR

Total OM&A Expenses increased in 2006 by $94,487 over 2006 Board Approved EDR balances. The cost drivers for this increase are:

Labour/Burden Increase	$30,186
Subcontracting Decrease	-$12,288
Bad Debts Increase	$ 50,995
Operations/Admin Net Increase	$25,594
TOTAL OM&A Increase	$ 94,487

The Labour/Burden increase reflects the decrease in billing and collecting staffing levels and in engineering while increasing staffing levels in the managerial roles. Subcontracting decreased due to the installation of radio meters and a reduction in the number of check reads. Bad Debts increased during the year due to a bankruptcy. General operating and administration expenses increased over 2004 expense levels. Details of these cost drivers are provided on the pages following.

Amortization Expense increased in 2006 by $61,868 over 2006 Board Approved EDR balances for a total Distribution Expense increase in 2006 over 2006 Board Approved EDR of $156,355.

The following Account Groupings Table provides details of the total variances in each of the Account Groupings. Each of the Account Grouping sections are then analyzed per individual APH USoA Number for the OM&A Expense variances only. In addition, the materiality level is set as 1% of Total Distribution Expenses in each year.

Account Groupings Table

Account Grouping Description	**Actual - 2006**	**EDR – 2006**	**Variance**
3500-Distribution Expenses - Operation	$ 374,509	$ 272,722	$101,787
3550-Distribution Expenses – Maintenance	$ 336,041	$ 306,118	$ 29,923

Account Grouping Description	Actual - 2006	EDR – 2006	Variance
3650-Billing & Collecting	$ 379,313	$ 412,100	-$ 32,786
3700-Community Relations	$ 23,774	$ 15,581	$ 8,193
3800-Administrative & General Expenses	$ 655,050	$ 673,755	-$18,705
3950-Taxes Other than Income Taxes	$ 34,495	$ 28,420	$ 6,075
TOTAL OM&A Expenses	$1,803,182	$1,708,695	$94,487
Amortization	$ 497,831	$ 435,963	$ 61,868
Total Distribution Expenses	$2,301,013	$2,144,658	$156,355
Percent	1%	1%	
Materiality Threshold	$23,010	$21,447	

MPUC will use $21,447 as the Materiality Threshold in order to provide as much detail as possible in this analysis.

Account Grouping: 3500-Distribution Expenses – Operations

As the Account Groupings Table sets out, the total variance between the 2006 Actual Expenses and the 2006 EDR Expense in the Account Grouping 3500-Distribution Expenses – Operations is $101,787 which is made up of the following individual accounts:

Table 39 Distribution Expenses – Operations

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5005-Operation Supervision & Engineering	$228,503	$138,434	$90,069
#5010- Load Dispatching	$11,617	$10,133	$1,484
#5012-Station Buildings & Fixtures Expense	$41,607	$41,033	$574
#5016-Distribution Stn Equip Operation Labour	$6,674	$16,382	-$9,708
#5017-Distribution Stn Equip Supplies & Exp	$13,559	$400	$13,159
#5035-Overhead Distr. Transformers – Oper'n	$11,169	$6,315	$4,854
#5065-Meter Expense	$15,115	$7,378	$7,737
#5070-Customer Premises- Oper'n Labour	$42,588	$52,627	-$10,038
#5075-Customer Premises – Materials & Exp	$3,677	$21	$3,656
Total 3500-Distribution Expenses – Operation	**$374,509**	**$272,722**	**$101,787**

Those variances which exceed the materiality of $21,447 are explained as follows:

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5005-Operation Supervision & Engineering	**$228,503**	**$138,434**	**$90,069**
Cost Drivers:			
On Call Subcontracting – decrease			$3,900
Training – decrease			$1,800
Labour/Burden – increase			-$95,769
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved data was generated in the EDR filing based on data from 2004. MPUC shares after hours on-call with neighbouring LDC, Barrie Hydro. The on-call expense fluctuates from year to year based on the number of callouts required. In 2006 the actual cost was decreased by $3900. Training also decreased by $1800 in 2006 over 2004.

An additional management staff was hired in late 2005 as a result of increased operational functions that required managerial expertise. In 2004, MPUC's labour compliment totaled 16, 3 of which were management. In 2006, MPUC's labour compliment totaled 15, 6 of which were management. The labour/burden increase in 2006 would have taken into account salary increases for management staff from 2004. Included in Account #5005 are labour/burden costs associated with supervision by working foreman A which fluctuates depending on the type of work performed between Maintenance and Operations. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Reconciliation to Account Groupings Table

Account variances that exceeded the materiality of $21,447 have been explained above. Those variances of less than $21,447 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5010- Load Dispatching	**$11,617**	**$10,133**	**$1,484**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 decreased over 2006 EDR. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5010 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5010. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5010 labour/burden decreased over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Materials expenses however, increased due to the increases in software support costs over 2004 levels for Dromey and Survalent.

As a result of the decrease in labour and increase in software support costs, Load Dispatching increased $1,484 in 2006 over 2006 EDR balances.

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5012-Station Buildings & Fixtures Expense	**$41,607**	**$41,033**	**$574**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. The increase from 2004 to 2006 represents increases in property taxes.

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5016-Distribution Stn Equip Oper'n Labour	**$6,674**	**$16,382**	**-$9,708**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 increased over 2006 EDR labour. Labour in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5016 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5016. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5016 labour/burden increased over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004.

Due to inadvertence, the costs associated with MPUC's substation maintenance were allocated to Account #5016 in 2004. In 2006 these costs were allocated to Account #5017. Rondar Engineering Inc. performs maintenance on our six distribution substations. In 2004, these costs totaled $14,140 in Account #5016. In 2006, these costs totaled $13,559 in Account 5017 (below) a difference of $581. Costs will vary depending on the needs as identified during the maintenance inspections.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5017-Distribution Stn Equip Supplies & Exp	**$13,559**	**$400**	**$13,159**

Explanation:

As indicated in Account #5016 section above, due to inadvertence, the costs associated with MPUC's substation maintenance were allocated to Account #5016 in 2004. In 2006 these costs were allocated to Account #5017. Rondar Engineering Inc. performs maintenance on our six distribution substations. In 2004, these costs totaled $14,140 in Account #5016. In 2006, these costs totaled $13,559 in Account #5017 a difference of $581. Costs will vary depending on the needs as identified during the maintenance inspections.

In the fall of 2004 MPUC registered two wholesale metering points with the IESO. Peterborough Utilities was retained as our Meter Service Provider (MSP), and handles our wholesale meter related issues with the IESO. The balance of the variance represents the costs paid to Peterborough Utilities.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5035-Overhead Distr. Transformers – Oper’n	**$11,169**	**$6,315**	**$4,854**

Explanation:

Expenses were incurred from Green Port Environmental, for the removal and assessment of contaminated soil due to PCBs. Expenses will fluctuate depending on the work required for each removal. In 2006 these expenses increased over 2004 levels.

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden increased in 2006 over 2006 EDR labour. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5035 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5035. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5035 labour increased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5065-Meter Expense	**$15,115**	**$7,378**	**$7,737**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden increased in 2006 over 2006 EDR labour allocations. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5065 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5065. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5065 labour/burden increased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to account # 5665 and Account #5645 in 2004.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5070-Customer Premises- Oper'n Labour	**$42,588**	**$52,627**	**-$10,038**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Due to inadvertence, Customer Premises – Materials in the amount of $3,075 were allocated to Account #5070 in 2004. In 2006, Customer Premises – Materials have been allocated to the correct Account #5075 and totaled $3,677 a variance of $602.

Labour/burden decreased in 2006 over 2006 EDR labour allocations. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5070 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5070. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5070 labour/burden decreased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004, this Account was charged with the full cost of burden associated with our metering department. The labour allocation to this account included other departmental labour such as line crew and did not include the full labour cost of the metering department. The labour/burden costs in 2006 are therefore a better representation of actual expenses incurred in this account.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5075-Customer Premises – Materials & Exp	**$3,677**	**$21**	**$3,656**

Explanation:

Due to inadvertence, the costs associated with customer premises materials were allocated to the labour account in the 2006 EDR and should have been allocated to account #5075. Consequently, the balance shown in the 2006 EDR should have been $3,075 (from acct #5070) plus $21 for a total of $3,096. The resulting variance of $581 can be explained by a general increase in expenses. It is expected that there will be fluctuations in material costs depending on the type of work performed at customer premises

Account Grouping: 3550-Distribution Expenses - Maintenance

The Account Groupings Table sets out the total variance between the 2006 Actual Expenses and the 2006 EDR Expenses is an increase of $29,923. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 40 Distribution Expenses - Maintenance

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5105 –Maintenance Supervision & Engineering	$2,982	$74,414	-$71,433
#5110 - Maintenance Bldg/Fix – Dist'n Stations	$16,289	$10,398	$5,890
#5114 - Maintenance Dist Stn Equipment	$1,422	$2,474	-$1,052
#5120 – Maintenance Poles, Towers, Fixtures	$18,371	$22,167	-$3,796
#5125 – Maintenance Overhead Cond/Devices	$131,374	$45,330	$86,044
#5135 – Overhead Dist Lines/Feeders – ROW	$45,639	$19,252	$26,387
#5145 – Maintenance of Underground Conduit	0.00	$1,027	-$1,027
#5150 – Maintenance of U/G Conductors/De	$50,178	$47,837	$2,340
#5160 – Maintenance of Line Transformers	$10,409	$15,751	-$5,342
#5165 – Maintenance of Street Lighting	$304	0.00	$304
#5175 – Maintenance of Meters	$59,075	$67,467	-$8,393
Total 3500-Distribution Expenses - Operation	**$336,041**	**$306,118**	**$29,923**

Those variances that exceed the materiality of $21,447 are explained as follows:

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5105-Maint. Supervision & Engineering	**$2,982**	**$74,414**	**-$71,433**
Cost Drivers:			
Labour/Burden – decrease			$70,702
Training – decrease			$1,489
Other Expenses – increase			-$758
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. In 2004, the expense included labour/burden allocations in a non-management position of $70,702. In 2005, the position was upgraded to a management position and labour/burden was then allocated to account Operation Supervision in Account #5005. Training was also reduced in Account #5105 by $1,489 over 2006 Actual Expenses due to the reduction in labour/burden costs allocated to this account. Other Expenses increased in 2006 due to the allocation of advertisement costs relating to the new management position which were allocated to Account #5105 in the amount of $600 and an increase in other expenses of $158.

Acct # & Name	**2006 Actual**	**EDR - 2006**	**Variance**
#5125-Maint. of Overhead Cond/Devices	**$131,374**	**$45,330**	**$86,044**
Cost Drivers:			
Labour/Burden - increase			-$68,171
Materials Expense – increase			-$2,002
Sub-Contract Labour – increase			-$9,180
Training – increase			-$6,691
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. An increase in labour/burden in 2006 over 2006 EDR labour totaled $68,171. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5125 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5125. It is expected that the actual labour expenses will fluctuate year over year based on the volume and type of work performed in each particular account and in Account #5125 labour/burden increased by $68,171 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004.

2006 Actual Expenses include an increase of $9,160 in Sub-Contract Labour, as MPUC sub-contracted with McNamara Powerlines to fill a vacant lineman position. Material expenses increased by $2,002. It is expected that material expenses will fluctuate depending on the type of work required and as well increases will result due to inflation. Safety training courses increased in 2006 over 2004 EDR by $6,691.

Acct # & Name	Actual - 2006	EDR – 2006	Variance
#5135-Overhead Distribution Lines & Feeders	**$45,639**	**$19,252**	**$26,387**
Cost Drivers:			
Labour/Burden – increase			-$20,346
Materials & Other Expenses – increase			-$6,041
Total Unexplained Variance			0.00

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. An increase in labour/burden in 2006 over 2006 EDR labour totaled $20,346. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5135 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5135. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5135 labour/burden increased by $20,346 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004.

Materials and Other Expenses increased in 2006 over the 2006 EDR by $6,041 due to an increase in costs relating to the tree trimming.

Reconciliation to Account Groupings Table

Account variances that exceeded the materiality of $21,447 have been explained above. Those variances of less than $21,447 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5110 - Maintenance Bldg/Fix – Dist'n Station	**$16,289**	**$10,398**	**$5,890**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden increased in 2006 over 2006 EDR labour allocations. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5110 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5110. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5110 labour/burden increased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to account # 5665 and Account #5645 in 2004.

Maintenance costs increased in 2006 over the 2006 EDR as a result of increases in snowplowing and grass cutting costs.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5114 - Maintenance Dist Stn Equipment	**$1,422**	**$2,474**	**-$1,052**

Explanation:

The labour/burden allocation in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5114 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden allocated to account #5114. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5114 the labour/burden allocation decreased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004, this Account was charged with a portion of the cost relating to burden associated with one staff member. The burden allocation in 2006 is therefore a better representation of actual expenses incurred in this account.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5120 – Maintenance Poles, Towers, Fixtures	**$18,371**	**$22,167**	**-$3,796**

Explanation:

Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5120 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5120. It is expected that the actual labour expenses will fluctuate year over year based on the volume and type of work performed in each particular account and in Account #5120 labour/burden decreased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

An increase in Material Expense is as a result of scrap inventory being written off in 2006. An increase in Other Expense is as a result of an increase in mobile phone expenses in 2006 over 2006 EDR balances.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5145 – Maint. of Underground Conduit	**0.00**	**$1,027**	**-$1,027**

Explanation:

The labour/burden included in the 2006 EDR should have been allocated to Account #5150 Maintenance of Underground Conductors. MPUC has no underground conduit and the allocation to Account #5145 was in error.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5150 – Maintenance of U/G Conductors/De	**$50,178**	**$47,837**	**$2,340**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5150 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5150. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5150 labour/burden increased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts #5665 and Account #5645 in 2004.

Materials and Other Expenses decreased in 2006 over the 2006 EDR balance due to a reduction in inventory requirements in 2006 vs. the 2004 year.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5160 – Maintenance of Line Transformers	**$10,409**	**$15,751**	**-$5,342**

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5160 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5160. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5160 labour/burden decreased in 2006 over the 2006 EDR balance. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004. Materials & Other Expenses decreased in 2006 over the 2006 EDR due to general decreases in inventory requirements and as a result of a decrease in the purchase of locksmith charges.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5165 – Maintenance of Street Lighting	$304	0.00	$304

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5165 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5165. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5165 labour/burden increased in 2006 over the 2006 EDR balance.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5175 – Maintenance of Meters	$59,075	$67,467	-$8,393

Explanation:

The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5175 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden and vehicle was allocated to account #5175. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5175 labour/burden decreased in 2006 over the 2006 EDR balance.

Materials & Other Expenses decreased in 2006 over the 2006 EDR due to general decreases in metering services required from Oakville Hydro Energy Service for reverification of meters.

Account Grouping: 3650-Billing and Collecting

As the Account Groupings Table sets out, the total variance between the 2006 Actual Expenses and the 2006 EDR Expenses is a decrease of $32,786. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 41 Billing and Collecting

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5310 – Meter Reading Expense	$105,011	$135,498	-$30,488
#5315 – Customer Billing	$133,676	$146,900	-$13,224
#5320 – Collecting	$57,714	$97,294	-$39,580
#5325 – Cash Over and Short	-$24	-$17	-$7
#5335 – Bad Debt Expense	$82,937	$31,942	$50,995
#5340 – Miscellaneous Customer Acct Exp	0.00	$483	-$483
Total 3550-Billing & Collecting	**$379,313**	**$412,100**	**-$32,786**

Those variances that exceed the materiality of $21,447 are explained as follows:

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5310 – Meter Reading Expense	**$105,011**	**$135,498**	**-$30,488**
Cost Drivers:			
Labour/Burden – decrease			$12,920
Meter Reading contract – decrease			$17,568
Total Unexplained Variance			0.00

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. A decrease in MPUC labour/burden in 2006 over 2006 EDR labour totaled $12,920. MPUC contracts out the bulk of meter reading to Olameter Inc. a meter reading company. A decrease in meter reading services in 2006 over the 2006 EDR meter reading services totaled $17,568. In late 2004, MPUC installed radio meters in hard to access areas in the Town of Midland. This resulted in reduced number of visits to customer premises to obtain readings by both MPUC and Olameter. In addition, better processes were instituted in 2005/2006 in the CIS billing system which reduced the number of check reads.

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5320 – Collecting	**$57,714**	**$97,294**	**-$39,580**
Cost Drivers:			
Labour/Burden – decrease			$41,433
Training - decrease			$2,358
Other Expenses – increase			-$4,211
Total Unexplained Variance			0.00

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. A decrease in MPUC labour/burden in 2006 over 2006 EDR labour totaled $41,433. MPUC reorganized the Collections Department in 2006. Process and system integration provided by the setup of electronic downloads directly to our CIS system vs. manual data input along with upgrades to our software, allowed for the transfer of collection duties to hourly workers. An hourly position was deemed redundant as the duties now became supervisory due to the addition of financial responsibility to the job requirements. Consequently, the position was upgraded to management in 2006. In 2006, a change in staff in hourly workers resulted in a 30 year employee taking over the duties of a one year employee. The pay grade for the 30 year

employee is higher than a one year employee which would then result in additional wages in the Collection Department in 2006 vs. the 2006 EDR. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.
In 2004 training increased by $2,358 due to the setup of a new collections module in the CIS Software.

Other Expenses increased in 2006 over the 2006 EDR by $4,211. This increase is attributed to costs associated with the delivery of disconnection notices which was not incurred in 2004. MPUC contracts out the delivery of disconnection notices to Olameter Inc.

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5335 – Bad Debt Expense	**$82,937**	**$31,942**	**$50,995**
Cost Drivers:			
Residential – decrease			$2,283
Commercial - increase			-$53,278
Total Unexplained Variance			0.00

Explanation:
The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. A decrease in MPUC residential bad debts in 2006 over 2006 EDR bad debts totaled $2,283. An increase in commercial bad debts in 2006 over 2006 EDR bad debts totaled $53,278. MPUC suffered bad debt losses due to the assignment in bankruptcy of one of our commercial customers in 2006.

Reconciliation to Account Groupings Table
Account variances that exceeded the materiality threshold of $21,447 have been explained above. Those variances of less than $21,447 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	**Actual - 2006**	**EDR - 2006**	**Variance**
#5315 – Customer Billing	**$133,676**	**$146,900**	**-$13,224**

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 Data. Labour/burden decreased in 2006 over 2006 EDR labour. In 2004 our senior billing staff was on sick leave for 4 months of the year. During this time, MPUC hired temporary staff to cover in billing.

Office supplies decreased in 2006 over the 2006 EDR expenses due to decreased lease costs on our mailing machine. Office supplies expenses decreased, however, postage increased due to the increase in postage rates, and the mailing of additional past due notices. IT expenses increased in 2006 as the result an increase in our IT support contract and various programming changes.

Acct # & Name	2006 Actual	EDR - 2006	Variance
#5325 – Cash Over & Short	**-$24**	**-$17**	**-$7**

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5340 – Miscellaneous Customer Acct Exp	**0.00**	**$483**	**-$483**

Explanation:
Miscellaneous printing costs were allocated to account #5340 in 2004. In 2006 these miscellaneous expenses have been allocated to customer billing account # 5315.

Account Grouping: 3700-Community Relations

As the Account Groupings Table sets out, the total variance between the 2006 Actual Expenses and the 2006 EDR Expenses is an increase of $8,193. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 42 Community Relations

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5405 – Supervision	0.00	$10,676	-$10,676
#5410 – Community Relations – Sundry	$9,313	$4,905	$4,408
#5415 – Energy Conservation	$14,461	0.00	$14,461
Total 3700 – Community Relations	**$23,774**	**$15,581**	**$8,193**

No variances exceed the materiality level of $21,447. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5405 – Supervision	**0.00**	**$10,676**	**-$10,676**

Explanation:
The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. In 2006 labour for community relations was booked to account #5410 Community Relations – Sundry listed below.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5410 – Community Relations – Sundry	**$9,313**	**$4,905**	**$4,408**

Explanation:
The 2006 Board Approved EDR data was generated in the EDR filing based on 2004 data. Due to inadvertence MPUC's a portion of MPUC's Community Relations labour in 2004 was allocated to account #5405 as noted above. The decrease of labour/burden in account #5405 – Supervision coupled with the increase in #5410 – Community Relations – Sundry nets to a decrease over the 2006 EDR expenses. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5160 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5410. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5410 labour/burden decreased in 2006 over the 2006 EDR balance. In 2004 only direct labour costs were included in this account. Burden was inadvertently allocated to accounts # 5665 and Account #5645 in 2004.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5415 – Energy Conservation	**$14,461**	**0.00**	**$14,461**

Explanation:

In 2006 all expenses associated with Third Tranche CDM funds were posted to account #5415 – Energy Conservation. MPUC did not undertake any Third Tranche activities and expenses in 2004.

Account Grouping: 3800-Administrative and General Expenses

AS the Account Groupings Table sets out, the total variance between the 2006 Actual Expenses and the 2006 EDR Expenses is a decrease of $18,705. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 43 Administrative and General Expenses

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5605 – Executive Salaries & Expenses	$27,591	$27,511	$79
#5610 – Management Salaries & Expenses	$302,186	$233,800	$68,386
#5615 – General Admin. Salaries & Expenses	$69,969	$69,717	$252
#5620 – Office Supplies & Expenses	$85,976	$70,565	$15,411
#5630 – Outside Services Employed	$27,073	$55,064	-$27,991
#5635 – Property Insurance	$18,948	$18,523	$425
#5640 – Injuries & Damages	$22,787	$24,092	-$1,305
#5645 – Employee Pensions & Benefits	0.00	$25,398	-$25,398
#5655 – Regulatory Expenses	$16,128	$22,356	-$6,228
#5665 – Miscellaneous General Expenses	$21,858	$47,134	-$25,277
#5675 – Maintenance of General Plant	$58,192	$79,038	-$20,846
#5680 – Electrical Safety Authority Fees	$4,343	$555	$3,788
Total 3800-Administrative&General Expenses	**$655,050**	**$673,755**	**-$18,705**

Those variances which exceed the materiality of $21,447 are explained as follows:

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5610 – Management Salaries & Expenses	**$302,186**	**$233,800**	**$68,386**
Cost Drivers:			
Labour/Burden – increase			-$77,336
Training – decrease			$8,315
Other Expense – decrease			$635
Total Unexplained Variance			0.00

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. In 2004, MPUC's labour compliment totaled 16, 3 of which were management. In 2006, MPUC's labour compliment totaled 15, 6 of which were management. Operations Management staff increased by one position, and the Administrative/Finance compliment increased by two over 2004 levels, both positions resulting in decreases in the unionized staffing levels. The labour increase in 2006 would have taken into account salary increases for management staff from 2004 and as well increases in wages paid to managers who have moved to the next level on the salary scale and incentives paid.

Training Expenses in 2004 included management training courses for new managers. Other Expenses decreased as telephone costs which were posted to Account #5610 in 2004 were posted to Account #5620 in 2006.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5630 – Outside Services Employed	**$27,073**	**$55,064**	**-$27,991**
Cost Drivers:			
Legal, Audit Fees - decrease			$9,961
Consulting Fees – decrease			$14,041
Membership Fees – CHEC – decrease			$6,903
Safety Audit Fees – increase			-$2,914
Total Unexplained Variance			0.00

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. A decrease in legal and audit fees in the amount of $9,961 in 2006 over 2006 EDR balances due to less legal representation requirements. Consulting fees reduced in 2006 over the 2006 EDR in the amount of $14,041 as MPUC did not require these services.

CHEC membership fees were allocated to Account #5630 in 2004 vs. Account #5665 – Miscellaneous General Expenses in 2006. Safety Audit fees were required in 2006 in the amount of $2,914.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5645 – Employee Pensions & Benefits	**0.00**	**$25,398**	**-$25,398**
Cost Drivers:			
Burden Allocation - decrease			$25,398
Total Unexplained Variance			0.00

Explanation:

In 2004, burden not directly allocated to expenses or capital and was recorded in Account #5645 and #5665. In 2006, the labour/burden allocation includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5410 and the $3,000 represented 1% of total labour, 1% of the 2006 burden and vehicle was allocated to account #5410.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5665 – Miscellaneous General Expenses	**$21,858**	**$47,134**	**-$25,277**
Cost Drivers:			
Membership Fees – CHEC – increase			-$3,560
Membership Fees – EDA – increase			-$1,550
Membership Fees – USF – increase			-$5,000
Labour/Burden – decrease			$35,387
Total Unexplained Variance			0.00

Explanation:

The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. Increases in membership fees in CHEC, EDA and USF (Utility Standards Forum) in 2006 over 2006 EDR balances totaled $10,110. In 2004, CHEC membership fees were allocated to Account #5630 – Outside Services Employed vs. Account #5665 – Miscellaneous General Expenses in 2006. As indicated in other sections in the variance account analysis, in 2004, burden not directly allocated to expenses and capital was recorded in Account #5645 and #5665. In 2006 labour/burden includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5410 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5410.

Reconciliation to Account Groupings Table

Account variances that exceeded the materiality threshold of $21,447 have been explained above. Those variances less than $21,447 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2006 Actual	EDR - 2006	Variance
#5605 – Executive Salaries & Expenses	$27,591	$27,511	$79

Acct # & Name	2006 Actual	EDR - 2006	Variance
#5615 – General Admin. Salaries & Expenses	$69,969	$69,717	$252

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5620 – Office Supplies & Expenses	$85,976	$70,565	$15,411

Explanation:

MPUC's bank charges decreased slightly in 2006 vs 2004, while office supplies increased as a result of increases in general office supplies including computer printing expenses, telephone charges, courier charges, internet and email annual support fees.

Acct # & Name	2006 Actual	EDR - 2006	Variance
#5635 – Property Insurance	$18,948	$18,523	$425

Acct # & Name	2006 Actual	EDR - 2006	Variance
#5640 – Injuries & Damages	$22,787	$24,092	-$1,305

Explanation:

MPUC's injury and damage insurance decreased in 2006. In 2004 MPUC paid for the repairs as a result of damages to Bell Canada poles and a third party vehicle. MPUC's property and injury/damage insurance premiums decreased in 2006 over 2004 rates.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5655 – Regulatory Expenses	$16,128	$22,356	-$6,228

Explanation:
The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. A decrease in in 2006 over 2006 EDR Regulatory Expenses was as a result of the difference between OEB cost assessments invoiced for the 2005/2006 fiscal year up to April 30, 2006 and OEB cost assessments previously included in MPUC's rates.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5675 – Maintenance of General Plant	**$58,192**	**$79,038**	**-$20,846**

Explanation:
The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. Labour/burden in 2006 includes a percentage of total burden allocated on a pro rata basis based on 2006 labour costs in the various labour accounts. For example, if actual labour expense in 2006 was $3,000 for account #5675 and the $3,000 represented 1% of total labour, then 1% of the 2006 burden was allocated to account #5675. It is expected that the actual labour expenses will fluctuate over the year based on the volume and type of work performed in each particular account and in Account #5675 labour/burden decreased in 2006 over the 2006 EDR balance.

Wireless Expenses decreased in 2006 over the 2006 EDR balances as a result of changes in our internet service provider. Other plant expenses decreased in 2006. In 2004 MPUC expenses included building repairs. In addition, building cleaning costs decreased as a new cleaning company was hired, and heating costs decreased in 2006 over 2004 expenses.

Acct # & Name	Actual - 2006	EDR - 2006	Variance
#5680 – Electrical Safety Authority Fees	**$4,343**	**$555**	**$3,788**

Explanation:
The 2006 EDR Board Approved data was generated in the EDR filing based on 2004 data. Annual ESA association fees increased in 2006 over 2004 levels.

Account Grouping: 3950 – Taxes Other Than Income Taxes

As the Account Groupings Table sets out, the total variance between the 2006 Actual Expenses and the 2006 EDR Expenses is an increase of $6,075. Property Taxes increased in 2006 over 2004 rates. In addition, due to inadvertence MPUC included capital tax payments in account #6105 in 2006.

Acct # & Name	2006 Actual	EDR - 2006	Variance
#6105 – Taxes Other Than Income Taxes	**$34,495**	**$28,420**	**$6,075**

2007 Actual VS 2006 Actual

Total OM&A Expenses decreased $18,182 in 2007 over 2006 Actual balances. The cost drivers for this increase are:

Labour/Burden Decrease	-$103,047
Subcontracting Decrease	-$ 10,156
Bad Debts Increase	$ 47,407
Outside Services Increase	$ 17,895
IT Expenses Increase	$ 20,453
Operations/Admin Net Increase	$ 9,266
TOTAL OM&A Decrease	-$ 18,182

In 2007, although total labour dollars increased, the amount attributed to OM&A decreased as more labour was used in capital projects throughout the year. In addition, one management position was eliminated due to the billing system conversion. Subcontracting decreased as services were not required and again, in 2007 another commercial customer bankruptcy resulted in an increase in bad debt expense. Outside services increased due to legal and audit requirements. IT expenses increased as we moved to the Harris billing system and other increases in operations and administration resulted in an overall decrease in OM&A expenses of $18,182. More detailed explanations for these increases are provided on the pages following.

Amortization Expense increased in 2007 by $26,082 over 2006 Actual balances for a total Distribution Expense increase of $7,900 over 2006 Actual balances.

The following Account Groupings Table provides details of the total variances in each of the Account Groupings. Each of the Account Grouping sections are then analyzed per individual APH USoA Number for the OM&A Expense variances only. In addition, the materiality level is set as 1% of Total Distribution Expenses in each year.

Account Grouping Description	2007 Actual	2006 Actual	Variance
3500-Distribution Expenses - Operation	$ 352,987	$ 374,509	-$ 21,521
3550-Distribution Expenses – Maintenance	$ 283,582	$ 336,041	-$ 52,459
3650-Billing & Collecting	$ 451,821	$ 379,313	$ 72,507
3700-Community Relations	$ 15,073	$ 23,774	-$ 8,701
3800-Administrative & General Expenses	$ 650,232	$ 655,050	-$ 4,819
3950-Taxes Other than Income Taxes	$ 31,306	$ 34,495	-$ 3,189
TOTAL OM&A Expenses	$1,785,000	$1,803,182	-$ 18,182
Amortization	$ 523,913	$ 497,831	$ 26,082
Total Distribution Expenses	$2,308,913	$2,301,013	$7,900
Percent	1%	1%	
Threshold	$23,089	$23,010	

MPUC will use $23,010 as the Materiality Threshold in order to provide as much detail as possible in this analysis.

Account Grouping: 3500-Distribution Expenses – Operations

As the Account Groupings Table sets out, the total variance between 2007 Actual Expenses and 2006 Actual Expenses in the Account Grouping 3500-Distribution Expenses – Operations is a decrease of $21,521. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 44 Distribution Expenses - Operations

Acct # & Name	2007 Actual	2006 Actual	Variance
#5005-Operation Supervision & Engineering	$ 225,621	$ 228,503	-$ 2,883
#5010- Load Dispatching	$ 15,066	$ 11,617	$ 3,449
#5012-Station Buildings & Fixtures Expense	$ 42,678	$41,607	$ 1,071
#5016-Distribution Stn Equip Operation Labour	$ 9,352	$ 6,674	$2,678
#5017-Distribution Stn Equip Supplies & Exp	$ 18,890	$ 13,559	$ 5,331
#5035-Overhead Distr. Transformers – Oper'n	$ 0	$ 11,169	-$ 11,169
#5065-Meter Expense	$ 13,118	$ 15,115	-$ 1,996
#5070-Customer Premises- Oper'n Labour	$ 27,119	$ 42,588	-$15,469
#5075-Customer Premises – Materials & Exp	$ 1,143	$ 3,677	-$ 2,534
Total 3500-Distribution Expenses - Operation	**$ 352,987**	**$ 374,509**	**$ 21,521**

No variances exceed the materiality level of $23,010. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5005-Operation Supervision & Engineering	**$ 225,621**	**$ 228,503**	**-$ 2,883**

Explanation:
MPUC shares after hours oncall with neighbouring LDC, Barrie Hydro. The oncall expense fluctuates from year to year based on the number of callouts required. In 2007 the actual cost decreased. Training expenses increased in 2007 over 2006 as a result of additional courses taken by management.

Labour/burden expenses decreased in 2007 over 2006 expenses as the result of the allocation of labour/burden costs associated with the working foreman A. Included in Account #5005 are labour/burden costs associated with supervision by working foreman A which fluctuates year over year depending on the type of work performed between Maintenance and Operations. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material increases in 2007 over 2006 include drafting supply increases, advertising increases for a new lineman position and general office supplies.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5010- Load Dispatching	**$ 15,066**	**$ 11,617**	**$3,449**

Explanation:
Labour/burden expenses increased in 2007 over 2006 expenses. It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5010 labour/burden increased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material increases in 2007 over 2006 is the result of annual increases in support fees for SCADA and DESS software required for our distribution system.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5012-Station Buildings & Fixtures Expense	**$ 42,678**	**$ 41,607**	**$ 1,071**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5012 labour/burden increased by over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses increased in 2007 over 2006 expenses for supplies required at the Queen St. Substation. Property Tax increases on our substation properties increased in 2007 over 2006 expenses.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5016-Distribution Stn Equip Oper'n Labour	**$9,352**	**$ 6,674**	**$2,678**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5016 labour/burden increased by over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5017-Distribution Stn Equip Supplies & Exp	**$ 18,890**	**$ 13,559**	**$ 5,331**

Explanation:
Substation maintenance expenses increased in 2007 over 2006 expenses. These costs include maintenance work performed by Rondar Engineering Inc. on our six distribution substations. Maintenance is performed on each of MPUC's substations every two years by Rondar Engineering Inc. In 2006 only two of MPUC's substations had maintenance work performed, while in 2007 three of MPUC's substations had maintenance work performed which resulted in the increase. Costs will vary depending on the needs as identified during the maintenance inspections.

In 2007 MPUC registered it's two remaining wholesale metering points with the IESO. In 2007 MPUC had four wholesale metering points registered with the IESO. Peterborough Utilities was retained as our Meter Service Provider (MSP), and handles our wholesale meter related issues with the IESO. The variance represents the costs paid to Peterborough Utilities on the two additional metering points in 2007.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5035-Overhead Distr. Transformers – Oper'n	**$ 0**	**$ 11,169**	**-$ 11,169**

Explanation:
Expenses incurred in 2006 from Green Port Environmental were for the removal and assessment of contaminated soil due to PCBs. Expenses will fluctuate depending on the work required for each removal. This work was completed in 2006, and therefore no expenses or labour/burden associated with this type of removal was incurred in 2007.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5065-Meter Expense	**$ 13,118**	**$ 15,115**	**-$ 1,996**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5065 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5070-Customer Premises- Oper'n Labour	**$ 27,119**	**$ 42,588**	**-$ 15,469**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5070 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5075-Customer Premises – Materials & Exp	**$ 1,143**	**$ 3,677**	**-$ 2,534**

Explanation:

It is expected that there will be fluctuations in material costs depending on the type of work performed at customer premises. Material expenses decreased in 2007 over 2006 expenses as a result of the reduction of inventory requirements for the work being done, which is also explained by the decrease in labour hours outlined in account #5070 above.

Account Grouping: 3550-Distribution Expenses - Maintenance

As the Account Grouping Table sets out, the total variance between the 2007 Actual Expenses and 2006 Actual Expenses in the Account Grouping #3550 – Distribution Expenses – Maintenance is a reduction of -$52,459. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 45 Distribution Expenses - Maintenance

Acct # & Name	2007 Actual	2006 Actual	Variance
#5105 – Maintenance Supervision&Engineering	$3,197	$2,980	$215
#5110 - Maintenance Bldg/Fix – Dist'n Stations	$12,405	$16,289	-$3,883
#5114 - Maintenance Dist Stn Equipment	$1,869	$1,422	$446
#5120 – Maintenance Poles, Towers, Fixtures	$6,436	$18,371	-$11,935
#5125 – Maintenance Overhead Cond/Devices	$119,533	$131,374	-$11,840
#5135 – Overhead Dist Lines/Feeders – ROW	$30,185	$45,639	-$15,454
#5150 – Maintenance of U/G Conductors/De	$34,601	$50,178	-$15,577
#5160 – Maintenance of Line Transformers	$14,012	$10,409	$3,603
#5165 – Maintenance of Street Lighting	$0	$304	-$304
#5175 – Maintenance of Meters	$61,344	$59,075	$2,269
Total 3500-Distribution Expenses - Operation	**$283,582**	**$336,041**	**-$52,459**

No variances exceed the materiality level of $23,010. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5105-Maint. Supervision & Engineering	$3,197	$2,980	$215

Acct # & Name	2007 Actual	2006 Actual	Variance
#5110 - Maintenance Bldg/Fix – Dist'n Station	$ 12,405	$ 16,289	-$ 3,883

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5110 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Maintenance of Substation expenses increased over 2006 expenses as a result of increased snow removal charges.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5114 - Maintenance Dist Stn Equipment	$ 1,869	$ 1,422	$ 446

Acct # & Name	2007 Actual	2006 Actual	Variance
#5120 – Maintenance Poles, Towers, Fixtures	$ 6,436	$ 18,371	-$ 11,935

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5120 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material expenses decreased over 2006 expenses as a result of scrap inventory being written off in 2006. Other expense increases are due to increases in cell phone charges.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5125-Maint. of Overhead Cond/Devices	$ 119,533	$ 131,374	-$ 11,840

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5125 labour/burden increased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

It is expected that there will be fluctuations in material costs depending on the type of work performed with respect to the maintenance of overhead conductors and devices. Material expenses decreased by as a result of lower material requirements in overhead maintenance work in 2007. Subcontracting expenses decreased due to subcontract workers being required in 2006 due to staffing shortages. Training expenses also decreased over 2006 expenses. In 2006 EUSA training courses for staff were provided over and above yearly training requirements.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5135-Overhead Distribution Lines & Feeders	$30,185	$45,639	-$15,454

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5135 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material and other expenses decreases include lower tree trimming costs and lower material expenses. It is expected that there will be fluctuations in material costs depending on the type of work performed on overhead distribution lines and feeders.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5150 – Maintenance of U/G Conductors & Devices	**$ 34,601**	**$ 50,178**	**-$ 15,577**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5150 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses decreased as a result of lower material requirements in the maintenance of underground conductors and devices. It is expected that there will be fluctuations in material costs depending on the type of work performed with respect to the maintenance of underground conductors and devices.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5160 – Maintenance of Line Transformers	**$ 14,012**	**$ 10,409**	**$ 3,603**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5160 labour/burden increased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses increased as a result of the purchase of padmount transformer locks. It is expected that there will be fluctuations in material costs depending on the type of work performed with respect to the maintenance of line transformers.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5165 – Maintenance of Street Lighting	**$ 0**	**$ 304**	**-$ 304**

Acct # & Name	2007 Actual	2006 Actual	Variance
#5175 – Maintenance of Meters	**$ 61,344**	**$ 59,075**	**$ 2,269**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5175 labour/burden increased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material expenses increased as the result of additional phone lines required for MPUC's wholesale metering points. As the points were registered with the IESO, it was a requirement to install hard wired phone lines for meter reading and verification purposes.

Account Grouping: 3650-Billing and Collecting
As the Account Grouping Table sets out, the total variance between the 2007 Actual Expenses and the 2006 Actual Expenses of is an increase of $72,507. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 46 Billing and Collecting

Acct # & Name	2007 Actual	2006 Actual	Variance
#5310 – Meter Reading Expense	$ 106,036	$ 105,011	$ 1,025
#5315 – Customer Billing	$ 155,253	$ 133,676	$ 21,576
#5320 – Collecting	$ 59,968	$ 57,714	$ 2,254
#5325 – Cash Over and Short	-$ 249	-$ 24	-$ 224
#5330 – Collection Charges	$ 469	$ 0	$ 469
#5335 – Bad Debt Expense	$ 130,344	$ 82,937	$ 47,407
Total 3550-Billing & Collecting	**$ 451,821**	**$ 379,313**	**$ 72,507**

Those variances which exceed the materiality of $23,010 are explained as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5335 – Bad Debt Expense	**$ 130,344**	**$ 82,937**	**$ 47,407**
Cost Drivers:			
Residential – decrease			-$ 11,654
Commercial - increase			$ 59,061
Total Unexplained Variance			0.00

Explanation:

A decrease in MPUC residential bad debts in 2007 over 2006 bad debts totaled $11,654. An increase in commercial bad debts in 2007 over 2006 bad debts totaled $59,061. MPUC suffered bad debt losses due to the bankruptcy one of our GS>50 customers again in 2007.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality of $23,010 have been explained above. Those variances of less than $23,010 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5310 – Meter Reading Expense	**$ 106,036**	**$ 105,011**	**$ 1,025**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5310 labour/burden increased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Materials decreased over 2006 expenses. In 2007 no general office supply expenses were allocated to meter reading expenses.

MPUC contracts out the bulk of meter reading work to Olameter Inc. a meter reading company. In 2007 there was a small increase in meter reading service expenses over 2006 expenses.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5315 – Customer Billing	**$ 155,253**	**$ 133,676**	**$ 21,576**

Explanation:
In 2007 there was a slight decrease in MPUC labour allocations over 2006 labour . In November 2007 MPUC had a change in billing staff. The new billing clerk hired commenced employment at a lower pay rate than the previous incumbent. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Office Supply Expenses decreased in 2007 over the 2006, while postage expenses increased in 2007 over 2006. MPUC converted to the Harris billing software in May 2007 from the Advanced Infinity System. As a result of the conversion the IT function was outsourced which resulted in the reduction in labour as MPUC's internal IT position has been eliminated. Until May of 2007, the labour allocation for this position was posted to Account #5610 Management Salaries and Expenses, as the IT position was in Management. Due to these changes, IT expenses therefore increased in 2007 over 2006. Training expenses also increased in 2007 due to the conversion to the new Harris billing software.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5320 – Collecting	**$ 59,968**	**$ 57,714**	**$ 2,254**

Explanation:
In 2007 labour decreased over 2006 levels. In 2006, a change in staff in hourly workers resulted in a 30 year employee taking over the duties of a one year employee. The pay grade for the 30 year employee is higher than a one year employee. During the transition period of approximately 2 months, both employees performed the function, which resulted in additional wages in the Collection Department in 2006. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. In 2007 training decreased due to the setup of the collections module in the CIS Software that took place in 2006.

Other Expenses increased in 2007 over the 2006. This increase is attributed to costs associated with the delivery of disconnection notices for a full year in 2007. In 2006 the delivery of disconnection notice charges commenced in June.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5325 – Collecting – Cash Over and Short	**-$ 249**	**-$ 24**	**-$ 224**

Acct # & Name	2007 Actual	2006 Actual	Variance
#5330 – Collection Charges	**$ 469**	**$ 0**	**$ 469**

Explanation:

In 2007 collection charges in the amount of $469 were paid to outside collection agencies to assist in the collection of final accounts. Due to inadvertence, in previous years these collection charges were posted to Account #5335 Bad Debt Expenses.

Account Grouping: 3700-Community Relations

As the Account Groupings Table sets out, the total variance between the 2007 Actual Expenses and 2006 Actual Expenses is a reduction of $8,701. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 47 Community Relations

Acct # & Name	2007 Actual	2006 Actual	Variance
#5410 – Community Relations – Sundry	$ 6,675	$ 9,313	-$ 2,638
#5415 – Energy Conservation	$ 8,398	$ 14,461	-$ 6,063
Total 3700 – Community Relations	**$ 15,073**	**$ 23,774**	**-$ 8,701**

No variances exceed the materiality level of $23,010. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5410 – Community Relations – Sundry	**$ 6,675**	**$ 9,313**	**-$ 2,638**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5410 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective

Bargaining Agreement. Material expenses also decreased as a result of lower material requirements. It is expected that there will be fluctuations in material costs depending on the type of work performed with respect to community relation expenses.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5415 – Energy Conservation	**$ 8,398**	**$14,461**	**-$ 6,063**

Explanation:

In 2006 and 2007, MPUC expenses relating to the Third Tranche CDM programs were allocated to account #5415 Energy Conservation in accordance with the direction received from the Ontario Energy Board.

Account Grouping: 3800-Administrative and General Expenses

As the Account Groupings Table sets out, the total variance between 2007 Actual Expenses and 2006 Actual Expenses is a reduction of $4,819. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 48 Administrative and General Expenses

Acct # & Name	2007 Actual	2006 Actual	Variance
#5605 – Executive Salaries & Expenses	$27,557	$27,591	-$33
#5610 – Management Salaries & Expenses	$259,839	$302,186	-$42,347
#5615 – General Admin. Salaries & Expenses	$ 63,265	$69,969	-$6,704
#5620 – Office Supplies & Expenses	$89,407	$85,976	$3,432
#5630 – Outside Services Employed	$44,968	$27,073	$17,895
#5635 – Property Insurance	$19,432	$18,948	$484
#5640 – Injuries & Damages	$21,969	$22,787	-$818
#5655 – Regulatory Expenses	$21,059	$16,128	$4,931
#5665 – Miscellaneous General Expenses	$28,092	$21,858	$6,234
#5675 – Maintenance of General Plant	$70,957	$58,192	$12,765
#5680 – Electrical Safety Authority Fees	$3,685	$4,343	-$658
Total 3800-Administrative&General Expenses	**$650,232**	**$655,050**	**-$4,819**

Those variances which exceed the materiality of $23,010 are explained as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5610 – Management Salaries & Expenses	**$259,839**	**$302,186**	**-$42,347**
Cost Drivers:			
Labour/Burden – decrease			$39,612
Training – decrease			$2,735
Total Unexplained Variance			0.00

Explanation:

In 2006, MPUC's Administrative/Finance management labour totaled 4 staff members. In 2007, MPUC's Administrative/Finance management labour decreased by 1 to 3 staff members in June as a result of our billing system conversion. MPUC converted to the Harris billing software in May 2007 from the Advanced Infinity System. As a result of the conversion, the IT management position was outsourced which resulted in a reduction in labour/burden. Due to these changes, IT expenses in Account # 5315 Customer Billing increased. 2007 labour/burden expenses would have also taken into account salary increases for management staff from 2006, along with increases in wages paid to managers who moved to the next level of their salary scale and incentives paid for the year. In 2007, management salaries included one management position at the probationary level for part of the year.

Training Expenses in 2007 decreased over 2006 expenses as MPUC experienced changes in one management staff position in the fall of 2007. Due to this change, courses scheduled for the fall and winter months were postponed to a future date for the new incumbent.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality of $23,010 have been explained above. Those variances of less than $23,010 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2007 Actual	2006 Actual	Variance
#5605 – Executive Salaries & Expenses	**$27,557**	**$27,591**	**-$33**

Acct # & Name	2007 Actual	2006 Actual	Variance
#5615 – General Admin. Salaries & Expenses	**$63,265**	**$69,969**	**-$6,704**

Explanation:
2007 labour/burden expenses increased over 2006 expenses due to a full time staff member being off on sick leave in the winter of 2007 for approx. 6 weeks. Temporary staff were hired during the sick leave. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

In 2006, MPUC required an Actuarial analysis to be done with respect to our retirement benefit liability. After completion of the analysis the retirement benefit liability was increased thereby increasing the retirement benefit expense account. In addition, the annual retirement benefit premiums for 2007 increased over 2006 expenses.

Training expenses in 2007 decreased over 2006 expenses due to training required in 2006 for our General Ledger package. No training expenses were incurred in 2007.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5620 – Office Supplies & Expenses	**$89,407**	**$85,976**	**$3,432**

Explanation:
Office supplies over 2006 expenses as a result of increases in costs associated with various general office supplies including telephone charges, utility charges, bank charges and internet access fees.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5630 – Outside Services Employed	**$44,968**	**$27,073**	**$17,895**

Explanation:
An increase in legal and audit fees in 2007 over 2006 balances is as a result of an increase in audit fees coupled with increased legal fees due to the review of legal agreements with respect

to the property lease agreement with SCBN, MPUC's building lease agreement with Bright Side Management and legal fees associated with billing. In addition, legal reviews of two of MPUC's GS>50 customer bankruptcy protection agreements was required in 2007.

Consulting fees also increased in 2007 over the 2006 as MPUC required services for review of the 2007 cost allocation filing, and general business consulting.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5635 – Property Insurance	$19,432	$18,948	$484

Acct # & Name	2007 Actual	2006 Actual	Variance
#5640 – Injury & Damages	$21,969	$22,787	-$818

Explanation:
Injury & Damage Insurance rates decreased over 2006 expenses due to the claims incurred in 2006. A general increase in insurance rates was implemented in 2007.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5655 – Regulatory Expenses	$21,059	$16,128	$4,931

Explanation:
2007 Regulatory expenses increased over 2006 expenses. In 2006 OEB cost assessment expenses over the 1999/2000 approved balances were reallocated to a variance account, as approved by the OEB. This reallocation ceased as of April 30, 2006. In addition, MPUC paid additional expenses in cost awards over 2006 expenses.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5665 – Miscellaneous General Expenses	$28,092	$21,858	$6,234

Explanation:
Membership fees increased over 2006 expenses which included membership fees for Cornerstone Hydro Electric Concepts (CHEC), Electricity Distributors Association (EDA), and

Utility Standards Forum (USF). Other misc. membership fee increases include OACETT, Chamber of Commerce, AccPac, and Payroll association fees.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5675 – Maintenance of General Plant	**$70,957**	**$58,192**	**$12,765**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5675 labour/burden decreased over the 2006 expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material expenses also decreased as a result of lower material requirements. It is expected that there will be fluctuations in material costs depending on the type of work performed with respect to general plant expenses. Other plant expenses increased due to snowplowing, gas and hydro charges, and repairs to the quanset hut garage door.

Acct # & Name	2007 Actual	2006 Actual	Variance
#5680 – Electrical Safety Authority Fees	**$3,685**	**$4,343**	**-$658**

Explanation:
ESA fees decreased over 2006 expenses. The decrease is due to a reduction in annual fees, coupled with a charge in 2006 for a building inspection. The building inspection charge is an annual charge, that through inadvertence was charged to account #5680 in 2006 and to account #5675 in 2007.

Account Grouping: 3950 – Taxes Other Than Income Taxes
As the Account Groupings Table sets out, the total variance between the 2007 Actual Expenses and the 2006 Actual Expenses is $3,189.

Acct # & Name	2007 Actual	2006 Actual	Variance
#6105 – Taxes Other Than Income Taxes	**$31,306**	**$34,495**	**-$3,189**

Explanation:
Due to inadvertence Capital Tax installment payments were allocated to Account #6105 in 2006. No Capital Tax installment payments were made in 2007. In addition, 2007 property taxes increased over 2006 expenses.

2008 Bridge year VS 2007 Actual

Total OM&A Expenses for the 2008 Bridge year are expected to increase $149,700 over 2007 actual year balances. The cost drivers for this increase are:

Labour/Burden Increase	$ 89,000
Office Supplies Increase	$ 16,400
Bad Debts Decrease	-$ 50,300
Outside Services Increase	$ 28,200
IT Expenses Increase	$ 20,500
Property Taxes/Lease Payments Increase	$ 20,200
Operations/Admin Net Increase	$ 25,700
TOTAL OM&A Increase	$149,700

In 2008, labour expense is expected to increase over 2008 levels due to the hiring of an additional manager in the operations department as a result of increased regulatory and safety requirements. In addition, the hourly staff compliment was increased in the engineering department. MPUC also had staff changeover in 2007 which would reduce the benefit expense in 2007 and 2008 until new staff reached fulltime status. Vehicle expense is projected to decrease in 2008 which would decrease the burden allocated to labour. Office Supplies are expected to increase due to changes in internet service providers, bank charges, etc. Outside Services will see an increase due to human resource consulting fees, regulatory and compliance requirements. IT Expenses are expected to increase due to a full year of costing with the Harris billing software. Bad debts are projected to decrease in 2008. Property taxes/lease payments will increase as a result of lease renewals and tax payments. Operations and Administration expenses will see general increases over 2007 levels. More detailed explanations for these increases are provided on the pages following.

Amortization Expense for the 2008 Bridge Year will also increase by $98,268 over 2007 Actual balances for a total Distribution Expense increase in the 2008 Bridge Year of $247,968 over 2007 Actual balances.

The following Account Groupings Table provides details of the total variances in each of the Account Groupings. Each of the Account Grouping sections are then analyzed per individual APH USoA Number for the OM&A Expense variances only. In addition, the materiality level is set as 1% of Total Distribution Expenses in each year.

Account Groupings Table

Account Grouping Description	**2008 Bridge Year**	**2007 Actual**	**Variance**
3500-Distribution Expenses - Operation	$392,900	$352,987	$39,913
3550-Distribution Expenses – Maintenance	$338,200	$283,582	$54,618
3650-Billing & Collecting	$420,400	$451,821	-$31,421
3700-Community Relations	$5,700	$15,073	-$9,373
3800-Administrative & General Expenses	$744,600	$650,232	$94,368
3950-Taxes Other than Income Taxes	$32,900	$31,306	$1,594
TOTAL OM&A Expenses	$1,934,700	$1,785,000	$149,700
Amortization	$622,181	$523,913	$98,268
Total Distribution Expenses	$2,556,881	$2,308,913	$247,968
Percent	1%	1%	
Threshold	$25,569	$23,089	

MPUC will use $23,089 as the Materiality Threshold in order to provide as much detail as possible in this analysis.

Account Grouping: 3500-Distribution Expenses – Operations

As the Account Groupings Table sets out, the total variance between 2008 Bridge Year and 2007 Actual Expenses in the Account Grouping 3500-Distribution Expenses – Operations provide for an increase of $39,913 which is made up of the following individual accounts:

Table 49 Distribution Expenses – Operations

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5005-Operation Supervision & Engineering	$253,600	$225,621	$27,979
#5010- Load Dispatching	$15,700	$15,066	$634
#5012-Station Buildings & Fixtures Expense	$62,800	$42,678	$20,122
#5016-Distribution Stn Equip Operation Labour	$8,400	$9,352	-$952
#5017-Distribution Stn Equip Supplies & Exp	$16,400	$18,890	-$2,490
#5065-Meter Expense	$11,600	$13,118	-$1,518
#5070-Customer Premises- Oper'n Labour	$22,300	$27,119	-$4,819
#5075-Customer Premises – Materials & Exp	$2,100	$1,143	$957
Total 3500-Distribution Expenses - Operation	**$392,900**	**$352,987**	**$39,913**

Those variances which exceed the materiality of $23,089 are explained as follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5005-Operation Supervision & Engineering	**$253,600**	**$225,621**	**$27,979**
Cost Drivers:			
Labour/Burden – increase			-$26,208
Subcontract – increase			-$3,280
Materials – decrease			$3,414
Training – increase			-$1,905
Total Unexplained Variance			0.00

Explanation:

In 2008, MPUC will be increasing staffing levels by one management position. This increased labour compliment is necessary to ensure the safety and other regulatory requirements are kept current with the changing business environment. MPUC is responding to the regulatory and safety needs by moving toward increasing and improving business practices and processes. These improvements and upgrades to its business practices will pay benefits in the long run and MPUC recognizes that there is a cost associated with achieving these benefits. MPUC is also undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. This management position will play an important role in the design and implementation of our capital plans. Included in Account #5005 in 2007 are costs associated with supervision by working foreman A which fluctuates depending on the type of work performed between Maintenance and Operations. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. These increases will account for the increase in labour/burden costs of $26,208.

MPUC shares after hours on-call with neighbouring LDC, Tay-Newmarket Hydro. The on-call expense fluctuates from year to year based on the number of callouts required. Materials Expenses are expected to decrease in 2008. Drafting supplies are expected to be reduced in 2008 and advertising costs which were posted to this account in 2007 will be allocated to #5620. Training in 2008 will increase as a result of the increase in staffing levels. It is expected that new staff will require regulatory and technical training.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality threshold of $23,089 have been explained above. Those variances of less than $23,089 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5010- Load Dispatching	**$15,700**	**$15,066**	**$634**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular APH USoA number, and in Account #5010 we are projecting labour/burden to decrease over the 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.

Material expenses are projected to increase over 2007 expenses as a result of increased SCADA and DESS software support fees, in addition to general material expense increases. The decrease in labour allocations coupled with the increase in material expenses will result in an overall increase of $634.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5012-Station Buildings & Fixtures Expense	**$62,800**	**$42,678**	**$20,122**

Explanation:

Property Taxes/Lease expenses are projected to increase over 2007 actual expenses due to property tax increases and the renegotiation of the leases and the new land lease required for the move of the 4th Street Substation. MPUC's lease was renewed in 2008 and has not received an increase in the lease costs since 2000.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5016-Distribution Stn Equip Oper'n Labour	**$8,400**	**$9,352**	**-$952**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5016 we are projecting labour/burden to decrease over the 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5017-Distribution Stn Equip Supplies & Exp	**$16,400**	**$18,890**	**-$2,490**

Explanation:
Substation maintenance expenses are projected to decrease over 2007 expenses. As noted previously, these costs include maintenance work performed by Rondar Engineering Inc. on our six distribution substations. Rondar performs maintenance inspections on MPUC's distribution substations on a two year rotation. In 2007 three of MPUC's substations had maintenance work performed, while in 2008 only two of the substations will require the yearly inspection and maintenance work, thus resulting in a decrease. Costs will vary depending on the needs as identified during the maintenance inspections, although one of the substations was fully upgraded in 2007, therefore yearly inspection and maintenance work are projected to be minimal in 2008.

In 2008 MPUC will pay for Meter Service Provider (MSP) Fees on each of our four registered wholesale metering points. Peterborough Utilities was retained as our Meter Service Provider (MSP), and handles our wholesale meter related issues with the IESO. In 2007 we completed the final meter point registration with the IESO. The increase represents the costs paid to Peterborough Utilities on the final metering point that was registered in 2007.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5065-Meter Expense	**$11,600**	**$13,118**	**-$1,518**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5065 we are projecting labour/burden to decrease over the 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5070-Customer Premises- Oper'n Labour	**$22,300**	**$27,119**	**-$4,819**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5065 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5075-Customer Premises – Materials & Exp	**$2,100**	**$1,143**	**$957**

Explanation:

It is expected that there will be fluctuations in material costs depending on the type of work performed at customer premises. Material expenses are projected to increase over 2007 expenses as a result of the general increase in cost of materials required for customer premise work.

Account Grouping: 3550-Distribution Expenses - Maintenance

As the Account Groupings Table sets out, the 2008 Bridge Year expenses are projected to be $54,618 higher than the 2007 Actual expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 50 Distribution Expenses - Maintenance

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5105 – Maintenance Supervision&Engineering	$64,500	$3,196	$61,304
#5110 - Maintenance Bldg/Fix – Dist'n Stations	$13,000	$12,405	$595
#5114 - Maintenance Dist Stn Equipment	$1,700	$1,869	-$169
#5120 – Maintenance Poles, Towers, Fixtures	$6,400	$6,436	-$36
#5125 – Maintenance Overhead Cond/Devices	$97,100	$119,533	-$22,433
#5135 – Overhead Dist Lines/Feeders –	$29,300	$30,185	-$885

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
ROW			
#5150 – Maintenance of U/G Conductors/De	$34,100	$34,601	-$501
#5160 – Maintenance of Line Transformers	$10,100	$14,012	-$3,912
#5175 – Maintenance of Meters	$82,000	$61,345	$20,655
Total 3500-Distribution Expenses - Operation	**$338,200**	**$283,582**	**$54,618**

Those variances which exceed the materiality of $23,089 are explained as follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5105-Maint. Supervision & Engineering	**$64,500**	**$3,196**	**$61,304**
Cost Drivers:			
Labour/Burden – increase			-$62,098
Other Expenses – decrease			$794
Total Unexplained Variance			0.00

Explanation:

In 2008, one of our outside workers was transferred into the engineering department and a new outside worker was hired. Consequently, labour/burden has increased for the full time position. Other expenses which include telephone and general maintenance expenses are projected to decrease by $794 over 2007 levels.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality threshold of $23,089 have been explained above. Those variances of less than $23,089 represent increases/decreases to the USoA numbers as follows;

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5110 - Maintenance Bldg/Fix – Dist'n Station	**$13,000**	**$12,405**	**$595**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5110 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Maintenance of Substations is projected to increase over 2007 expenses which allows for a moderate increase in snowplowing and lawn maintenance costs.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5114 - Maintenance Dist Stn Equipment	**$1,700**	**$1,869**	**-$169**

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5120 – Maintenance Poles, Towers, Fixtures	**$6,400**	**$6,436**	**-$36**

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5125-Maint. of Overhead Cond/Devices	**$97,100**	**$119,533**	**-$22,433**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5125 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses are also projected to decrease as a result of less labour hours being spent with respect to the maintenance of overhead conductors and devices. Training expenses are also projected to decrease over 2007 expenses.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5135-Overhead Distribution Lines & Feeders	**$29,300**	**$30,185**	**-$885**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5135 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material & Other expenses are projected to increase as a result of increased costs for chipping services MPUC's contracts out with respect to tree trimming work.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5150 – Maintenance of U/G Conductors/De	**$34,100**	**$34,601**	**-$501**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5150 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition,

hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Materials & Other expenses are projected to increase as a result of increased materials costs and contractor cost required to repair underground faults.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5160 – Maintenance of Line Transformers	**$10,100**	**$14,012**	**-$3,912**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5160 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses are also projected to decrease as a result of less labour hours being spent with respect to the maintenance of line transformers, and therefore less materials.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5175 – Maintenance of Meters	**$82,000**	**$61,345**	**$20,655**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5175 we are projecting labour/burden to increase over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. The

labour/burden component of Meter Maintenance for 2008 contains labour/burden for our Meter Technician. During the year some of the labour/burden is allocated to Meter Reading labour/burden Account #5310 and Customer Premises labour/burden Account #5070. For the purposes of this application, the Metering Technician labour/burden was allocated 100% to Account #5175. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses are projected to decrease as a result of lower miscellaneous materials required.

Account Grouping: 3650-Billing and Collecting

As the Account Groupings Table sets out, the 2008 Bridge Year expenses are projected to be $31,421 lower than the 2007 Actual expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 51 Billing and Collecting

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5310 – Meter Reading Expense	$96,000	$106,036	-$10,036
#5315 – Customer Billing	$176,900	$155,253	$21,647
#5320 – Collecting	$66,700	$59,968	$6,732
#5325 – Cash Over and Short	$200	-$249	$449
#5330 – Collection Charges	$600	$469	$131
#5335 – Bad Debt Expense	$80,000	$130,344	-$50,344
Total 3550-Billing & Collecting	**$420,400**	**$451,821**	**-$31,421**

Those variances which exceed the materiality threshold of $23,089 are explained as follows:

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5335 – Bad Debt Expense	**$80,000**	**$130,344**	**-$50,344**
Cost Drivers:			
Commercial - decrease			$50,344
Total Unexplained Variance			0.00

Explanation:

In 2006 and 2007 MPUC had two General Service Customers declare bankruptcy. MPUC followed the OEB regulatory requirements in dealing with these customers. MPUC was not able to collect deposits from these customers prior to their bankruptcy as both customers had excellent payment history and were grandfathered into the new rules at the time of incorporation of MPUC. MPUC has therefore set its bad debt expense at $80,000 per year. Since market opening the business cycle has been on the rise and we are just now starting a business downturn. MPUC feels that other businesses in its service territory may be at risk as manufacturers struggle with the economy. In order to mitigate these risks MPUC is diligent in ensuring prompt payment, however, should a customer declare bankruptcy or file for protection, MPUC has already suffered sufficient losses in that our billing process is already up to 6 weeks behind the day of consumption. The following is a schedule outlining the bad debt balances from 2003 to 2007:

	2003	**2004**	**2005**	**2006**	**2007**
Bad Debts	$28,281	$31,942	$63,312	$78,167	$130,344
Allowance For Doubtful Accounts	$76,272	$77,241	$40,000	$80,000	$80,000

Account variances that exceeded the materiality of $23,089 have been explained above. Those variances of less than $23,089 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5310 – Meter Reading Expense	**$96,000**	**$106,036**	**-$10,036**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5310 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.

As noted above in account #5175 the labour/burden component of Meter Maintenance for 2008 contains labour/burden for our Meter Technician. During the year some of the labour/burden is allocated to Meter Reading labour/burden Account #5310. For the purposes of this application, the Metering Technician labour/burden was allocated 100% to Account #5175. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Meter Reading Contract expenses are also projected to have a small decrease.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5315 – Customer Billing	**$176,900**	**$155,253**	**$21,647**

Explanation:
Customer Billing labour/burden expenses are projected to increase year over year in accordance with the Collective Bargaining Agreement. Office supplies include a minimal increase to allow for supply cost increases during the year. Postage expenses are also projected to increase to allow for a increase in postage rates. IT expenses have a projected increase to account for a full year of IT services in 2008. MPUC converted to the Harris Biling System in May 2007, therefore the IT services were not provided for a full year in 2007. Training expenses are projected to decrease. Training will be required when we upgrade our Harris Billing System to the windows based version of the software. These training requirements will be less than the training required for billing staff in 2007 due to the staffing change in 2007. Additional training was required for the new staff member in 2007 which will not be required in 2008. Therefore the training expense for billing staff will decrease in 2008.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5320 – Collecting	**$66,700**	**$59,968**	**$6,732**

Explanation:
Collecting labour/burden expenses are projected to increase as a result of regular yearly salary increases year over year. Other expenses include an increase to allow for supply cost increases (printing costs, collection notices) during the year. Training expenses are projected

to increase to account for training required when we upgrade Harris Billing System to the windows based version of the software.

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5325 – Collecting – Cash Over and Short	**$200**	**-$249**	**$449**

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5330 – Collection Charges	**$600**	**$469**	**$131**

Account Grouping: 3700-Community Relations

As the Account Groupings Table sets out, the 2008 Bridge Year expenses are projected to be $9,373 lower than the 2007 Actual expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 52 Community Relations

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5410 – Community Relations – Sundry	$5,700	$6,675	-$975
#5415 – Energy Conservation	$0	$8,398	-$8,398
Total 3700 – Community Relations	**$5,700**	**$15,073**	**-$9,373**

No Variances exceed the materiality threshold of $23,089. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	**2008 Bridge Year**	**2007 Actual**	**Variance**
#5410 – Community Relations – Sundry	**$5,700**	**$6,675**	**-$975**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5410 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material expenses are also projected to decrease as a result of less labour hours being spent with respect to community relations, and therefore less material requirements.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5415 – Energy Conservation	**$0**	**$8,398**	**-$8,398**

Explanation:

In 2007 MPUC expenses relating to the Third Tranche CDM programs were allocated to account #5415 Energy Conservation in accordance with the direction received from the Ontario Energy Board. The Third Tranche funds were fully allocated to the approved programs in 2007 and accordingly, no expenses have been projected for 2008.

Account Grouping: 3800-Administrative and General Expenses

As the Account Groupings Table sets out, the 2008 Bridge Year expenses are projected to be $94,368 higher than the 2007 Actual expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 53 Administrative and General Expenses

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5605 – Executive Salaries & Expenses	$27,600	$27,557	$43
#5610 – Management Salaries & Expenses	$284,000	$259,839	$24,161
#5615 – General Admin. Salaries & Expenses	$66,400	$ 63,265	$3,135
#5620 – Office Supplies & Expenses	$105,800	$89,407	$16,393
#5630 – Outside Services Employed	$73,200	$44,968	$28,232
#5635 – Property Insurance	$21,000	$19,432	$1,568
#5640 – Injuries & Damages	$21,100	$21,969	-$869
#5655 – Regulatory Expenses	$23,700	$21,059	$2,641
#5665 – Miscellaneous General Expenses	$28,500	$28,092	$408
#5675 – Maintenance of General Plant	$88,700	$70,957	$17,743
#5680 – Electrical Safety Authority Fees	$4,600	$3,685	$915
Total 3800-Administrative&General Expenses	**$744,600**	**$650,232**	**$94,368**

Those variances which exceed the materiality of $23,089 are explained as follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5610 – Management Salaries & Expenses	**$284,000**	**$259,839**	**$24,161**
Cost Drivers:			
Labour/Burden – increase			-$20,414
Training – increase			-$3,747
Total Unexplained Variance			0.00

Explanation:

In 2007, management salaries included one management position at the probationary level for part of the year. In 2008, management salaries increased as a result of one manager moving from probationary to fulltime status and moving to the next step increase for the full year, in addition to other management moving to the next step increases. Burden will increase as a result of the increases in salaries. Training is expected to increase in 2008 as a result of Harris software training and management professional development.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5630 – Outside Services Employed	**$73,200**	**$44,968**	**$28,232**
Cost Drivers:			
Legal, Audit Fees – increase			-$218
Consulting Fees – increase			-$27,714
Safety Audit Fees – increase			-$300
Total Unexplained Variance			0.00

Explanation:

An increase of $218 is projected as an increase for legal and audit fees in the 2008 Bridge Year over 2007 actual balances. Consulting fees are expected to increase $12,714 as a result of the increased need for regulatory and safety compliance work, while safety audit fees are projected to increase by $300. 2008 Bridge Year consulting fees for business and human resource related functions are projected to increase expenses $15,000 over 2007.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality threshold of $23,089 have been explained above. Those variances of less than $23,089 represented increases/decreases to the USoA numbers as follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5605 – Executive Salaries & Expenses	**$27,600**	**$27,557**	**$43**

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5615 – General Admin. Salaries & Expenses	**$66,400**	**$63,265**	**$3,135**

Explanation:

2008 labour/burden expenses are projected to decrease. In 2007 labour/burden expenses increased due to a full time staff member being off on sick leave in the winter of 2007 for approx. 6 weeks. Temporary staff were hired during the sick leave. This additional expense has not been projected for 2008. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Retiree benefits are projected to increase in 2008 over 2007 expenses as a result of increases in premiums for the year. Training expenses are projected increase to account for training required when we upgrade our Harris Billing System to the windows based version of the software.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5620 – Office Supplies & Expenses	**$105,800**	**$89,407**	**$16,393**

Explanation:

Office supply increases are projected to increase due to additional charges for internet access as a result of the change in internet services due to the Harris conversion, bank charges, general office supply increases and software support increases.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5635 – Property Insurance	**$21,000**	**$19,432**	**$1,568**

Explanation:

Property insurance rates are projected to increase 2008, over 2007 expenses.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5640 – Injury & Damages	**$21,100**	**$21,969**	**-$869**

Explanation:

Injury & Damage Insurance rates are projected to decrease over 2007 expenses as 2007 expenses included and additional claim coupled with a decrease in premiums in 2007.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5655 – Regulatory Expenses	**$23,700**	**$21,059**	**$2,641**

Explanation:

2008 Regulatory expenses are projected to increase over 2007 expenses, as a result of increased regulatory fees paid to the OEB and cost awards paid to the OEB with respect to various board consultations.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5665 – Miscellaneous General Expenses	**$28,500**	**$28,092**	**$408**

Explanation:

Membership fees are projected to increase over 2007 expenses. Minimal increases have been projected for Cornerstone Hydro Electric Concepts (CHEC), Electricity Distributors Association (EDA), and Utility Standards Forum (USF) membership fees. Miscellaneous membership fees are projected to decrease by $1,173 as a result of AccPac software support fees inadvertently being posted to account #5665 in 2007. In 2008 these fees have been posted to account #5620 Office Supplies and Expenses.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5675 – Maintenance of General Plant	**$88,700**	**$70,957**	**$17,743**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5675 we are projecting labour/burden to decrease over 2007 expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Wireless expenses are projected to increase over 2007 expenses. Other plant expenses are projected to increase over 2007 expenses as a result of increased costs associated with emergency telephone access, snowplowing and general plant material and utility increases.

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#5680 – Electrical Safety Authority Fees	**$4,600**	**$3,685**	**$915**

Explanation:
ESA fees are projected to increase over 2007 expenses as a result of increasing Regulatory Oversight Costs billed to LDC's.

Account Grouping: 3950 – Taxes Other Than Income Taxes
As the Account Groupings Table sets out, the 2008 Bridge Year expenses are projected to be $1,594 higher than the 2007 Actual expenses. This amount is made up of increases to Account #6105 as a result of an increase in property taxes for the 2008 year ass follows:

Acct # & Name	2008 Bridge Year	2007 Actual	Variance
#6105 – Taxes Other Than Income Taxes	**$32,900**	**$31,306**	**$1,594**

2009 Test Year VS 2008 Bridge Year

Total OM&A Expenses for the 2009 Test Year are expected to increase $158,400 over the 2008 Bridge Year balances. The cost drivers for this increase are:

Labour/Burden Increase	$ 92,100
Regulatory Rate Application Exp Increase	$ 50,000
Operations/Admin General Exp Increases	$ 16,300
TOTAL OM&A Increase	$158,400

In 2009, labour expense will be increased as the managerial costs are borne for a full year. Regulatory expenses will increase due to costs incurred as a result of this rate application. General operations and administration expenses are expected to increase over 2008 due to inflation. More detailed explanations for these increases are provided on the pages following.

Amortization Expense for the 2009 Test Year will also increase by $113,243 over the 2008 Bridge year balances for a total Distribution Expense increase in the 2009 Test Year of $271,643 over 2008 Bridge Year balances.

The following Account Groupings Table provides details of the total variances in each of the Account Groupings. Each of the Account Grouping sections are then analyzed per individual APH USoA Number for the OM&A Expense variances only. In addition, the materiality level is set as 1% of Total Distribution Expenses in each year.

Account Groupings

Account Grouping Description	2009 Test Year	2008 Bridge Year	Variance
3500-Distribution Expenses – Operation	$455,700	$392,900	$62,800
3550-Distribution Expenses – Maintenance	$353,900	$338,200	$15,700

Account Grouping Description	2009 Test Year	2008 Bridge Year	Variance
3650-Billing & Collecting	$435,800	$420,400	$15,400
3700-Community Relations	$5,600	$5,700	-$100
3800-Administrative & General Expenses	$807,900	$744,600	$63,300
3950-Taxes Other than Income Taxes	$34,200	$32,900	$1,300
TOTAL OM&A Expenses	$2,093,100	$1,934,700	$158,400
Amortization	$735,424	$622,181	$113,243
Total Distribution Expenses	$2,828,524	$2,556,881	$271,643
Percent	1%	1%	
Threshold	$28,285	$25,569	

MPUC will use $25,569 as the Materiality Threshold in order to provide as much detail as possible in this analysis.

Account Grouping: 3500-Distribution Expenses – Operations

As the Account Groupings Table sets out, the total variance between 2009 Test Year and 2008 Bridge Year Expenses in the Account Grouping 3500-Distribution Expenses – Operations provide for an increase of $62,800 which is made up of the following individual accounts:

Table 54 Distribution Expenses – Operations

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5005-Operation Supervision & Engineering	$314,900	$253,600	$61,300
#5010- Load Dispatching	$16,000	$15,700	$300
#5012-Station Buildings & Fixtures Expense	$64,000	$62,800	$1,200
#5016-Distribution Stn Equip Operation Labour	$8,200	$8,400	-$200
#5017-Distribution Stn Equip Supplies & Exp	$17,000	$16,400	$600
#5065-Meter Expense	$11,400	$11,600	-$200
#5070-Customer Premises- Oper'n Labour	$22,100	$22,300	-$200
#5075-Customer Premises – Materials & Exp	$2,100	$2,100	$0
Total 3500-Distribution Expenses - Operation	**$455,700**	**$392,900**	**$62,800**

Those variances which exceed the materiality threshold of $25,569 are explained as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5005-Operation Supervision & Engineering	**$314,900**	**$253,600**	**$61,300**
Cost Drivers:			
Labour/Burden – increase			-$61,300
Total Unexplained Variance			0.00

Explanation:
As indicated in the 2008 analysis, MPUC will be increasing staffing levels by one management position. This increased labour compliment is necessary to ensure the safety and other regulatory requirements are kept current with the changing business environment. MPUC is responding to the regulatory and safety needs by moving towards increasing and improving business practices and processes. These improvements and upgrades to its business practices will pay benefits in the long run and MPUC recognizes that there is a cost associated with achieving these benefits. MPUC is also undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. This management position will play an important role in the design and implementation of our capital plans.

This position will be hired in the fall of 2008. The increase in the 2009 Test Year is a result of a full year of labour/burden for the new position, as compared to a partial year in the 2008 Bridge Year. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. This increase in staff compliment will account for the increase in labour/burden costs of $61,300.

Reconciliation to Account Groupings Table:
Account variances that exceeded the materiality of $25,569 have been explained above. Those variances less than $25,569 represent increase/decreases to the USoA numbers as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5010- Load Dispatching	**$16,000**	**$15,700**	**$300**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5012-Station Buildings & Fixtures Expense	**$64,000**	**$62,800**	**$1,200**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5012 we are projecting labour/burden to decreased over the 2008 projected expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition however, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Consequently, 2009 will see an overall increase of $1,200.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5016-Distribution Stn Equip Oper'n Labour	**$8,200**	**$8,400**	**-$200**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5017-Distribution Stn Equip Supplies & Exp	**$17,000**	**$16,400**	**$600**

Explanation:

We have projected an increase in Substation Maintenance Expenses and an increase in Meter Service Provider Costs over 2008 expenses, which allow for moderate increases in each of these service areas.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5065-Meter Expense	**$11,400**	**$11,600**	**-$200**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5070-Customer Premises- Oper'n Labour	**$22,100**	**$22,300**	**-$200**

Account Grouping: 3550-Distribution Expenses - Maintenance

As the Account Groupings Table sets out, the 2009 Test Year expenses are projected to be $15,700 higher lower than the 2008 Bridge Year expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 55 Distribution Expenses - Maintenance

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5105 – Maintenance Supervision&Engineering	$77,200	$64,500	$12,700
#5110 - Maintenance Bldg/Fix – Dist'n Stations	$13,400	$13,000	$400
#5114 - Maintenance Dist Stn Equipment	$1,600	$1,700	-$100
#5120 – Maintenance Poles, Towers, Fixtures	$6,600	$6,400	$200
#5125 – Maintenance Overhead Cond/Devices	$95,900	$97,100	-$1,200
#5135 – Overhead Dist Lines/Feeders – ROW	$29,300	$29,300	$0
#5150 – Maintenance of U/G Conductors/De	$33,800	$34,100	-$300
#5160 – Maintenance of Line Transformers	$9,900	$10,100	-$200
#5175 – Maintenance of Meters	$86,200	$82,000	$4,200
Total 3500-Distribution Expenses - Operation	**$353,900**	**$338,200**	**$15,700**

No variances exceed the materiality level of $25,569. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5105-Maint. Supervision & Engineering	**$77,200**	**$64,500**	**$12,700**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5105 we are projecting labour/burden to increase over the 2008 projected expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Other expenses for 2009 are projected to increase which will allow for a moderate increase in costs.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5110 - Maintenance Bldg/Fix – Dist'n Station	**$13,400**	**$13,000**	**$400**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5114 - Maintenance Dist Stn Equipment	**$1,600**	**$1,700**	**-$100**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5120 – Maintenance Poles, Towers, Fixtures	**$6,600**	**$6,400**	**$200**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5125-Maint. of Overhead Cond/Devices	**$95,900**	**$97,100**	**-$1,200**

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5125 we are projecting labour/burden to decrease over the 2008 projected expenses. The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.

Material expenses are projected to increase to allow for moderate increases in material costs over the year.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5150 – Maintenance of U/G Conductors/De	**$33,800**	**$34,100**	**-$300**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5160 – Maintenance of Line Transformers	**$9,900**	**$10,100**	**-$200**

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5175 – Maintenance of Meters	**$86,200**	**$82,000**	**$4,200**

Explanation:
It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5175 we are projecting labour/burden to increase over 2008 projected expenses. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Material expenses are projected to increase to allow for moderate increases in materials and other expenses.

Account Grouping: 3650-Billing and Collecting
As the Account Groupings Table sets out, the 2009 Test Year expenses are projected to be $15,400 higher than the 2008 Bridge Year expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 56 Billing and Collecting

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5310 – Meter Reading Expense	$96,000	$96,000	$0
#5315 – Customer Billing	$190,300	$176,900	$13,400
#5320 – Collecting	$68,700	$66,700	$2,000
#5325 – Cash Over and Short	$200	$200	$0
#5330 – Collection Charges	$600	$600	$0
#5335 – Bad Debt Expense	$80,000	$80,000	$0
Total 3550-Billing & Collecting	**$435,800**	**$420,400**	**$15,400**

No variances exceed the materiality level of $25,569. The above variances represent increases/decreases to the USoA numbers as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5315 – Customer Billing	**$190,300**	**$176,900**	**$13,400**

Explanation:
Customer Billing labour/burden expenses are projected to increase due to billing staff member progressing to the next level in their wage category. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Office supplies include a minimal increase to allow for supply cost increases during the year, while postage expenses are also projected to increase to allow for an increase in postage rates. IT expenses are projected to increase over 2008 projected expenses to allow for increases in costs.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5320 – Collecting	**$68,700**	**$66,700**	**$2,000**

Explanation:
Collecting labour/burden expenses are projected to increase over 2008 projected expenses in accordance with the Collective Bargaining Agreement. Material expenses are projected to increase over 2008 projected expenses to allow for moderate increases in collection related supply costs.

Account Grouping: 3700-Community Relations

As the Account Groupings Table sets out, the 2009 Test Year expenses are projected to be $100 lower than the 2008 Bridge Year expenses. This amount is made up of a decrease to Account 5410 as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5410 – Community Relations – Sundry	$5,600	$5,700	-$100
Total 3700 – Community Relations	**$5,600**	**$5,700**	**-$100**

Account Grouping: 3800-Administrative and General Expenses

As the Account Groupings Table sets out, the 2009 Test Year expenses are projected to be $63,600 higher than the 2008 Bridge Year expenses. This amount is made up of increases and decreases to individual APH accounts as follows:

Table 57 Administrative and General Expenses

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5605 – Executive Salaries & Expenses	$27,600	$27,600	$0
#5610 – Management Salaries & Expenses	$285,900	$284,000	$1,900
#5615 – General Admin. Salaries & Expenses	$70.400	$66,400	$4,000
#5620 – Office Supplies & Expenses	$107,800	$105,800	$2,000
#5630 – Outside Services Employed	$75,400	$73,200	$2,200
#5635 – Property Insurance	$21,600	$21,000	$600
#5640 – Injuries & Damages	$21,700	$21,100	$600
#5655 – Regulatory Expenses	$73,700	$23,700	$50,000
#5665 – Miscellaneous General Expenses	$28,500	$28,500	$0
#5675 – Maintenance of General Plant	$90,600	$88,700	$1,900
#5680 – Electrical Safety Authority Fees	$4,700	$4,600	$100
Total 3800-Administrative&General Expenses	**$807,900**	**$744,600**	**$63,300**

Those variances which exceed the materiality threshold of $25,569 are explained as follows:

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5655 – Regulatory Expenses	**$73,700**	**$23,700**	**$50,000**
Cost Drivers:			
OEB Regulatory Fees – increase			-$50,000
Total Unexplained Variance			0.00

Explanation:

MPUC expects to incur costs from the Ontario Energy Board as a result of the 2009 Rate Application process. These costs include supporting the review process of the application which could include a technical or oral hearing, along with intervener and other cost awards and are expected to total $150,000. MPUC has included only $50,000 in this Rate Application expecting recovery over three years.

Reconciliation to Account Groupings Table:

Account variances that exceeded the materiality threshold of $25,569 have been explained above. Those variances of less than $25,569 represent increases/decreases to the USoA numbers as follows:

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5610 – Management Salaries & Expenses	**$285,900**	**$284,000**	**$1,900**

Explanation:

Management labour/burden expenses are projected to increase over 2008 projected expenses to allow for annual increases in labour/burden of $1,900.

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5615 – General Admin. Salaries & Expenses	**$70,400**	**$66,400**	**$4,000**

Explanation:

General Administrative labour/burden expenses are projected to increase over 2008 projected expenses to allow for increases that occur year over year in accordance with the Collective Bargaining Agreement.. Retiree benefits are expected to increase over 2008 levels.

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5620 – Office Supplies & Expenses	**$107,800**	**$105,800**	**$2,000**

Explanation:
Office supply increases are projected to increase over 2008 projected expenses to allow for general cost increases over the year.

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5630 – Outside Services Employed	**$75,400**	**$73,200**	**$2,200**

Explanation:
Consulting Fees for 2009 are projected to increase over 2008 projected expenses to allow for general cost increases associated with accounting, legal and general consulting fees.

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5635 – Property Insurance	**$21,600**	**$21,000**	**$600**

Explanation:
Property Insurance expenses are projected to increase by $600 over 2008 projected expenses based on historical cost increases.

Acct # & Name	**2009 Test Year**	**2008 Bridge Year**	**Variance**
#5640 – Injury & Damages	**$21,700**	**$21,100**	**$600**

Explanation:
Injury & Damage Insurance expenses are projected to increase by $600 over 2008 projected expenses based on historical cost increases.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5675 – Maintenance of General Plant	**$90,600**	**$88,700**	**$1,900**

Explanation:
Maintenance of General Plant Expenses are projected to increase over 2008 projected expenses to allow for general cost increases including cleaning, snow removal, yard maintenance and utility charges over the year.

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#5680 – Electrical Safety Authority Fees	**$4,700**	**$4,600**	**$100**

Account Grouping: 3950 – Taxes Other Than Income Taxes
As the Account Groupings Table sets out, the 2009 Test Year expenses are projected to be $1,300 higher than the 2008 Bridge Year expenses. This amount is attributed to an increase in property taxes in 2009 as follows:

Acct # & Name	2009 Test Year	2008 Bridge Year	Variance
#6105 – Taxes Other Than Income Taxes	**$34,200**	**$32,900**	**$1,300**

Materiality Analysis on OM&A Costs

The calculation of the Materiality Threshold on OM&A Costs is shown in the following table:

	EDR – 2006	**Actual - 2006**	**Actual – 2007**	**Bridge – 2008**	**Test - 2009**
OM&A Expenses	$1,708,695	$1,803,182	$1,785,000	$1,934,700	$2,093,100
Amortization	$ 435,963	$ 497,831	$ 523,913	$ 622,181	$ 735,424
Total Distribution Expenses	$2,144,658	$2,301,013	$2,308,913	$2,556,881	$2,828,524
Percent	1%	1%	1%	1%	1%
Threshold	$21,447	$23,010	$23,089	$25,569	$28,285

Shared Services

MPUC does not share services.

Service Agreement(s)

Not Applicable.

Corporate Cost Allocation

Not Applicable.

Purchase of Services

Name of Company	Amount	Summary of Nature of Activity	Cost or Contract Approach
ACCOUNTING PLUS	$8,381	Temporary office support	cost approach
ADVANCED UTILITY SYSTEMS	$5,035	Billing Software sales & service	cost approach
ALTEC INDUSTRIES LTD.	$140,355	Truck Maintenance; truck purchase	cost approach
ArevaT & D Canada Inc	$319,219	Sub Station Equipment	cost approach
BARKLEY TECHNOLOGIES	$5,300	44KV system work	cost approach
BARRIE HYDRO DISTRIBUTION INC	$5,830	On Call service	cost approach
BDO DUNWOODY	$27,772	Auditor	cost approach
BEL VOLT SALES LTD	$18,177	Crossarms / switches etc	cost approach
CANADIAN ELECTRIC SERVICE	$95,612	Transformer Purchases	cost approach
COMPU-SOLVE TECHNOLOGIES	$38,338	Computer purchases & support	cost approach
DAVID FOURNIER	$5,050	Contractor - general maintenance	cost approach
DAVID WINTER	$5,344	Business services - Consultant	cost approach
DEE'S ENTERPRISES	$13,568	Steel Building Construction	cost approach
FIRST FOR SAFETY	$8,572	Safety supplies & Training	cost approach
G & M CONTRACTING	$7,864	building & substation maintenance	cost approach
GARRAWAY'S ELECTRICAL SERVICES	$10,115	electrical service	cost approach
GLOBAL RENTAL CANADA ULC	$23,256	equipment rental	cost approach
GRAFTON UTILITY SUPPLY	$187,685	Inventory purchases	cost approach
GUELPH UTILITY POLE COMPANY LD	$31,163	Hydro poles	cost approach
HAPAMP ELMVALE LTD	$69,392	Excavator	cost approach
HARRIS COMPUTER UTILITY	$116,446	Billing; conversion costs; training	cost approach
LAKEPORT POWER LTD	$74,136	Transformer Purchases	cost approach
LENBY BUSINESS FORMS	$10,207	Office stationery	cost approach
LISA'S CLEANING SERVICE	$5,750	Office cleaning	cost approach
McNAMARA POWERLINE CONST	$175,793	powerline construction	cost approach
MORDEN CONSTRUCTION	$25,779	snow removal	cost approach
NORAMCO ELECTRICAL	$29,249	wire	cost approach
OAKVILLE HYDRO ENERGY SER INC	$7,790	Meters	cost approach
OLAMETER INC	$62,669	Meter reading / notice delivery	contract
PIONEER STEEL BUILDINGS LTD	$18,152	steel building installation	cost approach
RONA	$6,177	supplies	cost approach
RONDAR INC	$200,696	Engineering services for sub stns	cost approach
S&C ELECTRIC CANADA LTD.10	$16,194	inventory parts	cost approach
SAFE-WAY TREE SERVICE	$7,871	tree trimming	cost approach
SHEPHERDS UTILITY EQUIPMENT	$21,411	inventory parts	cost approach
SOLUTION PROVIDER NETWORK INC	$5,054	AccPac support	cost approach
Stress Crete Limited	$8,792	poles concrete	cost approach

Name of Company	Amount	Summary of Nature of Activity	Cost or Contract Approach
STURDY POWER LINES LTD	$12,284	44KV line installation	cost approach
SURVALENT TECHNOLOGY	$135,629	SCADA - Engineering	cost approach
THE DRAFTING CLINIC CANADA LTD	$9,336	Engineering service	cost approach
THE ITM GROUP INC	$21,175	software support; conversion costs	contract
THE SARGEANT CO LTD.	$18,941	vehicle fuel purchases	cost approach
THE SPI GROUP	$8,623	hub support	contract
TILTRAN SERVICES	$17,271	ground grid installation	cost approach
TOWN OF MIDLAND	$84,828	truck maintenance; ppty taxes	cost approach
TRENCHLESS UTILITY EQUIPMENT	$6,654	construction service	cost approach
Util-Assist	$26,583	CIS conversion	contract
UTILISMART CORPORATION	$49,659	billing interval and NSL reading	contract
UTILITY COLLABORATIVE SERVICES	$60,976	licenses - Harris; billing fees	contract

Employee Description

Number of Employees:

Description		2006 EDR	2006 Actual		2007 Actual		2008 Bridge		2009 Test	
Management		3	5.8		5.5		5.5		6	
Union		13	9		9.1		10.25		10	

Compensation (Salary and Wages):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Bridge	Average	2009 Test	Average
Management		$61,387	$358,796	$61,861	$344,229	$62,587	$372,000	$67,636	$423,400	$70,567
Union		$45,676	$461,863	$51,318	$483,963	$53,183	$568,100	$55,424	$616,600	$61,660

Compensation (Benefits):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Bridge	Average	2009 Test	Average
Management		$16,881	$89,665	$15,460	$88,356	$16,065	$102,290	$18,598	$121,475	$20,246
Union		$12,405	$108,612	$12,068	$107,838	$11,850	$148,962	$14,533	$165,198	$16,520

Compensation (Incentives):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Bridge	Average	2009 Test	Average
Management	$15,000	$ 5,000	$22,500	$3,879	$52,300	$9,509	$33,900	$6,163	$25,000	$4,167

Total (Salary and Wages, Benefits & Incentives):

Description	2006 EDR	Average	2006 Actual	Average	2007 Actual	Average	2008 Bridge	Average	2009 Test	Average
Management		$83,268	$470,961	$81,200	$484,885	$88,161	$508,190	$92,397	$569,875	$94,980
Union		$58,081	$570,474	$63,386	$591,801	$65,033	$717,062	$69,957	$781,798	$78,180

Costs Charged to OM&A:

	2006 Actual		2007 Actual		2008 Bridge		2009 Test	
	$950,782		$858,620		$975,662		$1,089,684	

Note: The 2006 Rate Handbook states the following:

“Where there are three, or fewer, full-time equivalents (FTEs) in any category, MPUC may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs”

In compliance with the above, MPUC has aggregated information relating to the executive and management class into the management class.

MPUC contributes to the Ontario Municipal Employee Retirement System (OMERS), a defined benefit pension plan for employees. As MPUC is only liable for the contributions, defined contribution plan accounting is used. MPUC's contribution to the pension fund for the employee's current service for the year ended December 31, 2007 was $60,515.

An incentive plan is provided to management employees based on cost reduction, safety and adherence to service quality indicators. The performance measures include reducing expenses – ratepayers will benefit as costs are reduced in the form of reduced rates. Exceeding OEB SQI requirements – ratepayers will benefit in customer service related areas as well as in service reliability. Adherence to safety standards – Ratepayers will benefit as MPUC performs its work in a safe and controlled environment taking all necessary forms of safety precautions. Ratepayers also benefit in WSIB premium reductions and in the reduction of lost productivity.

Loss Adjustment Factor Calculation

		2002	2003	2004	2005	2006	2007
A	"Wholesale kWh (IESO)/HONI	226,980,813	231,773,560	233,658,455	238,157,129	234,992,610	232,327,828
B	Wholesale kWh for Large Use Customers (IESO)	0	0	0	0	0	0
C	Net Wholesale kWh (A)-(B)	226,980,813	231,773,560	233,658,455	238,157,129	234,992,610	232,327,828
D	Retail kWh (Distributor)	215,110,819	224,245,319	227,207,629	233,239,879	225,666,128	224,566,924
E	Retail kWh for Large Use Customers (1% Loss)	0	0	0	0	0	0
F	Net "Retail" kWh (D)-(E)	215,110,819	224,245,319	227,207,629	233,239,879	225,666,128	224,566,924
G	Loss Factor (C/F)	1.0552	1.0336	1.0284	1.0211	1.0413	1.0346
H	Distribution Loss Adjustment Factor (5 year average)						1.0318
	Distribution Loss Adjustment Factor (4 year average)						1.0313
	Distribution Loss Adjustment Factor (4 year average – no 2006)						1.0294

Total Utility Loss Factor	5 yr Av	4 Yr Av	4 Yr Av – no 2006
Supply Facility Loss Factor	1.0340	1.0340	1.0340
Total Loss Factor Secondary Metered Customers <5,000 kW	1.0669	1.0664	1.0644
Primary Metered Customers <5,000 kW	1.0562	1.0557	1.0538

MPUC is not proposing to increase the distribution loss factor. In 2006, one of MPUC's metering points read by Hydro One was malfunctioning. As a result consumption was estimated based on historical information from Hydro One. Although this metering point makes up less than 10% of MPUC's total consumption, there is no other apparent reason why the losses increased in 2006. As the above-noted analysis shows, if 2006 was taken out of the calculation, the loss factor would have been 1.0644. The loss factor with the 2006 consumption is 1.0669. MPUC's current loss factor is 1.0651 which is between the two calculations. MPUC believes that the current loss factor is a better representation of losses and consequently is not requesting an increase in the loss factor in this Rate Application.

2007 Explanation of Loss >5%

The supply loss factor has increased from Hydro One from 1.0329 in 2004 to 1.034 in 2007. Taking the 1.0329 x the DLF of 1.0318 would have resulted in a TLF of 1.0657.

Detail Action Plan for Losses (Past and Future)

Through the substation upgrades, infrared studies and capital upgrades MPUC will continue to work toward reducing losses in our distribution system. The capital plans have been outlined in Exhibit 2 of this Rate Application. Infrared studies were done in 2006 and hot spots have been identified and appropriate action has been taken. Pole line upgrades in the past and future years will also reduce losses.

Details of Total Losses

	2002	2003	2004	2005	2006	2007
"Wholesale kWh (IESO)/HONI	226,980,813	231,773,560	233,658,455	238,157,129	234,992,610	232,327,828
Retail kWh (Distributor)	215,110,819	224,245,319	227,207,629	233,239,879	225,666,128	224,566,924
Net Losses	11,869,994	7,528,241	6,450,826	4,917,250	9,326,482	7,760,904

Variance and Materiality Analysis on Distribution Losses

Please find below the variance analysis on MPUC's Loss Adjustment factor for the period of 2003 to 2007.

2003	2004	2005	2006	2007
1.0336	1.0284	1.0211	1.0413	1.0346

Proposed 2009

MPUC attests that its method of determining it's proposed loss adjustment factor is consistent with the methodology set out in section 10-5 of the 2006 EDR Handbook. MPUC is not proposing to increase the distribution loss factor. In 2006, one of MPUC's metering points read by Hydro One was malfunctioning. As a result consumption was estimated based on historical information from Hydro One. Although this metering point makes up less than 10% of MPUC's total consumption, there is no other apparent reason why the losses increased in 2006. As the above-noted analysis shows, if 2006 was taken out of the calculation, the loss factor would have been 1.0644. The loss factor with the 2006 consumption is 1.0669. MPUC's current loss factor is 1.0651 which is between the two calculations. MPUC believes that the current loss factor is a better representation of losses and consequently is not requesting an increase in the loss factor in this Rate Application.

Retail Transmission Adjustment Calculations

MPUC has not made any change to it's retail transmission rates in this Application. MPUC is aware that Hydro One has made application to the Ontario Energy Board on May 30, 2008 to adjust uniform transmission rates effective January 1, 2009 under Board File number EB-2008-0113. Once an Order has been made by the Ontario Energy Board, MPUC will make the appropriate adjustments to its transmission rates in this Application.

Income and Capital Taxes

Tax Calculations Overview

Attached on the pages following this page are the following Tables:

Undepreciated Capital Costs Table

Cumulative Eligible Capital Table

Interest Expense Table

Loss Carryforward Table

Reserve Balances Table

Taxable Income Table

Capital Tax Table

Total PILS ExpenseTable

The above-noted schedules provide a detailed calculation of PILS for the 2006 Actual, 2008 Bridge Year and 2009 Test years.

P1 Undepreciated Capital Costs (UCC)

Class	Description	UCC Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC 2008 Opening Balance	2008 Projected Additions	2008 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %
1	Distribution System - post 1987	5,628,860			**5,628,860**	23,200		5,652,060	11,600	5,640,460	4.0%
2	Distribution System - pre 1988										6.0%
8	General Office/Stores Equip	191,365			**191,365**	61,840		253,205	30,920	222,285	20.0%
10	Computer Hardware/ Vehicles	312,676			**312,676**	39,900		352,576	19,950	332,626	30.0%
10.1	Certain Automobiles										30.0%
12	Computer Software	73,135			**73,135**			73,135		73,135	100.0%
13.1	Leasehold Improvement # 1										25 years
13.2	Leasehold Improvement # 2										4 years
13.3	Leasehold Improvement # 3										
13.4	Leasehold Improvement # 4										
14	Franchise										6 years
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs										8.0%
43.1	Certain Energy-Efficient Electrical Generating Equipment										30.0%
45	Computers & Systems Software acq'd post Mar 22/04	15,958			**15,958**			15,958		15,958	45.0%
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)										30.0%
47	Distribution System post Feb 22/05	1,508,806			**1,508,806**	2,398,300		3,907,106	1,199,150	2,707,956	8.0%
50	Computer Equipment Post March 18, 2007					27,213		27,213	13,607	13,607	55.0%
	TOTAL	**7,730,800**			**7,730,800**	**2,550,453**		**10,281,253**	**1,275,227**	**9,006,027**	

2008 CCA	UCC 31 Dec/08	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA	UCC 31 Dec/09
225,618	5,426,442	35,000		5,461,442	17,500	5,443,942	4.0%	217,758	5,243,684
							6.0%		
44,457	208,748	110,000		318,748	55,000	263,748	20.0%	52,750	265,998
99,788	252,788	335,000		587,788	167,500	420,288	30.0%	126,086	461,702
							30.0%		
73,135							100.0%		
							8.0%		
							30.0%		
7,181	8,777			8,777		8,777	45.0%	3,950	4,827
							30.0%		
216,636	3,690,470	2,227,800		5,918,270	1,113,900	4,804,370	8.0%	384,350	5,533,920
7,484	19,729	39,040		58,769	19,520	39,249	55.0%	21,587	37,182
674,299	**9,606,954**	**2,746,840**		**12,353,794**	**1,373,420**	**10,980,374**		**806,480**	**11,547,314**

P2 Cumulative Eligible Capital (CEC)

	2008				2009			
CEC Opening Balance [1]				**29,181**				**27,138**
Eligible Capital Property (ECP) Acquisitions								
Other Adjustments								
Subtotal		**x 3/4 =**				**x 3/4 =**		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		**x 1/2 =**				**x 1/2 =**		
Amount transferred on amalgamation or wind-up of subsidiary								
Subtotal before deductions				**29,181**				**27,138**
ECP Dispositions (net)								
Other Adjustments								
Subtotal		**x 3/4 =**				**x 3/4 =**		
Balance before tax deduction				**29,181**				**27,138**
Tax Deduction		*Rate:*	***7.0%***	**2,043**		*Rate:*	***7.0%***	**1,900**
CEC Ending Balance				**27,138**				**25,239**

[1] 2008 amount per ending balance on Schedule 10 of 2007 corporate rax return

P3 Interest Expense

	2008	2009
Deemed Interest Expense (A)	249,129	322,861
3900-Interest Expense	61,437	163,561
Add: Capitalized Interest (USA #6040)		
Add: Capitalized Interest (USA #6042)		
Less: non-debt interest expense (USA #6035)	-16,648	-18,773
Total Interest Projected (B)	**44,789**	**144,788**
Excess Interest Expense		

P4 Loss Carry-Forward (LCF)

	Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/07	2008	2009
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] per Schedule 7-1 of 2007 corporate tax return

P5 Reserve Balances

	Balance 31 Dec/07 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/07	Changes (+ / -) in 2008	Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)	80,000		80,000		80,000		80,000
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL	**80,000**		**80,000**		**80,000**		**80,000**
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts	80,000		80,000		80,000		80,000
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL	**80,000**		**80,000**		**80,000**		**80,000**

[1] per Schedule 13 of 2007 corporate tax return

P6 Taxable Income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		756,491		756,491	378,605	-47,556	644,773
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104	427,256		427,256	622,181	735,424	735,424
Amortization of intangible assets	106						
Recapture of capital cost allowance from Schedule 8	107						
Gain on sale of eligible capital property from Schedule 10	108						
Income or loss for tax purposes- joint ventures or partnerships	109						
Loss in equity of subsidiaries and affiliates	110						
Loss on disposal of assets	111						
Charitable donations	112						
Taxable Capital Gains	113						
Political Donations	114						
Deferred and prepaid expenses	116						
Scientific research expenditures deducted on financial statements	118						
Capitalized interest	119						
Non-deductible club dues and fees	120						
Non-deductible meals and entertainment expense	121						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125	76,272		76,272	80,000	80,000	80,000
Reserves from financial statements- balance at end of year	126	77,241		77,241	80,000	80,000	80,000
Soft costs on construction and renovation of buildings	127						
Book loss on joint ventures or partnerships	205						
Capital items expensed	206						

P6 Taxable Income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		756,491		756,491	378,605	-47,556	644,773
Debt issue expense	208						
Development expenses claimed in current year	212						
Financing fees deducted in books	216						
Gain on settlement of debt	220						
Non-deductible advertising	226						
Non-deductible interest	227						
Non-deductible legal and accounting fees	228						
Recapture of SR&ED expenditures	231						
Share issue expense	235						
Write down of capital property	236						
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237						
Actual Debt Interest					61,437	163,561	163,561
Pensions		3,653		3,653			
Recovery of Regulatory Assets Written Off		372,959		372,959			
Total Additions		**957,381**		**957,381**	**843,618**	**1,058,985**	**1,058,985**

P6 Taxable Income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) ¹		756,491		756,491	378,605	-47,556	644,773
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	369,383		369,383	674,299	806,480	806,480
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405	2,731		2,731	2,043	1,900	1,900
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413	77,241		77,241	80,000	80,000	80,000
Reserves from financial statements - balance at beginning of year	414	76,272		76,272	80,000	80,000	80,000
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Deemed Debt Interest					249,129	322,564	
Revenues from Non-Utility Operations - net					52,895	28,000	28,000
Regulatory Assets Capitalized for Accounting		550,432		550,432			
Total Deductions		**1,076,059**		**1,076,059**	**1,138,366**	**1,318,944**	**996,380**

P6 Taxable Income

	T2 S1 line #	2006 EDR Approved			2008 Projection	2009 @ existing rates	2009 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		756,491		756,491	378,605	-47,556	644,773
NET INCOME (LOSS) FOR TAX PURPOSES		**637,813**		**637,813**	**83,857**	**-307,515**	**707,378**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**637,813**		**637,813**	**83,857**	**-307,515**	**707,378**

P7 Capital Taxes

	2008	2009
OCT (Ontario Capital Tax):		
Rate Base	10,488,693	12,128,985
Less: Exemption	12,500,000	15,000,000
Deemed Taxable Capital		
Tax Rate	0.225%	0.225%
OCT payable		
Federal LCT (Large Corporations Tax):		
Rate Base	10,488,693	12,128,985
Less: Exemption	50,000,000	50,000,000
Deemed Taxable Capital		
Tax Rate		
LCT payable		

P8 Total PILs Expense

	2008 Projection	2009 Projection [1]	2009 Test [1]
Regulatory Taxable Income/(Loss)	83,857	-307,515	707,378
Combined Income Tax Rate	16.50%		22.47%
Total Income Taxes	13,836		158,935
Investment & Miscellaneous Tax Credits			
Income Tax Payable	**13,836**		**158,935**
Large Corporations Tax (LCT)			
Ontario Capital Tax (OCT)			
Grossed-up Income Tax			204,993
Grossed-up LCT			
Total PILs Expense	**13,836**		**204,993**

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

PILs

Details of the PILS calculations are provided following Exhibit 4, Tab 3, Schedule 1 above.

Capital Cost Allowance (CCA)

Details of the CCA Allowance is provided in Exhibit 4, Tab 3, Schedule 1.

Federal T2 tax return

Attached on the pages following this page is a copy of the 2007 T2 tax return

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the T2 Corporation – Income Tax Guide (T4012).

Identification

Business number (BN) 001 86574 9386 RC 0001

Corporation's name

002 Midland Power Utility Corporation

Has the corporation changed its name since the last time you filed your T2 return? 003 [ ] Yes [X] No

If *Yes*, do you have a copy of the articles of amendment? 004 [ ] Yes [ ] No ***(Do Not Submit)***

Address of head office

Has this address changed since the last time you filed your T2 return? 010 [ ] Yes [X] No

(If **yes**, complete lines 011 to 018)

011 16984 Highway 12

012 PO Box 820

City: 015 Midland — Province, territory, or state: 016 ON

Country (other than Canada): 017 — Postal code/Zip code: 018 L4R 4P4

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? 020 Yes [ ] No [X]

(If **yes**, complete lines 021 to 028)

021 c/o 16894 Highway 12

022 PO Box 820

023

City: 025 Midland — Province, territory, or state: 026 ON

Country (other than Canada): 027 — Postal code/Zip code: 028 L4R 4P4

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? 030 [ ] Yes [X] No

(If **yes**, complete lines 031 to 038)

031 16984 Highway 12

032 PO Box 820

City: 035 Midland — Province, territory, or state: 036 ON

Country (other than Canada): 037 — Postal code/Zip code: 038 L4R 4P4

040 Type of corporation at the end of the tax year

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change 043

To which tax year does this return apply?

From 060 2007/01/01 to 061 2007/12/31

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 [ ] Yes [X] No

If **yes**, provide the date control was acquired 065

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1) ? 066 [ ] Yes [ ] No

Is the corporation a professional corporation that is a member of a partnership? 067 [ ] Yes [X] No

Is this the first year of filing after:

Incorporation? 070 [ ] Yes [X] No

Amalgamation? 071 [ ] Yes [X] No

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 [ ] Yes [X] No

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 [ ] Yes [X] No

Is this the final return up to dissolution? 078 [ ] Yes [X] No

Is the corporation a resident of Canada? 080 [X] Yes [ ] No

If **no**, give the country of residence on line 081 and complete and attach Schedule 97. 081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 [ ] Yes [X] No

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085 1 [ ] Exempt under paragraph 149(1)(e) or (l)

2 [ ] Exempt under paragraph 149(1)(j)

3 [ ] Exempt under paragraph 149(1)(t)

4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules - Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	[ ]	9
Is the corporation an associated CCPC?	160	[ ]	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161	[ ]	49
Does the corporation have any non-resident shareholders?	151	[ ]	19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162	[ ]	11
If you answered *Yes* to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163	[ ]	44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	[ ]	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	[ ]	15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166	[ ]	T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167	[ ]	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168	[ ]	22
Did the corporation have any foreign affiliates during the year?	169	[ ]	25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170	[ ]	29
Has the corporation had any non-arm's length transactions with a non-resident?	171	[ ]	T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	[X]	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172	[ ]	-----
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	[X]	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	[ ]	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	[X]	3
Is the corporation claiming any type of losses?	204	[ ]	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	[ ]	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	[X]	6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207	[X]	7
Does the corporation have any property that is eligible for capital cost allowance?	208	[X]	8
Does the corporation have any property that is eligible capital property?	210	[X]	10
Does the corporation have any resource-related deductions?	212	[ ]	12
Is the corporation claiming reserves of any kind?	213	[X]	13
Is the corporation claiming a patronage dividend deduction?	216	[ ]	16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217	[ ]	17
Is the corporation an investment corporation or a mutual fund corporation?	218	[ ]	18
Was the corporation carrying on business in Canada as a non-resident corporation?	220	[ ]	20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221	[ ]	21
Does the corporation have any Canadian manufacturing and processing profits?	227	[ ]	27
Is the corporation claiming an investment tax credit?	231	[ ]	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	[ ]	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	[ ]	-----
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000? .	234	[ ]	-----
Is the corporation claiming a surtax credit?	237	[ ]	37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238	[ ]	38
Is the corporation claiming a Part I tax credit?	242	[ ]	42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243	[ ]	43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244	[ ]	45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249	[ ]	46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250	[ ]	39
Is the corporation claiming a Canadian film or video production tax credit refund?	253	[ ]	T1131
Is the corporation claiming a film or video production services tax credit refund?	254	[ ]	T1177
Is the corporation subject to Part XIII.1 tax?	255	[ ]	92 *

*** We do not print this schedule.**

Attachments - Continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256	☐	T1134-A
Did the corporation have any controlled foreign affiliates?	258	☐	T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259	☐	T1135
Did the corporation transfer or loan property to a non-resident trust?	260	☐	T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261	☐	T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262	☐	T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263	☐	T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264	☐	T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	☒	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266	☐	T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267	☐	T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	☒	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	☐	54

Additional information

Is the corporation inactive?	280	1 Yes ☐	2 No ☒
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes ☐	2 No ☒
What is the corporation's major business activity? (Only complete if **yes** was entered at line 281.)	282		
If the major business activity involves the resale of goods, show whether it is wholesale or retail	283	1 Wholesale ☐	2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.				
	284	hydro distribution	285	100.000 %
	286		287	%
	288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes ☐	2 No ☒
Did the corporation emigrate from Canada during the tax year?	292	1 Yes ☐	2 No ☒

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300	1,720,332	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction *	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal			▶		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				1,720,332	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	1,720,332	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 **400** 1,715,715 A

Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632 on page 7, **minus** 3 times the amount on line 636 on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax **405** 1,720,332 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

$300,000 x (Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year) ____ / 365 = ____ 1

$400,000 x (Number of days in the tax year after 2006 / Number of days in the tax year) 365 / 365 = 400,000 2

Add amounts at lines 1 and 3 400,000 4

Business limit (see notes 1 and 2 below) **410** 400,000 C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 400,000 X (**415** ____ D / 11,250) = ____ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") **425** 400,000 F

Small business deduction

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 16% = 64,000 5

Amount A, B, C, or F whichever is the least 400,000 x (Number of days in the tax year after Dec.31, 2007 / Number of days in the tax year) ____ / 365 x 17% = ____ 6

Total of amounts 5 and 6 - enter on line 9 of page 7 **430** 64,000 G

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] **435** ____ H

Amount H ____ x (Number of days in the tax year in 2005 / Number of days in the tax year) ____ / 365 x 3% = ____ I

Amount H ____ x (Number of days in the tax year in 2006 / Number of days in the tax year) ____ / 365 x 5% = ____ J

Amount H ____ x (Number of days in the tax year in 2007 / Number of days in the tax year) 365 / 365 x 7% = ____ K

Resource deduction – total of amounts I and J **438** ____ L

(enter amount L on line 10 of page 7)

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			1,720,332 A
Amount Z from Part 9 of Schedule 27 ______ x 100 / 7 =		B	
Amount QQ from Part 13 of Schedule 27		C	
Taxable resource income from line 435 on page 4		D	
Amount used to calculate the credit union deduction (from Schedule 17)		E	
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least	400,000	F	
Aggregate investment income from line 440 of page 6	4,617	G	
Total of amounts B, C, D, E, F, and G	404,617	▸	404,617 H
Amount A **minus** amount H (if negative, enter "0")			1,315,715 I

Amount I 1,315,715 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 7% = 92,100 J

Amount I 1,315,715 x (Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year) ______ / 365 x 8.5% = ______ K

General tax reduction for Canadian-controlled private corporations - total of amounts J and K ...... 92,100 L

Enter amount L on line 638 of page 7

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3 (for tax years starting after May 1, 2006, Amount Z on page 3)			M
Amount Z from Part 9 of Schedule 27 ______ x 100 / 7 =		N	
Amount QQ from Part 13 of Schedule 27		O	
Taxable resource income from line 435 on page 4		P	
Amount used to calculate the credit union deduction (from Schedule 17)		Q	
Total of amounts N, O, P, and Q		▸	R
Amount M **minus** amount R (if negative, enter "0")			S

Amount S ______ x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) ______ x 7% = ______ T

Amount S ______ x (Number of days in the tax year after Dec. 31, 2007 and before Jan. 1, 2009 / Number of days in the tax year) ______ x 8.5% = ______ U

General tax reduction - total of amounts T and U V

Enter amount V on line 639 of page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7)	**440** 4,617 X 26 2/3 % =			1,231	A
Foreign non-business income tax credit from line 632 on page 7					
Deduct:					
Foreign investment income (from Schedule 7)	**445** X 9 1/3 % =				
	(if negative, enter "0")				B
Amount A **minus** amount B (if negative, enter "0")				1,231	C
Taxable income from line 360 on page 3		1,720,332			
Deduct:					
Amount on line 400, 405, 410, or 425 on page 4, whichever is the least	400,000				
Foreign non-business income tax credit from line 632 of page 7	x 25/9 =				
Foreign business income tax credit from line 636 of page 7	x 3 =				
	400,000	400,000			
		1,320,332	X 26 2/3% =	352,089	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)		345,169			
Deduct: Corporate surtax from line 600 of page 7		19,268			
Net amount		325,901		325,901	E
Refundable portion of Part I tax -- Amount C, D, or E, whichever is the least			**450**	1,231	F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**				
Deduct: Dividend refund for the previous tax year	**465**				
					G
Add the total of:					
Refundable portion of Part I tax from line 450 above		1,231			
Total Part IV tax payable from Schedule 3					
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**				
		1,231		1,231	H
Refundable dividend tax on hand at the end of the tax year - Amount G **plus** amount H			**485**	1,231	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	300,000	X 1/3	100,000	I
Refundable dividend tax on hand at the end of the tax year from line 485 above			1,231	J
Dividend refund -- Amount I or J, whichever is less (enter this amount on line 784 of page 8)			1,231	

Part I tax

Base amount of Part I tax

taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38%	550	653,726	A

Corporate surtax calculation

Base amount from line A above		653,726	1
Deduct:			
10% of taxable income (line 360 or amount Z, whichever applies) from page 3		172,033	2
Investment corporation deduction from line 620 below			3
Federal logging tax credit from line 640 below			4
Federal qualifying environmental trust tax credit from line 648 below			5
For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:			
28% of taxable income from line 360 on page 3	a		
28% of taxed capital gains	b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)	325,593 c		
Total of lines 2 to 6		172,033	7
Net amount (line 1 **minus** line 7)		481,693	8

Corporate surtax*

Line 8 481,693 x (Number of days in the tax year before January 1, 2008 / Number of days in the tax year) 365 / 365 x 4% = **600** 19,268 B

*The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31	602		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income (if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6		4,617	i
Taxable income from line 360 on page 3	1,720,332		
Deduct:			
Amount on line 400, 405, 410, or 425 of page 4, whichever is the least	400,000		
Net amount	1,320,332 ▸	1,320,332	ii

Refundable tax on CCPC's investment income – 6 2/3% of whichever is less: amount i or ii	604	308	D
Subtotal (**add** lines A, B, C, and D)		673,302	E

Deduct:

Small business deduction from line 430 on page 4		64,000	9	
Federal tax abatement	608	172,033		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
(taxed capital gains **624**)				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
Resource deduction from line 438 on page 4			10	
General tax reduction for CCPCs from amount L on page 5	638	92,100		
General tax reduction from amount V on page 5	639			
Federal logging tax credit from Schedule 21	640			
Federal political contribution tax credit	644			
Federal political contributions **646**				
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		328,133 ▸		328,133 F
Part I tax payable – Line E **minus** line F				345,169 G

Enter amount G on line 700 of page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	345,169
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		345,169

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON

(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec, Ontario and Alberta)	760			
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765			
			▶	
Total tax payable			770	345,169 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784	1,231	
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	377,326	
Total credits	890	378,557	378,557 B

Refund Code **894** 2 Overpayment 33,388

Balance (line A minus line B) (33,388) I

If the result is negative, you have an **overpayment.**
If the result is positive, you have a **balance unpaid.**
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment **898**

Direct Deposit Request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information **910** ______ Branch number

914 ______ Institution number **918** ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** 1 Yes ☐ 2 No ☒ NA ☐

Certification

I, **950** Marley **951** Phil **954** President & CEO ,

Last name First name Position, office or rank

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008/04/28 **956** (705) 526-9361

Date Signature of the authorized signing officer of the corporation Telephone number

Is the contact person the same as the authorized signing officer? If *no*, complete the information below. **957** 1 Yes ☒ 2 No ☐

958 ______ **959** ( ) -

Name Telephone number

Language of correspondence - Langue de correspondance

990 Language of choice/Langue de choix 1 English / Anglais ☒ 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

Schedule 1

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes.

Net income (loss) after taxes and extraordinary items per financial statements			A	244,968
Add:				
Provision for income taxes - current	**101**	587,000		
Amortization of tangible assets	**104**	523,913		
Taxable capital gains - Schedule 6	**113**	4,617		
Tax reserves deducted in prior year - Schedule 13	**125**	80,000		
Reserves from financial statements - balance at the end of the year	**126**	80,000		
Total of fields 201 to 294	**199**	972,015		
Total of fields 101 to 199	**500**	2,247,545	▶	2,247,545
Deduct:				
Gain on disposal of assets per financial statements	**401**	36,734		
Capital cost allowance - Schedule 8	**403**	569,567		
Cumulative eligible capital deduction - Schedule 10	**405**	2,196		
Tax reserves claimed in current year - Schedule 13	**413**	80,000		
Reserves from financial statements - balance at the beginning of the year	**414**	80,000		
Total of fields 300 to 394	**499**	3,684		
Total of fields 401 to 499	**510**	772,181	▶	772,181
Net income (loss) for income tax purposes (enter on line 300 of the T2 return)				1,720,332

Add:		
Other additions:		
603 Net decrease in regulatory assets	**293**	972,015
Total of fields 201 to 294 (Enter this amount at line 199)		972,015
Deduct:		
Other deductions:		
700 Decrease In Employee Future Benefits	**390**	3,684
Total of fields 300 to 394 (Enter this amount at line 499)		3,684

Canada Customs and Revenue Agency Agence des douanes et du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

Schedule 3

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act*.
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- If you need more space, continue on a separate schedule.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide*.

Part 1 - Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

A	B	C	D	E	F
Name of payer corporation 200	Connected? 205	Dividends from foreign source?	Dividends subject to Part IV tax?	Dividends deductible from income under s.112, 113, and 138(6) 240	Non-taxable dividends deductible under section 83 230

Note: If your corporation's taxation year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

Complete if payer corporation is connected and a private or subject corporation					GRIP / LRIP	
G	H	I	J	K		
Business number 210	Taxation year end of the payer corporation in which the dividend was paid 220	Total taxable dividends paid by connected payer corporation 250	Dividend refund of the connected payer corporation 260	Part IV tax before deductions ** 270	Column E deduction type	Indicate eligible dividends
RC		0	0	0		

Total non-taxable dividends deductible under section 83 ______

Total dividends deductible from income under sections 112, 113, and 138(6) ______

** For dividends received from non-connected corporations, Part IV tax = the amount entered in column E x 1/3
For dividends received from connected corporations, do the following calculation: Part IV tax = column E x column J / column I
Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 - Calculation of Part IV tax payable

Part IV tax before deductions (total of column K in Part 1) ______

Deduct:

Part IV.I tax payable on dividends subject to Part IV tax 320 ______

Subtotal ______

Deduct:

Current-year non-capital loss claimed to reduce Part IV tax 330 ______

Non-capital losses from previous years claimed to reduce Part IV tax 335 ______

Current-year farm loss claimed to reduce Part IV tax 340 ______

Farm losses from previous years claimed to reduce Part IV tax 345 ______

Total losses applied against Part IV tax ______ x 1/3 = ______

Part IV tax payable (enter amount on line 712 of the T2 return) 360 0

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

Part 3 - Taxable dividends paid in the taxation year for purposes of a dividend refund

A	B	C	D
Name of connected recipient corporation 400	Business number 410	Taxation year end of connected recipient corporation in which the dividend was received 420	Taxable dividends paid to connected corporations 430
Town Of Midland	RC	2007/12/31	300,000
	RC		
		Total	300,000

Note
If your corporation's taxation year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total taxable dividends paid in the taxation year to other than connected corporations	**450**	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	**460**	300,000

Part 4 - Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

500 ______

Deduct:

Dividends paid out of capital dividend account	**510**		
Capital gains dividends	**520**		
Dividends paid on shares described in subsection 129(1.2)	**530**		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	**540**		
Subtotal			
Total taxable dividends paid in the taxation year for purposes of a dividend refund			0

Canada Revenue Agency / Agence du revenu du Canada

Schedule 6

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

- For use by corporations that have disposed of capital property or claimed an allowable business investment loss, or both, in the tax year.
- Use this schedule to make a designation under paragraph 111(4)(e) of the federal *Income Tax Act*, if the control of the corporation has been acquired by a person or group of persons.

For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the *T2 Corporation - Income Tax Guide*.

Designation under paragraph 111(4)(e) of the *Income Tax Act*

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)?

050 Yes ☐ No ☒ If *Yes*, attach a statement specifying which properties are subject to such a designation.

1 Types of capital property	2 Date of acquisition	3 Proceeds of disposition	4 Adjusted cost base (ACB)	5 Outlays and expenses	6 Gain (or loss) (3 - (4 + 5))

Part 1 – Shares

No. of shares 100	Name of corporation 105	Class of shares 106	Date 110	Proceeds 120	ACB 130	Outlays 140	Gain (or loss) 150
	Enerconnect			9,234			9,234
			Totals	9,234			A 9,234

Part 2 – Real estate - Do not include losses on depreciable property

Municipal address 200	Date 210	Proceeds 220	ACB 230	Outlays 240	Gain (or loss) 250
Address:					
City Province Country Postal code					
Totals					B

Part 3 – Bonds

Face value 300	Maturity date 305	Name of issuer 307	Date 310	Proceeds 320	ACB 330	Outlays 340	Gain (or loss) 350
			Totals				C

Part 4 – Other properties - Do not include losses on depreciable property

Description 400	Date 410	Proceeds 420	ACB 430	Outlays 440	Gain (or loss) 450
Totals					D

SUMMARY OF DISPOSITIONS OF CAPITAL PROPERTY

Part 5 – Personal-use property (Do not include listed personal property)

Description 500	Date 510	Proceeds 520	ACB 530	Outlays 540	Gain only 550
	Totals				E

Note: Losses are not deductible.

Part 6 – Listed personal property

Description 600	Date 610	Proceeds 620	ACB 630	Outlays 640	Gain (or loss) 650
	Totals				
Subtract: Unapplied listed personal property losses from other years				655	
Amount from line 655 is from line 530 in Part 5 of Schedule 4.				Net gains (or losses)	F

Note: Net listed personal property losses may only be applied against listed personal property gains.

Part 7 – Determining allowable business investment losses
Property qualifying for and resulting in an allowable business investment loss

Name of small business corporation 900	Shares or debt 905	Date 910	Proceeds 920	ACB 930	Outlays 940	Loss 950
	N/A					
		Totals				G

Note: Properties listed in part 7 should not be included in any other parts of Schedule 6

Allowable business investment losses Amount G X 50.0000 H

Enter amount H on line 406 of Schedule 1.

Part 8 – Determining capital gains or losses

Total of amounts A to F (do not include F, if the amount is a loss)		I	9,234
Add:			
Capital gains dividends received in the year	875	J	
Capital gains reserve opening balance (from Schedule 13)	880	K	
Subtotal (add amounts I, J, and K)		L	9,234
Deduct: Capital gains reserve closing balance (from Schedule 13)	885	M	
Capital gains or losses (amount L minus amount M)	890		9,234

Part 9 – Determining taxable capital gains and total capital losses

Capital gains or losses (amount from line 890 above) N 9,234

Deduct the following gains that are included in the amount N:

Gain on donation of a share, debt obligation, or right listed on a prescribed stock exchange and other amounts under paragraph 38(a.1) of the *Income Tax Act*

realized prior to May 2, 2006 ____ x 1/2 = O

realized after May 1, 2006 P

Subtotal: O plus P 895

Gain on donation of ecologically sensitive land

realized prior to May 2, 2006 ____ x 1/2 = Q

realized after May 1, 2006 R

Subtotal: Q plus R 896

Total: 895 plus 896 S

Amount N minus amount S T 9,234

Total capital losses: If amount T is a loss, enter it on line 210 of Schedule 4.

Taxable capital gains: If amount T is a gain, enter it on this line and multiply

9,234 X 50.0000 = U 4,617

Enter amount U on line 113 of Schedule 1.

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CALCULATION OF AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Schedule 7

- This schedule is for the use of Canadian-controlled private corporations to calculate:
  - aggregate investment income and foreign investment income for the purpose of determining the refundable portion of Part I tax, as defined in subsection 129(4) of the *Income Tax Act*;
  - specified partnership income for members of one or more partnership(s); and
  - income from an active business carried on in Canada for the small business deduction.
- For more information, see the sections called "Small Business Deduction" and "Refundable Portion of Part I Tax" in the *T2 Corporation - Income Tax Guide*.

Details of property income (losses)

	Foreign	Aggregate
Taxable dividends deductible from Schedule 3		
Related expenses	-	-
Taxable dividends deductible after deducting related expenses	=	=
Net rental income (loss) before CCA:		
Subtotal		
Capital cost allowance	-	-
Net rental income (loss)	=	=
Exempt income	+	+
Amounts received from NISA Fund No. 2	+	+
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) of the *Income Tax Act*	+	+
Interest and other property income:	+	+
Total income (losses) from property	=	=

Part 1 - Aggregate investment income calculation

The aggregate investment income is the aggregate **world** source income.

The eligible portion of taxable capital gains included in income for the year	002	4,617	A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	012		B
Net capital losses of other years claimed on line 332 on the T2 return	022		C
Total of amounts B and C			D
Amount A **minus** amount D (if negative, enter "0")		4,617	E
Total income from property (include income from a specified investment business carried on in Canada other than income from a source outside Canada)	032		F
Exempt income	042		G
Amounts received from NISA Fund No. 2 that were included in computing the corporation's income for the year	052		H
Taxable dividends deductible (total of Column E on Schedule 3)	062		I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	072		J
Total of amounts G, H, I, and J			K
Amount F **minus** amount K			L
Amount E **plus** amount L		4,617	M
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)	082		N
Amount M **minus** amount N (if negative, enter "0")	092	4,617	O

Enter amount **O** on line 440 of the T2 return.

AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Part 2 - Foreign investment income calculation

The foreign investment income is all income from only sources outside of Canada.

The eligible portion of taxable capital gains included in income for the year	001		A
Eligible portion of allowable capital losses for the year (including allowable business investment losses)	009		B
Amount A **minus** amount B (if negative, enter "0")		0	C
Total income from property from a source **outside Canada**	019		D
Exempt income	029		E
Taxable dividends deductible (total of Column E on Schedule 3)	049		F
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a)	059		G
Total of amounts E, F, and G			H
Amount D **minus** amount H			I
Amount C **plus** amount I			J
Total losses from property from a source **outside Canada**	069		K
Amount J **minus** amount K (if negative, enter "0")	079	0	L

Enter amount **L** on line 445 of the T2 return

AGGREGATE INVESTMENT INCOME AND ACTIVE BUSINESS INCOME

Part 3 - Specified partnership income

A			B	C
Partnership name 200	Start of fiscal period	End of fiscal period	Total income (loss) from active business 300	Corporation's share of amount in column B 310

D	E	F	G	H	I
Adjustments [add reserves deducted under ss.34.2(5) and deduct expenses] 315	Corporation's income (loss) of the partnership (column C **plus** column D) 320	# of days in the partnership's fiscal period 325	Prorated business limit (column C ÷ column B) x [business limit* x (column F ÷ 365)]** 330	Column E **minus** column G (if negative, enter "0")	Lesser of columns E and G (if negative, enter "0") 340
Total	350		Total	385	360

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) - enter as a positive amount	370			
Specified partnership loss of the corporation for the year - enter as a positive amount (total of all negative amounts in column E)	380			
Total of lines 370 and 380			▶	J
Amount at line 385 or line J, whichever is less			390	
Specified partnership income (line 360 **plus** line 390)			400	

* Use one of the following business limits to calculate column G, whichever applies:
- $250,000 if the corporation's tax year ends in 2004;
- $300,000 if the corporation's tax year ends in 2005 or 2006; or
- $400,000 if the corporation's tax year ends after 2006.

** When a partnership carries on more than one business, one of which generates income and another of which realizes a loss, the loss is not netted against the partnership's income.

Part 4 - Determination of partnership income

Corporation's share of partnership income from active businesses carried on in Canada after deducting related expenses - from line 350 above (if the net amount is negative, enter "0" on line O)			K
Add: Specified partnership loss (from line 380 above)			L
Subtotal			M
Deduct: Specified partnership income (from line 400 above)			N
Partnership income (enter on line S below)	450		O

Part 5 - Income from active business carried on in Canada

Net income for income tax purposes from line 300 of the T2 return			1,720,332	P
Deduct: Foreign business income after deducting related expenses *	500			
Taxable capital gains **minus** allowable capital loss - amount A **minus** amount B* (page 1) **		4,617		
Net property income = amount F **minus** amounts G, H, and N * (page 1)			Q	
Personal services business income after deducting related expenses *	520			
		4,617	4,617	
		Net amount	1,715,715	R
Deduct: Partnership income (line 450 above)				S
Income from active business carried on in Canada (enter on line 400 of the T2 return - if negative, enter "0")			1,715,715	T

* If negative, enter amount in brackets, and **add** instead of **subtracting**.
** This amount may only be negative to the extent of any allowable business investment losses.

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CAPITAL COST ALLOWANCE

Schedule 8

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class **200**	2 UCC at start of year **201**	3 Cost of additions in the year **203**	4 Net adjustments **205**	5 Proceeds of dispositions in the year **207**	7 Adjustment for additions (1/2 x (col 3 - 5)) **211**	8 Base amount for CCA	9 Rate % **212**	10 Recapture of CCA **213**	11 Terminal loss **215**	12 CCA for the year (col 8 x 9 or a lower amount) **217**	13 UCC at the end of the year **220**
1	5,825,396	37,224			18,612	5,844,008	4			233,760	5,628,860
8	167,216	63,991			31,996	199,211	20			39,842	191,365
10	295,517	151,987		27,500	62,244	357,760	30			107,328	312,676
12	20,821	146,270			73,135	93,956	100			93,956	73,135
45	8,741	14,388			7,194	15,935	45			7,171	15,958
47	591,435	1,004,881			502,441	1,093,875	8			87,510	1,508,806
Totals	6,909,126	1,418,741		27,500	695,622	7,604,745				569,567	7,730,800

S8Supp

Reconciliation of NBV and UCC

NBV of capital assets, beginning of year		5,735,722	
Less: Land	-	365,298	
NBV of depreciable capital assets, beginning of year		5,370,424	5,370,424
UCC beginning of year		6,909,126	
Less: Opening Class 14 balance	-		
Adjusted UCC		6,909,126	- 6,909,126
Timing difference, beginning of year			(1,538,702) A
CCA and amortization			
CCA claimed (except class 14)	+	569,567	
Terminal loss	+		
Recapture	-		
Amortization per financial statements	-	523,913	
Class 10.1			
Difference on purchase (cost ______ less ceiling ______)	+		
Beginning UCC less CCA in year of disposal	+		
NBV of class 10.1 asset prior to sale (proceeds, if financial statement gain)	-		
Gains and losses			
Gain on disposal of capital assets per financial statements	+	27,500	
Capital loss portion of total loss	+		
Loss on disposal of capital assets per financial statements	-		
Capital gain portion of total gain	-		
Other			
Operating leases capitalized for financial statement purposes	+		
Deductible items capitalized for financial statement purposes	+		
Section 85 difference	+		
Pre-valuation day depreciation	+		
	+		
Timing difference, current year		73,154	+ 73,154 B
Timing difference, end of year (A + B)			(1,465,548) C
Proof			
NBV of capital assets, end of year		6,630,550	
Less: Land	-	365,298	
NBV of depreciable capital assets, end of year		6,265,252	6,265,252
UCC end of year		7,730,800	
Less: Ending Class 14 balance	-		
Adjusted UCC		7,730,800	- 7,730,800
Timing difference as at 2007/12/31 (amount D should equal amount C)			(1,465,548) D

Notes

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CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Schedule 10

Part 1 - Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	31,377	A
Add: Cost of eligible capital property acquired during the taxation year	222				
Other adjustments	226				
Subtotal (line 222 plus line 226)		x 3/4 =			B
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1/2 =			C
amount B minus amount C (if negative, enter "0")					D
Amount transferred on amalgamation or wind-up of subsidiary			224		E
Subtotal (add amounts A, D, and E)			230	31,377	F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242		G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244		H		
Other adjustments	246		I		
(add amounts G, H, and I)		x 3/4 =	248		J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)				31,377	K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249		
amount K	31,377				
less amount from line 249					
Current year deduction	31,377	x 7% =	250	2,196 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			2,196	2,196	L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	29,181	M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80 (7)		401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")				5	
Total of lines 1, 2, and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409			9	
Line 6 minus line 9 (if negative, enter "0")					O
Line N minus line O (if negative, enter "0")					P
Line 5		x 1/2 =			Q
Line P minus line Q (if negative, enter "0")					R
Amount R		x	66.6667		S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			410		

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CONTINUITY OF RESERVES

Schedule 13

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 - Capital gains reserves

Description of property 001	Balance at the beginning of the year 002	Transfer on wind-up or amalgamation 003	Balance at the end of the year 004
Totals	008	009	010

The total capital gains reserve at the beginning of the taxation year plus the total transfer on wind-up or amalgamation should be entered on line 880, and the total capital gains reserve at the end of the taxation year should be entered on line 885 of Schedule 6.

Part 2 - Other reserves not deducted for accounting purposes

Description of property	Balance at the beginning of the year	Transfer on wind-up or amalgamation	Balance at the end of the year
Reserve for doubtful debt	110 80,000	115	120 80,000
Reserve for undelivered goods and services not rendered	130	135	140
Reserve for prepaid rent	150	155	160
Reserve for December 31, 1995 income	170	175	180
Reserve for returnable containers	190	195	200
Reserve for unpaid amounts	210	215	220
Other tax reserves	230	235	240
Totals	270 80,000	275	280 80,000

The amount from line 270 plus the amount from line 275 should be included on line 125 of Schedule 1 as an addition.
The amount from line 280 should be included on line 413 of Schedule 1 as a deduction.

Part 3 - Accounting reserves not deductible for tax purposes

Description of property	Balance at the beginning of the year	Balance at the end of the year
Reserve for doubtful debt	80,000	80,000
Totals	A 80,000	B 80,000

Enter amount A on line 414 of Schedule 1 as a deduction.
Enter amount B on line 126 of Schedule 1 as an addition.

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SHAREHOLDER INFORMATION

Schedule 50

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual or trust) **100**	Business Number (If a corporation is not registered, enter "NR") * **200**	Social Insurance Number * **300**	Trust Number (If a trust number is not available, enter "NA") * **350**	Percentage common shares **400**	Percentage preferred shares **500**
Town of Midland	NR			91.000	
	RC				

* For a taxation year commencing before January 1, 2004, if the shareholder is a trust, enter NR at field 200 or NA at field 300. Do not enter a trust number in field 350.

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GENERAL RATE INCOME POOL (GRIP) CALCULATION

Schedule 53

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

	Line	Amount	Line	Amount	Line	Amount	
GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")					50	0	A
GRIP at the end of the previous tax year					100	772,068	B
Taxable income for the year (DICs enter "0")*			110	1,720,332			C
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120	0					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130	400,000					
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140	4,617					
Subtotal (**add** lines 120, 130, and 140)		404,617 ▶		404,617			D
Income taxable at the general corporate rate (line C **minus** line D)			150	1,315,715			
After-tax income (line 150 **multiplied by** 68%)					190	894,686	E
Eligible dividends received during the year by the corporation from:							
Amounts entered on S3				0			
Any other amounts to include				+ 0			
Eligible dividends received in the tax year			200	0			
Dividends deductible under section 113 received in the tax year			210	0			
Subtotal (**add** lines 200 and 210)				0 ▶		0	F
GRIP addition:							
Becoming a CCPC (line PP from Part 4)			220	0			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)			230	0			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)			240	0			
Subtotal (**add** lines 220, 230, and 240)				0 ▶	290	0	G
Subtotal (**add** lines A or B (as applicable), E, F, and G)						1,666,754	H
Eligible dividends paid in the previous tax year			300	0			
Excessive eligible dividend designations made in the previous tax year			310	0			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.							
Subtotal (line 300 **minus** line 310)				0 ▶		0	I
GRIP before adjustment for specified future tax consequences (line H minus line I) (amount can be negative)					490	1,666,754	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)					560	0	
GRIP at the end of the tax year (line 490 minus line 560)					590	1,666,754	

Enter this amount on line 160 on Schedule 55.

* **Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year

Taxable income before specified future tax consequences from the current tax year.			0	J1		
Enter the following amounts before specified future tax consequences from the current tax year:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0	K1				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0	L1				
Aggregate investment income (line 440 of the T2 return)	0	M1				
Subtotal (**add** lines K1, L1, and M1)	0 ▶		0	O1		
Subtotal (line J1 **minus** line O1) (if negative, enter "0")			0 ▶		0	P1
Taxable income after specified future tax consequences			0	Q1		
Enter the following amounts after specified future tax consequences:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0	R1				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0	S1				
Aggregate investment income (line 440 of the T2 return)	0	T1				
Subtotal (**add** lines R1,S1, and T1)	0 ▶		0	V1		
Subtotal (line Q1 **minus** line V1) (if negative, enter "0")			0 ▶		0	W1
Subtotal (line P1 **minus** line W1) (if negative, enter "0")					0	X1
GRIP adjustment for specified future tax consequences to first previous tax year(X1 multiplied by 68%) **500**					0	

Second previous tax year

Taxable income before specified future tax consequences from the current tax year.			0	J2		
Enter the following amounts before specified future tax consequences from the current tax year:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0	K2				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0	L2				
Aggregate investment income (line 440 of the T2 return)	0	M2				
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0	N2				
Subtotal (**add** lines K2, L2, and M2)	0 ▶		0	O2		
Subtotal (line J2 **minus** line O2) (if negative, enter "0")			0 ▶		0	P2
Taxable income after specified future tax consequences			0	Q2		
Enter the following amounts after specified future tax consequences:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0	R2				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0	S2				
Aggregate investment income (line 440 of the T2 return)	0	T2				
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0	U2				
Subtotal (**add** lines R2,S2, and T2)	0 ▶		0	V2		
Subtotal (line Q2 **minus** line V2) (if negative, enter "0")			0 ▶		0	W2
Subtotal (line P2 **minus** line W2) (if negative, enter "0")					0	X2
GRIP adjustment for specified future tax consequences to first previous tax year(X2 multiplied by 68%) **520**					0	

GENERAL RATE INCOME POOL (GRIP) CALCULATION

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year

Taxable income before specified future tax consequences from the current tax year.		0 J3		
Enter the following amounts before specified future tax consequences from the current tax year:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 K3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 L3			
Aggregate investment income (line 440 of the T2 return)	0 M3			
Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7**	0 N3			
Subtotal (**add** lines K3, L3, and M3)	0 ▸	0 O3		
Subtotal (line J3 **minus** line O3) (if negative, enter "0")		0 ▸	0 P3	
Taxable income after specified future tax consequences		0 Q3		
Enter the following amounts after specified future tax consequences:				
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	0 R3			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	0 S3			
Aggregate investment income (line 440 of the T2 return)	0 T3			
Accelerated tax reduction (line 637 of T2 return)* **multiplied** by 100/7	0 U3			
Subtotal (**add** lines R3,S3,T3 and U3)	0 ▸	0 V3		
Subtotal (line Q3 **minus** line V3) (if negative, enter "0")		0 ▸	0 W3	
Subtotal (line P3 **minus** line W3) (if negative, enter "0")			0 X3	
GRIP adjustment for specified future tax consequences to first previous tax year(X3 **multiplied** by 68%) **540**				0
Total GRIP adjustment for specified future tax consequences to previous tax years: (**add** lines 500, 520, and 540) (if negative, enter "0")				0 Y

Enter amount Y on line 560 on page 1.

* **Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year		0 AA
Eligible dividends paid by the corporation in its last tax year	0 BB	
Excessive eligible dividend designations made by the corporation in its last tax year	0 CC	
Subtotal (line BB **minus** line CC)	0 ▸	0 DD
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year) (line AA **minus** line DD)		0 EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			0 FF
The corporation's money on hand immediately before the end of its previous/last tax year			0 GG
Unused and unexpired losses at the end of the corporation's previous tax year			
Non-capital losses	0		
Net capital losses	0		
Farm losses:	0		
Restricted farm losses	0		
Limited partnership losses	0		
Subtotal	0 ▸	0 HH	
Subtotal (**add** lines FF, GG, and HH)			0 II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		0 JJ	
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		0 KK	
All the corporation's reserves deducted in its previous/last tax year		0 LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		0 MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		0 NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		0 ▸	0 OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			0 PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 on page 1 for a corporation becoming a CCPC;
- line 230 on page 1 for post-amalgamation; or
- line 240 on page 1 for post-wind-up.

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Part 5 – GRIP addition for 2006

Use this part to calculate the GRIP balance for a corporation that was a CCPC, or would have been but for an election under subsection 89(11), throughout its tax year that includes January 1, 2006.

	Tax years ending in				
	2001	2002	2003	2004	2005
1. Taxable income for the year*	0	0	0	0	0
2. Income for manufacturing and processing profits deduction* (lesser of amount V and Y in Part 9 of Schedule 27)	0	0	0	0	0
3. Income for manufacturing and processing profits deduction—electrical energy, steam* (amount QQ in Part 13 of Schedule 27)	0	0	0	0	0
4. Taxable resource income* (line 435 of the T2 return)	0	0	0	0	0
5. Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	0	0	0	0	0
6. Income for the small business deduction* (amount on line 400, 405, 410, and 425 of the T2 return, whichever is less)	0	0	0	0	0
7. Aggregate investment income* (line 440 of the T2 return)	0	0	0	0	0
8. Income for the accelerated tax reduction* (line 637 of the T2 return multiplied by 100/7)	0	0	0	0	0
9. Subtotal (**add** rows 2 through 8)	0	0	0	0	0
10. Full rate taxable income before specified future tax consequences (row 1 minus row 9) (if negative, enter "0")	0	0	0	0	0
11. **Multiply** row 10 by 63%	0	0	0	0	0
12. Dividends deductible under subsection 112(1) received from connected corporations, that are reasonably considered, to have been paid out of full rate taxable income in respect of the payer corporation	**941** 0	**942** 0	**943** 0	**944** 0	**945** 0
13. **Subtotal** (**add** row 11 and row 12)	0	0	0	0	0
14. Total taxable dividends paid by the corporation (greater of amounts on line 460 and line 500 on Schedule 3)	0	0	0	0	0
15. GRIP addition (row 13 **minus** row 14)(show negative amounts in brackets)	**951** 0	**952** 0	**953** 0	**954** 0	**955** 0

GRIP addition for 2006 (**add** lines 951, 952, 953, 954, and 955) 0 QQ

Enter the greater of amount QQ or "0" on line 050 on page 1.

* **Note:** For rows 1 to 8, all income amounts are before considering the specified future tax consequences for that tax year.

Canada Revenue Agency Agence du revenu du Canada

Schedule 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 - Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends from Schedule 3		300,000			
Taxable dividends not entered on Schedule 3		0			
Total taxable dividends paid in the tax year	100	300,000			
Total eligible dividends paid in the tax year			150	0	
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	1,666,754	
Excessive eligible dividend designation (line 150 **minus** line 160)				0	A
Part III.1 tax on excessive eligible dividend designations - CCPC or DIC (line A **multiplied** by 20%)			190	0	

Part 2 - Other corporations

Taxable dividends from Schedule 3		0			
Taxable dividends not entered on Schedule 3		0			
Total taxable dividends paid in the tax year	200	0			
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)				0	B
Part III.1 tax on excessive eligible dividend designations - Other corporations (line B **multiplied** by 20%)			290	0	

TaxPaid

Tax instalments paid

Jurisdiction	Description	Date	Amount
Federal		2007/12/31	360,526
Ontario		2007/12/31	175,441
Ontario		2008/03/11	100,000
Federal		2008/03/11	16,800
Federal			
		Total	652,767

* Enter Québec instalments paid on form CO-1027.VE

Summary by jurisdiction

Federal	377,326	Manitoba	
British Columbia		Ontario	275,441
Alberta			
Saskatchewan			

Tax Summary

Corporation name Midland Power Utility Corporation

Tax year ending 2007/12/31

Taxable income

Net income for tax purposes		1,720,332
Charitable donations and gifts	-	
Taxable dividends	-	
Losses of prior years	-	
Other adjustments	±	
Taxable income	=	1,720,332

Part I tax

38% of taxable income			653,726
Surtax		+	19,268
Refundable tax on CCPC investment income		+	308
Active business income	1,715,715		
Small business deduction		-	64,000
Federal tax abatement		-	172,033
Manufacturing and processing deduction		-	
Additional deduction - credit unions		-	
Foreign tax credits		-	
Resource deduction		-	
Political contribution tax credit		-	
Investment tax credit		-	
Other deductions and credits		-	92,100
Part I tax		=	345,169

Tax payable

Part I tax			345,169
Part I.3 tax (large corporations tax)		+	
Taxable dividends received			
Part IV tax		+	
Other federal tax payable		+	
Subtotal		=	345,169
Provincial and territorial tax (except QC,ON,AB)		+	
Provincial tax on large corporations (NB,NS)		+	
Tax payable		+	345,169
Tax instalments paid		-	377,326
Investment tax credit refund		-	
Taxable dividends paid	300,000		
Dividend refund		-	1,231
Other refundable credits		-	
Balance owing (refund) on federal return		=	(33,388)
Provincial income tax (ON,AB,QC)			240,846
Capital and other provincial taxes		+	
Tax instalments and credits		-	275,441
Other provincial taxes		=	(34,595)
Total balance owing (refund)			(67,983)

Provincial tax

	% Provincial allocation	Taxable income	Income tax	Capital and other provincial taxes	Tax instalments and credits	Net provincial tax
Newfoundland						
Prince Edward Island						
Nova Scotia						
New Brunswick						
Manitoba						
Saskatchewan						
British Columbia						
Yukon Territory						
Northwest Territories						
Nunavut						
Schedule 5 provincial tax payable						
Ontario	100.0000	1,720,332	240,846		275,441	(34,595)
Alberta						
Québec						
Totals			240,846		275,441	(34,595)

Loss continuity

	Current year carry back	Carryforward end of year
Capital		
Non-capital		
Farm		
Restricted farm		
Limited partnership		
Listed personal property		

Other carryforwards

Capital dividend account	4,617
Refundable dividend tax on hand (net of dividend refund)	
Unused Part 1.3 tax credit	
Unused surtax credits	35,344
Foreign business tax credits	
Donations and gifts	
Investment tax credits	
Ontario CMT losses	
Ontario CMT credit	

5 Year Tax Summary

Years Ending:	2007/12/31	2006/12/31	2005/12/31	2004/12/31	2003/12/31
Taxable income					
Net Income for tax purposes	1,720,332	1,645,221	436,837	637,813	122,005
Charitable donations and gifts	-	-	-	-	-
Taxable dividends	-	-	-	-	-
Losses of other years	-	- 209,827	- 436,837	- 637,813	- 122,005
Other adjustments	±	±	±	±	±
Taxable income	= 1,720,332	= 1,435,394	=	=	=
Active business income	1,715,715	1,645,221	436,837	637,813	122,005
Part I tax					
38% of taxable income	653,726	545,450			
Surtax	+ 19,268	+ 16,076	+	+	+
Refundable tax on CCPC investment income	+ 308	+	+	+	+
Small business deduction	- 64,000	- 48,000	-	-	-
Federal tax abatement	- 172,033	- 143,539	-	-	-
Manufacturing and processing deduction	-	-	-	-	-
Additional deduction - credit unions	-	-	-	-	-
Foreign tax credits	-	-	-	-	-
Resource deduction	-	-	-	-	-
Political contribution tax credit	-	-	-	-	-
Investment tax credit	-	-	-	-	-
Other deductions and credits	- 92,100	- 79,478	-	-	-
Part I tax	= 345,169	= 290,509	=	=	=
Tax payable					
Part I tax	345,169	290,509			
Part I.3 tax	+	+	+	+	+ 61
Part IV tax	+	+	+	+	+
Other federal tax payable	+	+	+	+	+
Subtotal	= 345,169	= 290,509	=	=	= 61
Provincial and territorial tax (except QC,ON,AB)	+	+	+	+	+
Provincial tax on large corporations (NB,NS)	+	+	+	+	+
Tax payable	= 345,169	= 290,509	=	=	= 61
Tax instalments made	- 377,326	- 290,509	-	-	- 61
Investment tax credit refund	-	-	-	-	-
Dividend refund	- 1,231	-	-	-	-
Other refundable credits	-	-	-	-	-
Balance owing (refund)	= (33,388)	=	=	=	=
Provincial income tax (ON,AB,QC)	240,846	140,535	(7,714)	27,324	
Capital and other provincial taxes	+	+ 1,906	+ 7,714	+ 16,738	+ 14,468
Tax instalments and credits	- 275,441	- 243,763	-	- 44,075	- 18,721
Other provincial taxes	= (34,595)	= (101,322)	=	= (13)	= (4,253)
Total taxes owing (refund)	(67,983)	(101,322)		(13)	(4,253)

Ontario

Ministry of Revenue

Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Midland Power Utility Corporation	1800345	2007/12/31

Part 1: Calculation of CMT Base

Banks - Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.
Life Insurance corporations - Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net income/(loss) (unconsolidated, determined in accordance with GAAP)			2100 ±	244,968
Subtract (to the extent reflected in net income/loss):				
Provision for recovery of income taxes / benefit of current income taxes	2101 +			
Provision for deferred income taxes (credits) / benefit of future income taxes	2102 +			
Equity income from corporations	2103 +			
Share of partnership(s)/joint venture(s) income	2104 +			
Dividends received/receivable deductible under fed.s.112	2105 +			
Dividends received/receivable deductible under fed.s.113	2106 +			
Dividends received/receivable deductible under fed.s.83(2)	2107 +			
Dividends received/receivable deductible under fed.s.138(6)	2108 +			
Federal Part VI.1 tax on dividends declared and paid, under fed.s.191.1(1) ____ x 3 =	2109 +			
Subtotal	=		▸ 2110 -	
Add (to extent reflected in net income/loss):				
Provision for current taxes / cost of current income taxes	2111 +	587,000		
Provision for deferred income taxes (debits) / cost of future income taxes	2112 +			
Equity losses from corporations	2113 +			
Share of partnership(s)/joint venture(s) losses	2114 +			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	2115 +			
Subtotal	=	587,000	▸ 2116 +	587,000

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	2117 +		or 2118 -			
** Fed.s.85.1	2119 +		or 2120 -			
** Fed.s.97	2121 +		or 2122 -			
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	2123 +		or 2124 -			
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	2125 +		or 2126 -			
** Amounts relating to s.57.10 election/regulations for replacement re fed.s.13(4), 14(6) and 44 for current/prior years	2127 +		or 2128 -			
Interest allowable under ss. 20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income			2150 -			
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)			2155 -			
Subtotal (Additions)	=	▸			2129 +	
Subtotal (Subtractions)			=		▸ 2130 -	
** Other adjustments					2131 ±	
Subtotal ± 2100 - 2110 + 2116 + 2129 - 2130 ± 2131					2132 =	831,968
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss					2133 ±	
Adjusted net income (loss) (if loss, transfer to **2202** in ***Part 2: Continuity of CMT Losses Carried Forward.***)					2134 =	831,968
Deduct: * CMT losses: pre-1994 Loss			From 2210 +			
* CMT losses: other eligible losses			2211 +			
			=		▸ 2135 -	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this tax return.*

CMT Base **2136** = 831,968

Transfer to CMT Base on page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)

Part 2: Continuity of CMT Losses Carried Forward

CMT loss continuity by year

Year of origin	Beginning balance	Transfers on amalgamation	Transfers on wind-up	Adjustments	Current year loss	Applied	Ending balance
							Expired
2002/12/31							
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
Totals							

Balance at Beginning of year Notes (1), (2) 2201 +

Add: Current year's losses 2202 +

Losses from predecessor corporations on amalgamation **Note (3)** 2203 +

Losses from predecessor corporations on wind-up **Note (3)** 2204 +

Amalgamation (1) **2205** ☐ Yes Wind-up (1) **2206** ☐ Yes

Subtotal = ▶ 2207 +

Adjustments (attach schedule) 2208 ±

CMT losses available 2201 + 2207 ± 2208 2209 =

Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income 2210 +

Other eligible losses utilized during the year to reduce adjusted net income **Note (4)** 2211 +

Losses expired during the year 2212 +

Subtotal = ▶ 2213 -

Balances at End of Year Note (5) 2209 - 2213 2214 =

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income **2134** and CMT losses available **2209**.

(5) Amount in **2214** must equal sum of **2270 + 2290**.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

Year of Origin (oldest year first)	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	2260	2280
2241	2261	2281
2242	2262	2282
2243	2263	2283
2244 2002/12/31	2264	2284
2245 2003/12/31	2265	2285
2246 2004/12/31	2266	2286
2247 2005/12/31	2267	2287
2248 2006/12/31	2268	2288
2249 2007/12/31	2269	2289
Totals	2270	2290

The sum of amounts 2270 + 2290 must equal amount in 2214.

Corporate Minimum Tax (CMT)

Part 4: Continuity of CMT Credit Carryovers

CMT credit continuity by year

Year of origin	Beginning balance	Transfers on amalgamation or wind-up	Adjustments	Current year credit	Applied	Expired	Ending balance
2003/12/31							
2004/12/31							
2005/12/31							
2006/12/31							
2007/12/31							
Totals							

Balance at Beginning of year Note (1) 2301 +

Add: Current year's CMT Credit (**280** on page 8 of the CT23 or **347** on page 6 of the CT8. If negative, enter NIL) From **280 or 347** +

Gross Special Additional Tax **Note (2) 312** on page 5 of CT8.
(Life Insurance corporations only. Others enter NIL.)From **312** +

Subtract Income Tax
(**190** on page 6 of the CT23 or page 4 of the CT8) From **190** -

Subtotal (If negative, enter NIL) = ▶ 2305 -

Current year's CMT credit (If negative, enter NIL) **280** or **347 – 2305** = ▶ **2310** +

CMT Credit Carryovers from predecessor corporations **Note (3)** **2325** ±

Amalgamation (1) **2315** ☐ Yes Wind-up (1) **2320** ☐ Yes

Subtotal 2301 + 2310 + 2325 **2330** +

Adjustments *(Attach schedule)* **2332** ±

CMT Credit Carryover available 2330 ± 2332 **2333** =

Transfer to Page 8 of the CT23 *or page 6 of the CT8*

Subtract: CMT credit utilized during the year to reduce income tax
(**310** on page 8 of the CT23 or **351** on page 6 of the CT8.) + From **310 or 351**
CMT Credit expired during the year **2334** +

Subtotal = ▶ **2335** -

Balance at End of Year Note (4) 2333 - 2335 **2336** =

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))
(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).
(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))
(4) Amount in **2336** must equal the sum of **2370 + 2390**.

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

Year of Origin (oldest year first)	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	2360	2380
2341	2361	2381
2342	2362	2382
2343	2363	2383
2344	2364	2384
2345 2003/12/31	2365	2385
2346 2004/12/31	2366	2386
2347 2005/12/31	2367	2387
2348 2006/12/31	2368	2388
2349 2007/12/31	2369	2389
Totals	2370	2390

The sum of amounts 2370 + 2390 must equal amount in 2336.

Ontario CT23 tax return

Attached on the pages following this page is a copy of the 2007 CT23 tax return

Ontario

Ministry of Finance
Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007

CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act - Ministry of Finance (MOF)
Corporations Information Act - Ministry of Government Services (MGS)

This form is a combination of the Ministry of Revenue (MOR) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return.** Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☒ Yes ☐ No

Ministry Use

Corporation's Legal Name *(including punctuation)*
Midland Power Utility Corporation

Ontario Corporations Tax Account No. (MOF)
1800345

This Return covers the Taxation Year
Start 2007/01/01
End 2007/12/31

Mailing address
16894 Highway 12
PO Box 820

City	Province	Country	Postal code
Midland	ON	CA	L4R 4P4

Has the mailing address changed since last filed CT23 Return? ☐ Yes | Date of Change | year month day

Date of Incorporation or Amalgamation
2002/05/01

Registered/Head Office Address
16984 Highway 12
PO Box 820

City	Province	Country	Postal code
Midland	ON		L4R 4P4

Ontario Corporation No. (MGS) 1519158

Location of Books and Records
16984 Highway 12
PO Box 820

City	Province	Country	Postal code
Midland	ON		L4R 4P4

Canada Revenue Agency Business No.
865749386RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
Phil Marley	(705) 526-9361	( ) -

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario (*Extra-Provincial Corporations only*) (MGS)

City	Province	Country	Postal code

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced
Ceased
☒ *Not Applicable*

Former Corporation Name (*Extra-Provincial Corporations only*) ☐ *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
☒ English *anglais* ☐ French *français*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). ▶ No. of Schedule(s): 0

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check 1 this box. Schedule(s) A and K are not required (MGS). ▶ ☒ No Change

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person
Phil Marley

Title D ☐ Director O ☐ Officer P ☐ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Taxation Year End

Exempt From Filing (EFF) Corporations Tax Return Declaration

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)

This EFF Declaration must be filed for each taxation year that the corporation is exempt from filing and must be filed within 6 months after the corporation's taxation year end.

Criteria for exempt from filing status:

a) has filed a federal Income Tax Return (T2) with Canada Revenue Agency for the taxation year;
b) had no Ontario taxable income for the taxation year (subject to the provisions in Note 2 below);
c) had no Ontario Corporations Tax payable for the taxation year;
d) was a Canadian-controlled private corporation throughout the taxation year (i.e. generally a private corporation with 50% or more shares owned by Canadian residents as defined by the *Income Tax Act* (Canada));
e) has provided its Canada Revenue Agency business number to the Ministry of Revenue; and
f) is **not** subject to the Corporate Minimum Tax (i.e. alone or as part of an associated group whose total assets exceed $5 million or whose total revenue exceeds $10 million for the taxation year).

Note 1: Filing of this declaration and the Annual Return does not constitute the filing of a Corporations Tax Return under section 75 of the *Corporations Tax Act*.

Note 2: The following loss situations will require otherwise EFF corporations to file a CT23 tax return complete with all related schedules and financial statements:

- If a corporation has a loss in the current taxation year that is to be carried back and applied to a previous taxation year(s), regardless of whether the loss is the same as for federal purposes or not, a CT23 tax return is required for the current taxation year. The corporation must also provide information indicating that the loss is to be carried back and specify the year and the amount of loss to be carried back to each taxation year.
- If a corporation has a prior year loss, that is not the same for both federal and Ontario purposes and the corporation is applying a loss carryforward from the prior year to the current year, a CT23 tax return is required for the current taxation year, and if not previously filed, a CT23 tax return for the prior taxation year in which the loss was incurred is also required. Although a tax return for the loss year is not required where the loss is not being applied, the ministry will accept the filing of a tax return for a loss year at the time the loss is incurred.
- If a corporation has a prior year loss, that is the same for both federal and Ontario purposes, but in the current taxation year the corporation is applying a different amount of loss for Ontario than the loss amount being applied for federal income tax purposes, the corporation is required to file a CT23 tax return for the current taxation year only.

The following 3 items MUST be completed for EFF declarations only. In cases where the Annual Return, which includes page 1, is **also** being filed, completion of these fields is **not** required.

1. Corporation's Mailing Address

City Province Country Postal code

2. Ontario Corporation No. (MGS)

3. Canada Revenue Agency Business No. RC

I, ______________________________ declare that:

The above corporation meets **all** of the exempt from filing criteria (a) through (f) above for the taxation year and therefore qualifies under the *Corporations Tax Act* as exempt from filing an Ontario Corporations Tax Return.

Signature	Title/Relationship to Corporation	Telephone number ( ) -	Date

Please note that making a false statement to avoid compliance with the *Corporations Tax Act* is an offence which can result in a penalty and/or fine.

If you check "Yes" to ALL of the following criteria, you are eligible to file the CT23 Short-Form Corporations Tax Return. To obtain a copy, contact the Ministry Information Centre at the numbers listed on page 2 of the Guide.

Yes	No	
☒	☐	(a) The corporation is a Canadian-controlled private corporation (CCPC) throughout the taxation year. Indicate Share Capital with full voting rights owned by Canadian Residents (nearest whole percentage) 0 %
☐	☒	(b) The corporation's taxable income for the taxation year is $200,000 or less. For a taxation year with less than 51 weeks, taxable income must be grossed-up. (*Refer to Guide.*)
☒	☐	(c) The corporation is **not** a member of a partnership/joint venture or a member of an associated group of corporations during the taxation year.
☐	☒	(d) The corporation's taxation year ends on or after January 1 2001, and its gross revenue and total assets are each $1,500,000 or less and the corporation is not a financial institution; or The corporation's taxation year commences after September 30, 2001, and its gross revenue and total assets are each $3,000,000 or less and the corporation is not a financial institution.
☐	☒	(e) The corporation is **not** claiming a tax credit other than the Incentive Deduction for Small Business Corporations (IDSBC), Co-operative Education Tax Credit (CETC), Graduate Transitions Tax Credit (GTTC) or Apprenticeship Training Tax Credit (ATTC).
☒	☐	(f) The corporation's Ontario allocation factor is 100%.

Note: Family Farm or Fishing corporations that have a taxation year ending on or after January 1, 2000 and are **not** subject to the Corporate Minimum Tax, may also use the **CT23 Short-Form Corporations Tax Return** if the corporation checks "Yes" to a), b), c), e) and f) above.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (1) box(es) and complete required information.

Type of Corporation

1
- 1 ☒ Canadian-controlled private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))
- 2 ☐ Other Private
- 3 ☐ Public
- 4 ☐ Non-share Capital
- 5 ☐ Other (*specify*)

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 0 %

2
- 1 ☐ Family Farm corporation s.1(2)
- 2 ☐ Family Fishing corporation s.1(2)
- 3 ☐ Mortgage Investment corporation s.47
- 4 ☐ Credit Union s.51
- 5 ☐ Bank Mortgage subsidiary s.61(4)
- 6 ☐ Bank s.1(2)
- 7 ☐ Loan and Trust corporation s.61(4)
- 8 ☐ Non-resident corporation s.2(2)(a) or (b)
- 9 ☐ Non-resident corporation s.2(2)(c)
- 10 ☐ Mutual Fund corporation s.48
- 11 ☐ Non-resident owned investment corporation s.49
- 12 ☐ Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)
- 14 ☐ Bare Trustee corporation
- 15 ☐ Branch of Non-resident s.63(1)
- 16 ☐ Financial institution prescribed by Regulation only
- 17 ☐ Investment Dealer
- 18 ☐ Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale
- 19 ☐ Hydro successor, municipal electrical utility or subsidiary of either
- 20 ☐ Producer and seller of steam for uses other than for the generation of electricity
- 21 ☐ Insurance Exchange s.74.4
- 22 ☐ Farm Feeder Finance Co-operative corporation
- 23 ☐ Professional corporation (incorporated professionals only)

- ☐ This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)
- ☐ Amended Return
- ☐ Taxation year end change - Canada Revenue Agency approval required
- ☐ Final taxation year up to dissolution (*Note: for discontinued businesses, see guide.*)
- ☐ Final taxation year before amalgamation
- ☐ The corporation has a floating fiscal year end
- ☐ There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario
- ☐ There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

  If checked, date control was acquired ______________
- ☐ The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)
- ☐ First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)
- ☐ Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
☐	☒	Was the corporation inactive throughout the taxation year?
☒	☐	Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
☐	☒	the Carry-back of a Loss?
☒	☐	an Overpayment?
☐	☒	a Specified Refundable Tax Credit?
☐	☒	Are you a Member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use Head Office no.) ______________

Ontario Employer Health Tax Account no. (Use Head Office no.) ______________

Specify major business activity
Hydro Distribution

Income Tax

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

Net income (loss) for Ontario purposes (per reconciliation schedule, page 15)	From	690±	1,720,332
Subtract: Charitable donations		1 -	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*		2 -	
Subtract: Taxable dividends deductible, per federal Schedule 3		3 -	
Subtract: Ontario political contributions *(Attach schedule* 2A) (Int.B. 3002R)		4	
Subtract: Federal Part VI.1 tax ______ X 3		5 -	
Subtract: Prior years' losses applied - Non-capital losses	From	704-	
Net capital losses (page 16) From 715 ______ X inclusion rate 50.000000 % =		714-	
Farm losses	From	724-	
Restricted farm losses	From	734-	
Limited partnership losses	From	754-	
Taxable income (Non-capital loss)		10 =	1,720,332
Addition to taxable income for unused foreign tax deduction for federal purposes	11 +		
Adjusted taxable income 10 + 11 (if **10** is negative, enter **11**)	20 =	1,720,332	

Taxable Income

Number of days in Taxation Year

From 10 (or 20) 1,720,332	X30 100.0000 (Ontario Allocation)	% X 12.5% X	33 ______ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷	73 365 (Total Days) =	29+	
From 10 (or 20) 1,720,332	X30 100.0000 (Ontario Allocation)	% X 14.0% X	34 365 (Days after Dec. 31, 2003) ÷	73 365 (Total Days) =	32+	240,846

Income Tax Payable (before deduction of tax credits) **29 + 32** — 40 = 240,846

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (1) ☒ Yes ☐ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))			50	1,715,715
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	51 +	1,720,332		
Add: Losses of other years deducted for federal purposes (fed.s.111)	52 +			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	53 -			
	=	1,720,332	54	1,720,332
Federal Business limit (line 410 of the T2 return) for the year before the application of fed.s.125(5.1)	55 +	400,000		

Ontario Business Limit Calculation

320,000 X 31 ______ (Days after Dec. 31, 2002 and before Jan. 1, 2004) ÷ ** 365 =+ 46 ______

400,000 X 34 365 (Days after Dec. 31, 2003) ÷ ** 365 =+ 47 400,000

Business limit for Ontario purposes 46 + 47 = 44 400,000 X 48 100.0000 % = 45 400,000 (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.)

Income eligible for the IDSBC From 30 100.0000 % X 56 400,000 (***Ontario Allocation; Least of **50**, **54** or **45**) 60 = 400,000

** Note: Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

*** Note: Adjust accordingly for a floating taxation year and use 366 for a leap year.*

**** Note: Ontario Allocation for IDSBC purposes may differ from **30** if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Calculation of IDSBC Rate

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
7.0% X	31		÷ 73	365 =	89 +	
8.5% X	34	Days after Dec. 31, 2003: 365	÷ 73	Total Days: 365 =	90 +	8.5000
IDSBC Rate for Taxation Year 89 + 90					78 =	8.5000
Claim From 60		400,000	X From 78	8.5000 %	70 =	34,000

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount in **114** below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

*** Taxable Income of the corporation** From **10** (or **20** if applicable) **80** + 1,720,332

If you are a member of an associated group (?) **81** ☒ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
			+ 82	
			+ 83	
			+ 84	

Aggregate Taxable Income **80 + 82 + 83 + 84**, etc. **85** 1,720,332

Number of days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days			
320,000 X	31		÷ 73	365 =	115 +		
400,000 X	34	Days after Dec. 31, 2003: 365	÷ 73	Total Days: 365 =	116 +	400,000	
				115 + 116	=	400,000	**114** - 400,000
(If negative, enter nil)							**86** = 1,320,332

Number of Days in Taxation Year

		Days after Dec. 31, 2002		Total Days		
Calculation of Specified Rate for Surtax 4.667% X	38	365	÷ 73	365 =	97 +	4.6670
From 86 1,320,332	X From 97	4.6670 % =			87 =	61,620
From 87 61,620	X From 60	400,000	÷ From 114	400,000	88 =	61,620

Surtax Lesser of **70** or **88** **100** = 34,000

**** Note: Short Taxation Years -*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

Income Tax *continued from Page 5*

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits		120 +	
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From	56 -	400,000

Add: Adjustment for Surtax on Canadian-controlled private corporations
From **100** 34,000 ÷ From **30** 100.0000 % ÷ From **78** 8.5000 % = **121** 400,000
*Ontario Allocation

Lesser of **56** or **121**	122 +	400,000
120 - 56 + 122	130 =	

Taxable income	From	10 +	1,720,332
Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC)	From	56 -	400,000
Add: Adjustments for Surtax on Canadian-controlled private corporations	From	122 +	400,000
Subtract: Taxable income 10 X Allocation % to jurisdictions outside Canada		140	
Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses		141	4,617
10 - 56 + 122 - 140 - 141		142 =	1,715,715

Claim — **Number of Days in Taxation Year**

				Days		Total Days		
143 (Lesser of **130** or **142**)	X From 30	100.0000 % X 1.5% X (*Ontario Allocation)	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)		÷ 73	365	=	154 +
143 (Lesser of **130** or **142**)	X From 30	100.0000 % X 2.0% X (*Ontario Allocation)	34 (Days after Dec. 31, 2003)	365	÷ 73	365	=	156 +

M&P claim for taxation year **154 + 156** — 160

***Note:** Ontario Allocation for M&P Credit purposes may differ from **30** if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

161 =

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

162 =

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* — 170

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit **175** — Credit Claimed **180**

Subtotal of Income Tax 40 - 70 + 100 - 110 - 160 - 161 - 162 - 170 - 180

190 = 240,846

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.
Eligible Credit from **5620** OITC Claim Form *(Attach original Claim Form)* — 191 +

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.
Eligible Credit from **5798** CT23 Schedule 113 *(Attach Schedule 113)* — 192 +

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)
Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. Name of Production 204
Eligible Credit from **5850** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 193 +

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From **6596** 194
Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005.
Eligible Credit from **6598** CT23 Schedule 115 *(Attach Schedule 115)* — 195 +

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)
Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.
Eligible Credit from **6900** OBPTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* — 196 +

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)
Applies to labour relating to computer animation and special effects on an eligible production.
Eligible Credit from **6700** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 197 +

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)
Applies to qualifying R&D expenditures under an eligible research institute contract.
Eligible Credit from **7100** OBRITC Claim Form *(Attach original Claim Form)* — 198 +

Ontario Production Services Tax Credit (OPSTC) (s.43.10)
Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.
Eligible Credit from **7300** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 199 +

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)
Applies to qualifying labour expenditures of eligible products for the taxation year.
Eligible Credit from **7400** of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* — 200 +

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)
Applies to qualifying expenditures in respect of eligible Canadian sound recordings.
Eligible Credit from **7500** OSRTC Claim Form
*(Attach **both** the original Claim Form and the Certificate of Eligibility)* — 201 +

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From **5896** 202
Applies to employment of eligible apprentices.
Eligible Credit from **5898** CT23 Schedule 114 *(Attach Schedule 114)* — 203 +

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 — 220 =

Specified Tax Credits *Applied to reduce Income Tax* — 225 =

Income Tax **190 - 225 OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* — 230 = 240,846

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8**. If CMT is not applicable, transfer amount in **230** to Income Tax in **Summary** section on **Page 17**.

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8**.

Corporate Minimum Tax (CMT)

Total Assets of the corporation	240 + 13,369,334		
Total Revenue of the corporation		241 +	20,132,476

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (1) 242☐ (Yes)

Name of associated corporation (Canadian & foreign)	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243	+ 244
			+ 245	+ 246
			+ 247	+ 248

Aggregate Total Assets 240 + 243 + 245 + 247 , etc.	249 = 13,369,334	
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.		250 = 20,132,476

Determination of Applicability

Applies if ***either*** Total Assets **249** exceeds $5,000,000 ***or*** Total Revenue **250** exceeds $10,000,000.

Short Taxation Years - Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation - The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101.**

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - CMT Base From Schedule 101 **2136** 831,968 X From **30** 100.0000 % X 4% **276** = 33,279
If negative, enter zero — Ontario Allocation

Subtract: Foreign Tax Credit for CMT purposes *(Attach schedule)*		277
Subtract: Income Tax	From 190 -	240,846
Net CMT Payable (if negative, enter Nil on page 17.)		280 =

If **280** is less than zero and you do not have a CMT credit carryover, transfer **230** from **Page 7** to **Income Tax Summary, on Page 17.**

If **280** is less than zero and you have a CMT credit carryover, complete A & B below.

If **280** is greater than or equal to zero, transfer **230** to **Page 17** and transfer **280** to **Page 17, and to Part 4 of Schedule 101: Continuity of CMT Credit Carryovers**

CMT Credit Carryover available From Schedule 101 — From **2333**

Application of CMT Credit Carryovers

A.	Income Tax (before deduction of specified credits)			From 190 +	240,846
	Gross CMT Payable	From 276 +	33,279		
	Subtract: Foreign Tax Credit for CMT purposes	From 277 -			
	If 276 - 277 is negative, enter NIL in 290	=	33,279	290 -	33,279
	Income Tax eligible for CMT Credit			300 =	207,567
B.	Income Tax (after deduction of specified credits)			From 230 +	240,846
	Subtract: CMT credit used to reduce income taxes			310 -	
	Income Tax			320 =	240,846

Transfer to Page 17

***If A & B apply,* 310 *cannot exceed the lesser of* 230, 300 *and your CMT credit carryover available* 2333.**

***If only B applies,* 310 *cannot exceed the lesser of* 230 *and your CMT credit carryover available* 2333.**

Capital Tax *(Refer to Guide and Int.B. 3011R)*

*If your corporation is a Financial Institution (s.58(2)), complete lines **480** and **430** on page 10 then proceed to page 13.*

*If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in **480** and **430** are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in **550** on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s. 2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	350 +	6,880,984
Retained earnings (if deficit, deduct) (Int.B. 3012R)	351 ±	1,344,287
Capital and other surpluses, excluding appraisal surplus (Int.B. 3012R)	352 +	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	353 +	1,907,721
Bank loans (Int.B. 3013R)	354 +	
Bankers acceptances (Int.B. 3013R)	355 +	
Bonds and debentures payable (Int.B. 3013R)	356 +	
Mortgages payable (Int.B. 3013R)	357 +	
Lien notes payable (Int.B. 3013R)	358 +	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	359 +	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	360 +	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	361 +	418,459
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	362 +	
Subtotal	370 =	10,551,451
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	371 -	
Deductible R&D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	372 -	
Total Paid-up Capital	380 =	10,551,451
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	381 -	
Electrical Generating Corporations Only - All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	382 -	
Net Paid-up Capital	390 =	10,551,451

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	402 +	
Mortgages due from other corporations	403 +	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	404 +	
Loans and advances to unrelated corporations	405 +	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	406 +	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	407 +	
Total Eligible Investments	410 =	

continued on Page 10

Capital Tax *continued from Page 9*

Total Assets (Int.B. 3015R)

Total Assets per balance sheet	420+	13,369,334
Mortgages or other liabilities deducted from assets	421+	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	422+	
Subtract: Investment in partnership(s)/joint venture(s)	423-	
Total Assets as adjusted	430=	13,369,334
Amounts in **360** and **361** (if deducted from assets)	440+	
Subtract: Amounts in **371, 372** and **381**	441-	
Subtract: Appraisal surplus if booked	442-	
Add or Subtract: Other adjustments (specify on an attached schedule)	443±	
Total Assets	450=	13,369,334

Investment Allowance (410 ÷ 450) X 390	Not to exceed 410	460=	
Taxable Capital 390 - 460		470=	10,551,451

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)

Gross Revenue of the corporation	20,132,476		
Corporation's Share of partnership(s)/joint venture(s) Gross Revenue *(Attach schedule)*			
Aggregate of Gross Revenue	20,132,476	480	20,132,476
Total Assets (as adjusted)	From	430	13,369,334

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*
Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).
Enter NIL in **550** on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

		Days		Total Days		
7,500,000 X	36	Days after Dec. 31, 2004 and before Jan. 1, 2006:	÷ 73	365	= 501 +	
10,000,000 X	37	Days after Dec. 31, 2005 and before Jan. 1, 2007:	÷ 73	365	= 502 +	
12,500,000 X	38	Days after Dec. 31, 2006 and before Jan. 1, 2008: 365	÷ 73	365	= 504+	12,500,000
15,000,000 X	39	Days after Dec. 31, 2007:	÷ 73	365	= 505+	
				Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505	503 =	12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

		Days		Total Days		
0.3 % X	556	Days before Jan. 1, 2007:	÷ 73	365	= 511	%
0.285 % X	557	Days after Dec. 31, 2006 and before Jan. 1, 2009: 365	÷ 73	365	= 512	0.2850 %
Capital Tax Rate		511 + 512			= 516	0.2850 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If **430** and **480** on page 10 are both $3,000,000 or less, enter NIL in **550** on page 12 and complete the return from that point.

C2. If Taxable Capital in **470** is **equal to or less than the TCD** in **503**, enter NIL in **550** on page 12 and complete the return from that point.

C3. If Taxable Capital in **470** **exceeds the TCD** in **503**, complete the following calculation and transfer the amount from **523** to **543** on page 12, and complete the return from that point.

+ From **470** ________________
- From **503** ________________
= **471** ________________ x From **30** ______ % x From **516** 0.2850 % x **555** ________________ / 365 (366 if leap year) = **523** + ________________

Ontario Allocation — Capital Tax Rate — Days in taxation year; *If floating taxation year, refer to Guide.* — *Transfer to 543 on page 12 and complete the return from that point*

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either **509** or **524** and complete this section before you can calculate your Capital Tax calculation under either Section E or Section F.

D1. ☐ **509** (1 if applicable)	All corporations that you are associated with do **not** have a permanent establishment in Canada. If Taxable Capital **470** on page 10 is equal to or less than the TCD **503** on page 10, enter NIL in **550** on page 12 and complete the return from that point. If Taxable Capital **470** on page 10 exceeds the TCD **503** on page 10, proceed to **Section E**, enter the TCD amount in **542** in Section E, and complete Section E and the return from that point.
D2. ☐ **524** (1 if applicable)	One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada. You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group. The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year. In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

D2. Calculation Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital from **470** on page 10 — From 470 + ______

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Taxable Capital
			+ 531
			+ 532
			+ 533

Aggregate Taxable Capital **470 + 531 + 532 + 533**, etc. — 540 =

If **540** above is equal to or less than the TCD **503** on page 10, the corporation's Capital Tax for the taxation year, is NIL. Enter NIL in **523** in section E below, as applicable.
If **540** above is greater than the TCD **503** on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From **470** ______ ÷ From **540** ______ X From **503** ______ 541 =
*Transfer to **542** in Section E below*

Ss.69(2.1) Election Filed

591 (1 if applicable) — **Election filed.** *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital **540** above, exceeds the TCD **503** on page 10.

Complete the following calculation and transfer the amount from **523** to **543**, and complete the return from that point.

+ From
470 ______
\- 542 ______
= 471 ______ x From 30 ______ % x From **516** 0.2850 % x 555 ______ = 523 + ______

Ontario Allocation — Capital Tax Rate — Days in taxation year *365 (366 if leap year) — **Total Capital Tax for the taxation year**

*Transfer to **543** and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+From 470 ______ X From 30 ______ % x From **516** 0.2850 % = 561 + ______

Ontario Allocation — Capital Tax Rate

\- Capital tax deduction from **995** relating to **your corporation's** Capital Tax deduction, on Schedule 591 — From 995
562 = ______

Capital Tax 562 ______ X 555 ______ = 563 + ______

Days in taxation year *365 (366 if leap year) — **Total Capital tax for the taxation year**

*Transfer to **543** and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits	543 =
Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)*	546 -
Capital Tax 543 - 546 *(amount cannot be negative)*	550 =

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions Only

For taxation years commencing **after May 4, 1999** enter NIL in **550** on page 12, and complete the return from that point.

1.2 Other than Credit Unions

*(Retain details of calculations for amounts in boxes **565** and **570**. Do not submit with this tax return.)*

565 ______ x **567** 0.5700 % x From **30** ______ % x **555** ______ (Days in taxation year / *365 (366 if leap year)) = **569**+ ______

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1; Capital Tax Rate(1) *(Refer to Guide)*; Ontario Allocation

570 ______ x **571** ______ % x From **30** ______ % x **555** ______ (Days in taxation year / *365 (366 if leap year)) = **574**+ ______

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount; Capital Tax Rate(2) *(Refer to Guide)*; Ontario Allocation

Capital Tax for Financial Institutions - other than Credit Unions (before Section 2) 569 + 574 575= ______

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments 585 ______

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (1) ☐ Yes

Capital Tax - Financial Institutions 575 - 585 586= ______

*Transfer to **543** on Page 1:*

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements **587** ______ x 2% **588**= ______
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in **588** and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in **588**.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* **589** ______

Premium Tax 588 - 589 **590**= ______

Transfer to Page 17

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net income (loss) for federal income tax purposes, per federal T2 Schedule 1 600± 1,720,332 *Transfer to Page 15*

Add:

Federal capital cost allowance	601 +	569,567	
Federal cumulative eligible capital deduction	602 +	2,196	
Ontario taxable capital gain	603 +	4,617	
Federal non-allowable reserves. Balance beginning of year	604 +	80,000	
Federal allowable reserves. Balance end of year	605 +	80,000	
Ontario non-allowable reserves. Balance end of year	606 +	80,000	
Ontario allowable reserves. Balance beginning of year	607 +	80,000	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	608 +		
Federal resource allowance *(Refer to Guide)*	609 +		
Federal depletion allowance	610 +		
Federal foreign exploration and development expenses	611 +		
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	617 +		

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

		Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
612	X 5/12.5 X	33	÷ 73	365	=	633 +

		Days after Dec. 31, 2003		Total Days		
612	X 5/14.0 X	34 365	÷ 73	365	=	634 +

Total add-back amount for Management fees, etc. 633 + 634 =	613 +			
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	615 +			
Add any negative amount in 473 from Ont. CT23 Schedule 161	616 +			
Federal allowable business investment loss	620 +			
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	614 +			
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614	=	896,380	640	896,380

Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under **675**)	650 +	569,567
Ontario cumulative eligible capital deduction	651 +	2,196
Federal taxable capital gain	652 +	4,617
Ontario non-allowable reserves. Balance beginning of year	653 +	80,000
Ontario allowable reserves. Balance end of year	654 +	80,000
Federal non-allowable reserves. Balance end of year	655 +	80,000
Federal allowable reserves. Balance beginning of year	656 +	80,000
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	657 +	
Ontario depletion allowance	658 +	
Ontario resource allowance *(Refer to Guide)*	659 +	
Ontario current cost adjustment *(Attach schedule)*	661 +	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	675 +	
Subtotal of deductions for this page 650 to 659 + 661 + 675	681	896,380

Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net income (loss) for federal income tax purposes, per federal Schedule 1			From 600 ±	1,720,332
Total of Additions on page 14			From 640 =	896,380
Sub Total of deductions on page 14	From 681 =	896,380		

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(*Applies* only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year 662 ______

ONTTI Gross-up deduction calculation:
From 662 ______ Gross-up of CCA x 100/ 30 From 100.0000 Ontario Allocation - From 662 ______ 663 =

Workplace Child Care Tax Incentive (WCCT)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 665 ______ x 30% x 100/ 30 From 100.0000 Ontario Allocation 666 =

Workplace Accessibility Tax Incentive (WATI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 667 ______ x 100% x 100/ 30 From 100.0000 Ontario Allocation 668 =

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(*Applies* to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: 670 ______ x 30% x 100/ 30 From 100.0000 Ontario Allocation 671 =

Educational Technology Tax Incentive (ETTI)
(*Applies* to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: 672 ______ x 15% x 100/ 30 From 100.0000 Ontario Allocation 673 =

Ontario allowable business investment loss	678 +			
Ontario Scientific Research Expenses claimed in year in 477 from Ont. CT23 Schedule 161	679 +			
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	677 +			
Total of other deductions allowed by Ontario *(Attach schedule)*	664 +			
Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664	=	896,380	680	896,380
Net income (loss) for Ontario Purposes 600 + 640 - 680			690 =	1,720,332

Transfer to Page 4

Continuity of Losses Carried Forward

	Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year	700 (2)	710 (2)	720 (2)	730	740	750
Add: Current year's losses (7)	701	711	721	731	741	751
Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal	703	713	723	733	743	753
Subtract: Utilized during the year to reduce taxable income	704 (2)	715 (2)(4)	724 (2)	734 (2)(4)	744 (4)	754 (4)
Expired during the year	705		725	735	745	
Carried back to prior years to reduce taxable income (5)	706 (2) To Pg 17	716 (2) To Pg 17	726 (2) To Pg 17	736 (2) To Pg 17	746	
Subtotal	707	717	727	737	747	757
Balance at End of Year	709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first)	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year	817 (9)	860 (9)		850	870
801 8th preceding taxation year	818 (9)	861 (9)		851	871
802 7th preceding taxation year	819 (9)	862 (9)		852	872
803 6th preceding taxation year	820	830	840	853	873
804 5th preceding taxation year 2002/12/31	821	831	841	854	874
805 4th preceding taxation year 2003/12/31	822	832	842	855	875
806 3rd preceding taxation year 2004/12/31	823	833	843	856	876
807 2nd preceding taxation year 2005/12/31	824	834	844	857	877
808 1st preceding taxation year 2006/12/31	825	835	845	858	878
809 Current taxation year 2007/12/31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from **11** if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in **709** must equal total of **829** + **839**.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance.**
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss	910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income. **Predecessor Corporation's Tax Account No. (MOF)** / **Taxation Year Ending**				
i) 3rd preceding 901 2004/12/31	911	921	931	941
ii) 2nd preceding 902 2005/12/31	912	922	932	942
iii) 1st preceding 903 2006/12/31	913	923	933	943
Total loss to be carried back	From 706	From 716	From 726	From 736
Balance of loss available for carry-forward	919	929	939	949

Summary

Income Tax	From 230 or	320+	240,846
Corporate Minimum Tax	From	280+	
Capital Tax	From	550+	
Premium Tax	From	590+	
Total Tax Payable		950=	240,846
Subtract: Payments		960-	275,441
Capital Gains Refund (s.48)		965-	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*		985-	
Specified Tax Credits *(Refer to Guide)*		955-	
Balance		970=	(34,595)
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*		975=	34,595
Apply to		980	

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Phil Marley

Title
President & CEO

Full Residence Address

City

Province	Country	Postal Code

Signature

Date 2008/04/28

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Ontario

Ministry of Revenue

Corporation Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Summary of Dispositions of Capital Property

2005 and later taxation years

Schedule 6

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Midland Power Utility Corporation	(MOF) 1800345	2007/12/31

- **For a corporation that has disposed of capital property or claimed an allowable business investment loss, or both, in the taxation year.**
- **This schedule may be used to make a designation under section 34(10) of the *Corporations Tax Act* provided the corporation has made a designation under paragraph 111(4) (e) of the *Income Tax Act* (Canada), if control of the corporation has been acquired by a person or group of persons.**

Part A: Designation under section 34(10) of the *Corporations Tax Act*

Complete part A if there are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e) of the *Income Tax Act* (Canada) or section 34(10) of the *Corporations Tax Act*.

Property	Class #	Date of disposition	Proceeds of disposition	Adjusted cost base	Other adjustments	Designated amount	Gain or loss

Part B: Inter-provincial asset transfers

Complete part B if there was any disposition shown on the schedule as a result of a federal election under section 85 of the *Income Tax Act* (Canada) that transferred assets to a non-arm's length corporation with a permanent establishment in another Canadian jurisdiction.

Property	Class #	Corporation name of transferee/or	Date of disposition	Cost of asset in other jurisd.	Name of other jurisdiction	Allocation ratio to other jurisdictions	Ontario elected amount	Gain or loss

1 Type of capital property	2 Date of acquisition	3 Date of disposition	4 Proceeds of disposition	5 Ontario adjusted cost base (ACB)	6 Outlays and expenses	7 Ontario gain (or loss) (4 - (5 + 6))

Part 1 - Shares

No. of shares	Name of corporation	Class of shares	2	3	4	5	6	7
	Enerconnect				9,234			9,234
							Totals	9,234 A

Part 2 - Real estate *(Do not include losses on depreciable property.)*

Municipal address	2	3	4	5	6	7
Address: City: Province Country Postal code						
					Totals	B

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Midland Power Utility Corporation	(MOF) 1800345	2007/12/31

1 Type of capital property	2 Date of acquisition	3 Date of disposition	4 Proceeds of disposition	5 Ontario adjusted cost base	6 Outlays and expenses	7 Ontario gain (or loss) (4 - (5 + 6))

Part 3 - Bonds

Face value	Maturity date	Name of issuer	2	3	4	5	6	7
							Totals	C

Part 4 - Other properties *(Do not include losses on depreciable property)*

Description	2	3	4	5	6	7
					Totals	D

Part 5 - Personal-use property

Description of capital property	2	3	4	5	6	7
					Net gain or (loss)	E

Note: *Losses are not deductible.*

Part 6 - Listed personal property

Description	2	3	4	5	6	7
					Totals	

Deduct: Unapplied listed personal property losses from other years -

Net gain (or loss) F

Note: *Net listed personal property losses may only be applied against listed personal property gains.*

Part 7 - Property qualifying for and resulting in an allowable business investment loss

Name of small business corporation	Shares or debt	Date of acquisition	Date of disposition	Proceeds of disposition	Ontario adjusted cost base (ACB)	Outlays and expenses	Ontario loss
	N/A						
						Net Loss	G

Note: Properties listed in part 7 should not be included in any other Part of Schedule 6.

Allowable business investment loss X 50.000000 % = G1

*Transfer to **678** of the CT23 or CT8*

Determining capital gains and capital losses

Total of A to F (Do not include F if it is a loss)		9,234	
Add: Amount (if any) of capital gain reserve opening balance from Schedule 13	+		
Capital gain dividend received in the year	+		
Subtotal	=	9,234	
Deduct: Amount (if any) of capital gain reserve closing balance from Schedule 13	-		
Gain or Loss (excluding Allowable Business Investment Losses)	=	9,234	H

Determining taxable capital gains

Gain or Loss (excluding Allowable Business Investment Losses)		9,234	H
Deduct:			
Gain on donations (made to charities other than private foundations) of securities listed on a prescribed stock exchange			
realized prior to May 2, 2006 x 50%	-		
realized after May 1, 2006			
Gain on donations of ecologically sensitive land			
realized prior to May 2, 2006 x 50%	-		
realized after May 1, 2006			
Gains or Loss		9,234	I

*Include 100% of the losses in box **711** of the CT23 or CT8*

Taxable capital gains 9,234 X 50.000000 % Q = 4,617 J

*Transfer to **603** of the CT23 or CT8*

OS7
Schedule 7

Ontario aggregate investment income

Aggregate and foreign investment income tax calculation

	Foreign investment income	Aggregate investment income	
The eligible portion of taxable capital gains included in income for the year		4,617	A
Eligible portion of allowable capital losses for the year (including allowable business investment loss)			B
Net capital losses claimed at line 125 on page 3 of the T2 return			C
Total of amounts B and C			D
Amount A minus amount D (if negative, enter nil)	<NIL>	4,617	E
Taxable dividends deductible from T2S(3)			
Other property income (include income from a specified investment business carried on in Canada other than income from a source outside Canada)			
Total income from property			F
Exempt income			G
Amounts received from NISA Fund No. 2 that was included in computing the corporation's income for the year			H
Taxable dividends deductible from T2S(3)			
Minus: related expenses			
Taxable dividends deductible from T2S(3) after deducting related expenses *			I
Business income from an interest in a trust that is considered property income under paragraph 108(5)(a) of the *Income Tax Act*			J
Total of amounts G, H, I, and J			K
Amount F minus amount K			L
Total of amount E plus amount L		4,617	M
Total losses from property (include losses from a specified investment business carried on in Canada other than a loss from a source outside Canada)			N
Amount M minus amount N (if negative, enter nil)	R <NIL>	S 4,617	

* If negative, enter amount in brackets, and add instead of subtract.

Part 2 - Specified partnership income

A Partnership name	Start of fiscal period	End of fiscal period	B Total income (loss) from active business	C Corporation's share of amount in column B

D Adjustments (add reserves deducted under ss.34.2(5) and deduct expenses)	E Corporation's income (loss) of the partnership (column C plus column D)	F # of days in the partnership's fiscal period	G Prorated business limit (column C ÷ column B) x [business limit* x (column F ÷ 365)]**	H Column E **minus** column G (if negative, enter "0")	I Lesser of columns E and G (if negative, enter "0")
Total			Total		

Corporation's losses for the year from an active business carried on in Canada (other than as a member of a partnership) - enter as a positive amount ______ 1

Specified partnership loss of the corporation for the year - enter as a positive amount (total of all negative amounts in column E) ______ 2

Totals of line 1 and 2 ______ ▸ ______ J

Total of column H or line J, whichever is less ______

Specified partnership income ______ K

* Use $200,000 for days in fiscal periods prior to October 1, 2001.
Use $280,000 for days in fiscal periods after September 30, 2001 but before January 1, 2003.
Use $320,000 for days in fiscal periods after December 31, 2002 but before January 1, 2004.
Use $400,000 for days in fiscal periods after December 31, 2003.

** When a partnership carries on more than one business, one of which generates income and another realizes a loss, the partnership loss is not netted against the partnership's income.

OS7
Schedule 7

Ontario aggregate investment income

Part 3 - Determination of partnership income for Ontario puposes

Corporation's share of partnership income from active businesses carried on in Canada for Ontario puposes after deducting related expenses - from column E above (if the net amount is negative, enter "0" on line P)			L
Add: Specified partnership loss (from line 2 above)			M
Subtotal			N
Deduct: Specified partnership income (from line K above)			O
Partnership income (enter on line T below)			P

Part 4 - Income from active businesses carried on in Canada

Net income for income tax purposes		1,720,332	Q
Deduct: Foreign business income after deducting related expenses *			
Taxable capital gains **minus** allowable capital loss ** (amount A **minus** amount B in part 1)	4,617		
Net property income = amount F **minus** amounts G, H and N * (part 1)	R		
Personal services business income after deducting related expenses *			
	4,617	4,617	
Net amount		1,715,715	S
Deduct Partnership income (line P above)			T
Income from active business carried on in Canada for Ontario puposes (enter on line 50 of the CT23 return - if negative, enter "0")		1,715,715	U

* If negative, enter amount in brackets, and add instead of subtract.
** This amount may only be negative to the extent of any allowable business investment losses.

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance

Schedule 8

ONTARIO CAPITAL COST ALLOWANCE

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Midland Power Utility Corporation	1800345	2007/12/31

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year	3 Cost of acquisitions during the the year (See note 1 below)	4 Net adjustments	5 Proceeds of dispositions during the year	6 Ontario undepreciated capital cost (col 2 + 3 or col 2 - 4 - 5)	7 50% rule (See note 2 below)	8 Reduced undepreciated capital cost (col 6 - 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (col 8 x 9 or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (col 6 - 12)
1	5,825,396	37,224			5,862,620	18,612	5,844,008	4			233,760	5,628,860
8	167,216	63,991			231,207	31,996	199,211	20			39,842	191,365
10	295,517	151,987		27,500	420,004	62,244	357,760	30			107,328	312,676
12	20,821	146,270			167,091	73,135	93,956	100			93,956	73,135
45	8,741	14,388			23,129	7,194	15,935	45			7,171	15,958
47	591,435	1,004,881			1,596,316	502,441	1,093,875	8			87,510	1,508,806
								Totals			569,567	

Enter in box **650** on the CT23

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
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Oshawa ON L1H 8E9

Ontario Cumulative Eligible Capital Deduction

Schedule 10

For taxation years 2002 and later

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Midland Power Utility Corporation	(MOF) 1800345	2007/12/31

- **For use by a corporation that has eligible capital property.**
- **A separate cumulative eligible capital account must be kept for each business.**

Part 1 - Calculation of current year deduction and carry-forward

Ontario Cumulative eligible capital - balance at beginning of taxation year *(if negative, enter zero)*				+ 31,377	A
Add: Cost of eligible capital property acquired during the taxation year	+	B			
Other adjustments	+	C			
B + C	=	x 3/4	=		D
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002		x 1/2	=-		E
D minus E *(if negative, enter zero)*			=	+	F
Amount transferred on amalgamation or wind-up of subsidiary				+	G
Subtotal A + F + G				= 31,377	H
Deduct: Ontario proceeds of sales (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	+	I			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) of the *Income Tax Act* (Canada)	+	J			
Other adjustments	+	K			
I + J + K	=	x 3/4		=-	L
Ontario cumulative eligible capital balance H minus L				= 31,377	M

*If **M** is negative, enter zero at line **Q** and proceed to **Part 2**, page 2.*

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business				N	
From **M**	31,377				
From **N** -					
Current year deduction M minus N	31,377	x 7%*	= + 2,196	O	
N + O			= 2,196	▸ - 2,196	P

Note: The maximum current year deduction is 7%. Any amount up to the maximum deduction of 7% may be claimed. For taxation years starting after December 21, 2000, the deduction may not exceed the maximum amount prorated for the number of days in the taxation year divided by 365 or 366 days.

*Enter amount in box **651** of the CT23*

Ontario cumulative eligible capital - closing balance M minus **P** *(if negative, enter zero)* = 29,181 Q

See page 2 - part 2

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Midland Power Utility Corporation	(MOF) 1800345	2007/12/31

Part 2 - Amount to be included in income arising from disposition

Complete this part only if the amount at line M is negative

Amount from line M above *show as a positive amount; not negative.*							R
Total of cumulative eligible capital deductions from income for taxation years beginning after June 30, 1988			+		1		
Total of all amounts which reduced cumulative eligible capital in the current or prior years under subsection 80 (7)			+		2		
Total of cumulative eligible capital deductions claimed for taxation years beginning before July 1, 1988	+	3					
Negative balances in the cumulative eligible capital account that were included in income for taxation years beginning before July 1, 1988	-	4					
Deduct line 4 from line 3 (*if negative, enter zero*)	=		+		5		
Total lines **1 + 2 + 5**			=		6		
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line **1**		7					
Amounts at **Line** Z from Ontario Schedule 10 of previous taxation years ending after February 27, 2000 (*This will be* ***Line T*** *in earlier versions of this schedule.*)	+	8					
Total lines 7 + 8	=		-		9		
Deduct line **9** from line **6** (*if negative, enter zero*)			=			-	S
R minus S (*if negative, enter zero*)						=	T
From Line **5** x 1/2						= -	U
T minus U (*if negative, enter zero*)						=	V
From **V** x 66.6667 %						=	W
Lesser of line **R** and **S**						= +	Z
Amount to be included in income W + Z							

Ontario

Ministry of Finance

Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No.	Taxation Year End
Midland Power Utility Corporation	(MOF) 1800345	2007/12/31

For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes

Part 1 - Capital gains reserves

Description of property	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Totals	A	B	C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 - Other reserves

Description	Ontario balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Ontario balance at the end of the year
Reserve for doubtful debts	80,000		80,000
Reserve for undelivered goods and services not rendered			
Reserve for prepaid rent			
Reserve for December 31, 1995 income			
Reserve for refundable containers			
Reserve for unpaid amounts			
Other tax reserves			
Totals	D 80,000	E	F 80,000

The amount from **D** plus the amount from **E** should be entered in **607** of the CT23.

The amount from **F** should be entered in **654** of the CT23.

Part 3 - Continuity of non-deductible reserves

Reserve	Ontario opening balance and transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
Reserve for doubtful debt	80,000				80,000
Totals	80,000				80,000
	*Enter in box **653** of the CT23*				*Enter in box **606** of the CT23*

Ontario Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Midland Power Utility Corporation	1800345	2007/12/31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Due to shareholder	44,789
Due to shareholder	1,122,519
Long-term customer and retailer deposits	161,990
Long term construction deposits	211,895
Other long-term liabilities	52,884
Post retirement benefits	127,541
Current portion of deposits	186,103
Total	1,907,721

*Transfer to **353** on the CT23*

Ontario Ministry of Finance
Corporations Tax
PO Box 620
33 King Street West
Oshawa ON L1H 8E9

Paid-Up Capital: Other Reserves

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Midland Power Utility Corporation	1800345	2007/12/31

Description of Reserves NOT ALLOWED as a Deduction for Income Tax	Balance Beginning of the Year	Add	Deduct	Transfer on Amalgamation or Wind-up of Subsiduary	Balance at the End of the Year
NBV/UCC difference	464,113		45,654		418,459
				Total	418,459

*Transfer to **361** on the CT23*

Ontario Ministry of Finance
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Authorizing or Cancelling a Representative

Complete this form to:

- **authorize** the release of confidential information about the Corporations Tax, Mining Tax or Electricity Act account(s) to the representative named below.
- **cancel** an existing authorization.

Part 1 Client Information

Legal name: Midland Power Utility Corporation
Phone number: (705) 526-9361
Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: PO Box 820
City: Midland
Province/Territory: ON
Postal code: L4R 4P4

This authorization applies to the following statute(s) and account number(s).

- [X] Corporations Tax Act: 1800345
- [ ] Mining Tax Act
- [ ] Electricity Act

Part 2 Authorize the release of information to a representative

Name of representative (If a firm, name of firm.): BDO Dunwoody LLP
Phone number: (705) 726-6331
Fax number: (705) 722-6588
Mailing address
Apt./Suite/Unit no. Street number and name / PO Box, RR: 300 lakeshore Drive, Suite 300
City: Barrie
Province/Territory: ON
Postal code: L3Z 2B2

If your representative is a firm, and you want a specific person in the firm to represent you, state their name and title.
If you do not identify a specific individual in the firm, you are authorizing the Ministry of Finance to deal with anyone from that firm.

Title: Pres. CEO

Part 3 Authorization scope and applicable years

- [X] Representative to **deal fully** on your behalf with the Ministry of Finance.

or

- [ ] Representative to **deal in a limited manner** on your behalf, for matters specified here. (e.g., account inquiry, applications, annual returns, payments, etc.) ▼

- [X] Representative to act for **all years**, including all previous and future years.

or

- [ ] Representative to act for **specific year or years** (describe). ▼

Part 4 Cancel the release of information to a representative

Name of representative (If a firm, name of firm.)
Last
First

If your representative is an individual within a firm, state their name and title.
Name of person in firm
Last
First
Title

Part 5 Signature *This form will not be accepted unless it is completed fully, signed and dated.*

I authorize the Ministry of Finance to:

- release confidential information about the tax accounts specified in Part 1 and to deal with the representative named in Part 2 in the manner described in Part 3; and/or
- cancel an existing authorization as described in Part 4.

Name
Last: Marley
First: Phil
Title / Relationship to Corporation: President & CEO
Phone number: (705) 526-9361
Signature
Date: 2008/04/28

Ontario

Ministry of Finance

Corporations Tax
PO Box 642
33 King Street West
Oshawa ON L1H 8T1

CT23 - Certification Form Diskette Filing

Corporations Tax Account Number
1800345

Return I.D. # (Ministry Use Only)

Please check appropriate boxes if applicable:

- [ ] First year of filing
- [ ] Final taxation year up to Dissolution
- [ ] Change of Control fed.s.249(4)
- [ ] Amended return
- [ ] Final taxation year before Amalgamation
- [ ] Taxation year end has changed (approval by CCRA required)
- [ ] Floating Fiscal year end
- [ ] Exempt from filing
- [x] Subject to CMT

Date Control was acquired:

Date of incorporation
2002/05/01

Return for taxation year
Start 2007/01/01
End 2007/12/31

CCRA Business No.
865749386RC0001

Jurisdiction Incorporated
Ontario

Corporation's legal name and mailing address
Midland Power Utility Corporation
Care of
16894 Highway 12
Address
PO Box 820

Change of information? Yes ☐ No ☒

City	Province	Country	Postal code
Midland	ON	CA	L4R 4P4

Transmitter Details

Transmitter number	A0051680
Transmitter name	BDO Dunwoody LLP
Name of person to contact	David Capin
Telephone number	(705) 445-4421
Facsimile number	(705) 445-6691
Transmitter Address	202-186 Hurontario Street Collingwood, Ontario L9Y 3Z5
Disk Reference Number	

Aggregate of Total Revenue	210	20,132,476
Aggregate of Total Assets	209	13,369,334
Taxable Income (Non-capital Loss)	10	1,720,332
Total Tax Payable	950	240,846
Payments:	990	275,441
Enclosed:		
Apply to: Year		
Apply Amount:		

975 Refund: Yes ☒ No ☐

If Yes, Due to:

Loss Carryback:	Yes ☐	No ☒
Overpayment:	Yes ☒	No ☐
Refundable tax credit	Yes ☐	No ☒

Certification

I am an authorized signing officer of the Corporation. I certify that this Return, including all schedules and statements filed with or as part of this Return, has been examined by me and is a true, correct and complete Return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the Corporations Tax Act. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name
Phil Marley

Title
President & CEO

Full Residence address

City

Province	Country	Postal code

Signature

Phone Number
(705) 526-9361

Date
2008/04/28

ProFile Version 2006.7.0 Approval code 080G

Payment Advice

Corporations Tax Account Number	1800345
Date of Incorporation	2002/05/01
Corporation Name	
Midland Power Utility Corporation	

Enter the amount of payment and indicate taxation year.

Taxation Year End	Payment amount
	$
2007/12/31	$
Total Payment	$

Submit your cheque (drawn on a Canadian financial institution) or money order in Canadian Funds, payable to: The Minister of Finance

Send to: Ontario Ministry of Finance
Corporations Tax
P.O. Box 642
33 King Street West
Oshawa ON L1H 8T1

Incomplete information will result in a delay processing an assessment.

Ontario tax instalments

Instalment base

Year-end	Estimate for current year 2008/12/31	First instalment base 2007/12/31	Second instalment base 2006/12/31
Taxable income		1,720,332	1,435,394
Base amount of tax		240,846	200,955
Small business tax credit		34,000	34,000
Surtax on CCPCs		34,000	34,000
Manufacturing and processing profits credit			
Foreign tax credit			
Specified tax credits			
Other tax credits			60,420
Income tax payable		240,846	140,535
Corporate minimum tax payable			
Capital tax payable			1,906
Premium tax payable			
Total tax payable		240,846	142,441
Days in taxation year	365	365	365
Tax payable adjusted for short taxation years		240,846	142,441
Estimated tax credits for the current year			
Instalment base		240,846	142,441
Monthly payment		20,071	11,870
Quarterly payment		60,212	35,610

Instalment payment options

- [ ] 1. based on estimated taxes for the current year
- [ ] 2. based on the first instalment base
- [x] 3. based on the first and second instalment base
- [ ] 4. instalments are not required

Instalment payments

Date	Instalments required	Instalments paid	Instalments payable
2008/01/31	11,870		
2008/02/29	11,870		
2008/03/31	21,711		
2008/04/30	21,711		67,162
2008/05/31	21,711		21,711
2008/06/30	21,711		21,711
2008/07/31	21,711		21,711
2008/08/31	21,711		21,711
2008/09/30	21,711		21,711
2008/10/31	21,711		21,711
2008/11/30	21,711		21,711
2008/12/31	21,711		21,711
Total	240,850		240,850

EXHIBIT 5 - DEFERAL AND VARIANCE ACCOUNTS

Deferral and Variance Accounts

Description of Deferral and Variance Accounts

Utility Deferral Accounts

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

Description: This account captures the variance between OEB Cost Assessments amount approved in 1999 versus the actual OEB Cost Assessments charged.

1508 Other Regulatory Assets - Sub-account Pension Contributions

Description: To record the pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (“OMERS”) for the period from January 1, 2005 to April 30, 2006.

1550 LV Variance Account

Description: This account captures the variance between LV Chares billed by Hydro One Networks Inc. [H.O.N.I.] on Power bill and LV Charges billed to MPUC customers.

Calculation of Balances by Account

MPUC calculated the 2005, 2006 and 2007 ending balances as the actual balances at December 31, 2005, December 31, 2006 and December 31, 2007. We then added carrying costs to the balances for the 2008 Bridge Year and the 2009 Test Year. Attached on the pages following is the Deferral/Variance Account Table for the 2005, 2006, 2007 Years along with projections for the 2008 Bridge Year and 2009 Test Year.

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	-28,980	92,950	63,970	-3,322	-802	-4,124
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	50,718	-2,789	47,930			
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	35,893	-10,553	25,340			
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account						
1555-Smart Meters Capital Variance Account						
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-233,595	-176,550	-410,145	-534	-21,936	-22,471
1563-Account 1563 - Deferred PILs Contra Account	233,595	176,550	410,145	534	21,936	22,471
1565-Conservation and Demand Management Expenditures and Recoveries	4,569	-127,560	-122,990	27	66	92
1566-CDM Contra Account		122,898	122,898		92	92
1570-Qualifying Transition Costs	420,898	-35,463	385,435	86,663	-86,663	
1571-Pre-market Opening Energy Variance	547,697		547,697	105,888	39,708	145,596
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	295,095	167,705	462,799	51,826	24,192	76,018
1582-RSVAONE-TIME	51,471	12,681	64,153	4,750	4,099	8,849
1584-RSVANW	-79,642	-23,571	-103,214	3,420	535	3,955
1586-RSVACN	713,728	198,840	912,568	957	4,415	5,372
1588-RSVAPOWER	54,296	542,121	596,418	17,016	5,602	22,618
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**2,065,744**	**937,260**	**3,003,004**	**267,225**	**-8,756**	**258,468**

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	63,970	-14,928	49,043	-4,124	716	-3,408
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	47,930	-55,299	-7,370		-378	-378
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits	25,340	-25,340				
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account		6,619	6,619		-89	-89
1555-Smart Meters Capital Variance Account		-11,158	-11,158		-38	-38
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-410,145	68,916	-341,229	-22,471	-29,980	-52,450
1563-Account 1563 - Deferred PILs Contra Account	410,145	-68,916	341,229	22,471	29,980	52,450
1565-Conservation and Demand Management Expenditures and Recoveries	-122,990	113,422	-9,568	92		92
1566-CDM Contra Account	122,898	-113,422	9,476	92		92
1570-Qualifying Transition Costs	385,435	-385,435				
1571-Pre-market Opening Energy Variance	547,697	-547,697		145,596	-145,596	
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	462,799	-575,129	-112,330	76,018	-68,641	7,377
1582-RSVAONE-TIME	64,153	-50,547	13,606	8,849	-7,774	1,074
1584-RSVANW	-103,214	85,011	-18,202	3,955	-2,459	1,496
1586-RSVACN	912,568	-1,359,548	-446,980	5,372	-10,098	-4,726
1588-RSVAPOWER	596,418	-521,951	74,467	22,618	-1,356	21,262
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**3,003,004**	**-3,455,402**	**-452,399**	**258,468**	**-235,714**	**22,754**

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%

Deferral / Variance Account	1-Jan-2007 to 31-Dec-2007 Open. Principal	Changes	End. Principal	Open. Interest	Changes	End. Interest
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	49,043		49,043	-3,408	2,318	-1,090
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	-7,370	-303	-7,673	-378	-296	-675
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account	6,619	107,007	113,626	-89	2,870	2,780
1555-Smart Meters Capital Variance Account	-11,158	-2,274	-13,432	-38	-1,145	-1,183
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-341,229	-20,897	-362,126	-52,450	-17,601	-70,052
1563-Account 1563 - Deferred PILs Contra Account	341,229	20,897	362,126	52,450	17,601	70,052
1565-Conservation and Demand Management Expenditures and Recoveries	-9,568	9,568	-0	92		92
1566-CDM Contra Account	9,476	-9,476	-0	92	-92	0
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-112,330	-261,779	-374,109	7,377	-10,115	-2,738
1582-RSVAONE-TIME	13,606		13,606	1,074	656	1,730
1584-RSVANW	-18,202	276,529	258,327	1,496	7,284	8,780
1586-RSVACN	-446,980	-498,635	-945,615	-4,726	-31,150	-35,876
1588-RSVAPOWER	74,467	525,585	600,052	21,262	21,558	42,819
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**-452,399**	**146,223**	**-306,176**	**22,754**	**-8,113**	**14,642**

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%	31-Dec-2007 Balance			1-Jan-08 to 30-Apr-08		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	49,043	-1,090	47,953	548		48,501
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	-7,673	-675	-8,347	-86		-8,433
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account	113,626	2,780	116,406	1,269		117,675
1555-Smart Meters Capital Variance Account	-13,432	-1,183	-14,615	-150		-14,765
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-362,126	-70,052	-432,177	-4,044		-436,221
1563-Account 1563 - Deferred PILs Contra Account	362,126	70,052	432,177	4,044		436,221
1565-Conservation and Demand Management Expenditures and Recoveries	-0	92	92			92
1566-CDM Contra Account	-0	0	0			0
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-374,109	-2,738	-376,847	-4,178		-381,025
1582-RSVAONE-TIME	13,606	1,730	15,336	152		15,488
1584-RSVANW	258,327	8,780	267,107	2,885		269,992
1586-RSVACN	-945,615	-35,876	-981,491	-10,559		-992,050
1588-RSVAPOWER	600,052	42,819	642,871	6,701		649,572
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**-306,176**	**14,642**	**-291,534**	**-3,419**		**-294,953**

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%	1-May-08 to 31-Dec-08			1-Jan-09 to 30-Apr-09		
Deferral / Variance Account	**Interest**	**Other**	**Balance**	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	1,095		49,596	548		50,144
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	-171		-8,605	-86		-8,690
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account	2,538		120,213	1,269		121,481
1555-Smart Meters Capital Variance Account	-300		-15,065	-150		-15,215
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-8,087		-444,309	-4,044		-448,352
1563-Account 1563 - Deferred PILs Contra Account	8,087		444,309	4,044		448,352
1565-Conservation and Demand Management Expenditures and Recoveries			92			92
1566-CDM Contra Account			0			0
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-8,355		-389,380	-4,178		-393,557
1582-RSVAONE-TIME	304		15,792	152		15,944
1584-RSVANW	5,769		275,761	2,885		278,646
1586-RSVACN	-21,119		-1,013,169	-10,559		-1,023,729
1588-RSVAPOWER	13,401		662,973	6,701		669,674
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**-6,838**		**-301,791**	**-3,419**		**-305,210**

Deferral/Variance Account Table

Interest Rate (from sheet Y1) = 3.35%	31-Dec-07 Balance + Interest to 30-Apr-09			1-May-09 to 31-Dec-09		
Deferral / Variance Account	**31-Dec-07**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1505-Unrecovered Plant and Regulatory Study Costs						
1508-Other Regulatory Assets	47,953	2,191	50,144	1,095		51,239
1510-Preliminary Survey and Investigation Charges						
1515-Emission Allowance Inventory						
1516-Emission Allowances Withheld						
1518-RCVARetail	-8,347	-343	-8,690	-171		-8,862
1520-Power Purchase Variance Account						
1525-Miscellaneous Deferred Debits						
1530-Deferred Losses from Disposition of Utility Plant						
1540-Unamortized Loss on Reacquired Debt						
1545-Development Charge Deposits/ Receivables						
1548-RCVASTR						
1550-LV Variance Account	116,406	5,075	121,481	2,538		124,019
1555-Smart Meters Capital Variance Account	-14,615	-600	-15,215	-300	-82,200	-97,715
1556-Smart Meters OM&A Variance Account						
1560-Deferred Development Costs						
1562-Deferred Payments in Lieu of Taxes	-432,177	-16,175	-448,352	-8,087		-456,440
1563-Account 1563 - Deferred PILs Contra Account	432,177	16,175	448,352	8,087		456,440
1565-Conservation and Demand Management Expenditures and Recoveries	92		92			92
1566-CDM Contra Account	0		0			0
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1572-Extraordinary Event Costs						
1574-Deferred Rate Impact Amounts						
1580-RSVAWMS	-376,847	-16,710	-393,557	-8,355		-401,912
1582-RSVAONE-TIME	15,336	608	15,944	304		16,248
1584-RSVANW	267,107	11,539	278,646	5,769		284,415
1586-RSVACN	-981,491	-42,237	-1,023,729	-21,119		-1,044,847
1588-RSVAPOWER	642,871	26,802	669,674	13,401		683,075
1592-2006 PILs/Taxes Variance						
2425-Other Deferred Credits						
TOTAL	**-291,534**	**-13,676**	**-305,210**	**-6,838**	**-82,200**	**-394,248**

2009 Rate Rider

MPUC is requesting a Rate Rider to allow recovery of Account 1508 – Other Regulatory Assets and Account 1550 – LV Variance Account providing for a two year recovery of $171,625 or $85,812 per year. Attached on the pages following is a calculation of the Rate Rider

Rate Rider

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
1508-Other Regulatory Assets	50,144	kWh's	11,422	6,343	31,983	274	4	118
1550-LV Variance Account	121,481	kWh's	27,671	15,367	77,485	665	9	285
Sub-Total for recovery	**171,625**		**39,093**	**21,709**	**109,468**	**939**	**13**	403
1590-Recovery of Regulatory Asset Balances (residual)								
Total Recoveries Required (2 years)	**171,625**		**39,093**	**21,709**	**109,468**	**939**	**13**	403
Annual Recovery Amounts	85,812		19,546	10,855	54,734	469	6	202
Annual Volume			49,791,737	27,650,878	332,681	3,052	44	513,550
Proposed Rate Rider			**$0.0004**	**$0.0004**	**$0.1645**	**$0.1538**	**$0.1423**	**$0.0004**
per			kWh	kWh	kW	kW	kW	kWh

[1] per sheet C6

Allocators	Data Source	2009 Projection Total	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
Customers / Connections	C1	8,448	6,018	729	103	1,564	22	12
kWh's	C1	218,595,966	49,791,737	27,650,878	139,428,070	1,195,783	15,948	513,550
Distribution Revenue (existing rates)	C4	3,105,208	1,788,196	495,150	787,134	25,259	501	8,968
Distribution Revenue (proposed rates)	F4	3,582,721	1,811,424	559,442	1,118,884	72,013	5,553	15,406
Transmission Connection Revenue	C2	1,427,036	376,536	191,431	849,401	6,024	89	3,555
Approved Recoveries	C5	100.0%	42.7%	12.7%	44.4%	0.0%	0.0%	0.2%

Method of Recovery

An appropriate allocator (e.g. number of customers, kWs, kWhs) has been assigned to each variance/deferral account ("Account"). The actual Account balance as at December 31, 2007 is then apportioned to each customer class based on Test Year volume projections for the allocator. Example: if kWhs are assigned as the allocator for an account, and the Load Forecast for the Test Year indicates that 30% of kWh's will be consumed by the Residential customer class, then 30% of the Account balance is allocated to the Residential class.

For each customer class, the sum of allocated balances over all Accounts selected for disposition is calculated. Example: if two Accounts are selected for disposition and the amounts allocated to the Residential customer class were $50,000 for Account #1 and $30,000 for Account #2, then the sum of allocated balances for the Residential class would be $80,000.

For each customer class, the sum of allocated balances is divided by two to derive the annual recovery amount needed to clear the balances over two years. Example: if the sum of allocated balances for the Residential class is $80,000, the annual recovery amount to clear the balances over two years would be $40,000.

For each customer class, the rate rider is calculated as the annual recovery amount divided by the 2009 Test Year forecast for the distribution rate volume metric, with the result rounded to the nearest one-hundredth of a cent. Example: if the distribution rate volume metric for the Residential customer class is kWh's, and 100,000,000 kWh's are forecast for the Residential class in the Test Year, then the rate rider for the Residential class would be $0.0004 (=$40,000 divided by 100,000,000).

Disposition of Variance and Deferral Accounts

MPUC has calculated the ending balance for each variance account as the actual balance as at December 31, 2005, 2006 and 2007. These balances agree with our audited financial statements for the years 2005, 2006 and 2007.

Carrying Costs up to April 30, 2009 have been calculated and added to determine the final totals for disposal in this Rate Application, in the amount of $171,625. MPUC proposes to dispose of these balances over a two year period commencing May 1, 2009 and ending on April 30, 2011.

EXHIBIT 6 - COST OF CAPITAL AND RETURN

Cost of Capital and Rate of Return

Overview of Cost of Capital and Return

The purpose of this evidence is to summarize the method and cost of financing MPUC's capital requirements for the 2009 test year. To accommodate these capital requirements MPUC will be seeking additional debt which will bring our debt to equity ratio closer to Board approved ratios. Although not a part of this Application, additional debt will be incurred as MPUC moves forward with the Smart Metering Infrastructure as required by the Ministry of Energy.

Capital Structure

Table 58 2006 EDR Board Approved

	Dollars $	Ratio(%)	Cost Rate (%)	Deemed Rate (%)
Long-term debt: Town of Midland	1,722,519	18.4	4.79	
Common Equity	7,648,732	81.6		9
TOTAL	9,371,251			

Table 59 2008 Bridge Year

	Dollars $	Ratio(%)	Cost Rate (%)	Deemed Rate (%)
Long-term debt: Town of Midland	1,122,519	11.9	3.99	
Common Equity	8,291,041	88.1		9
TOTAL	9,413,560			

Table 60 2009 Test Year

	Dollars $	Ratio(%)	Cost Rate (%)	Deemed Rate (%)
Long-term debt: Town of Midland	1,122,519	9.5	3.99	
Long-term debt: Financial institution	2,000,000	17.0	5.0	
Common Equity	8,635,814	73.5		8.57
TOTAL	11,758,333			

For rate setting purposes MPUC has a current deemed capital structure of 53.33% debt, 46.67% Equity, in compliance with the Ontario Energy Board's Report on Cost of Capital and 2nd Generation Incentive Regulation of Ontario Electricity Distributors dated December 20, 2006. MPUC is requesting Board approval of a deemed capital structure of 56.67% debt, 43.33% equity including an equity return of 8.57%. The Ontario Energy Board Report indicates that Distributors will be required to phase-in a 60% debt and 40% equity capital structure that must be completed by 2010. MPUC is requesting this change in capital structure and associated return on equity primarily to support of the Report of the Board. MPUC believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

For 2009, MPUC has used a return on equity of 8.57% consistent with the equity return approved for the 2008 cost of service applications. MPUC has also used the short term debt rate of 4.47% based on the 2008 EDR Board decisions. The long term debt rate is calculated as 4.64% which is based on the expected debt cost of $144,789 divided by the debt balance of $3,122,519 for the 2009 year as shown below:

Table 61 2009 Debt Balances

Description	Effective Rate	Days o/s in 2009	Debt Balance	2009 Cost	2009 Ending Balance
Note Payable to Shareholder	3.99%	365	1,122,519	44,789	1,122,519
Debenture/Loan to Bank, etc.	5.00%	365	2,000,000	100,000	2,000,000
TOTAL	4.64%		3,122,519	144,789	3,122,519

MPUC's weighted average cost of capital of 6.33% is summarized below. MPUC believes the requested capital structure and equity return will provide continued access to long-term debt at reasonable rates.

Table 62 Average Cost of Capital

Description	Portion	Cost Rate	Weighted Avg
Long Term Debt	52.67%	4.64%	2.44%
Short Term Debt	4.00%	4.47%	0.18%
Common Equity	43.33%	8.57%	3.71%
Total	100%		6.33%

Cost of Debt

As indicated in Exhibit 6, Tab 1, Schedule 1, the 2009 Debt Balances Table provides the detailed calculation of MPUC's forecast long-term debt costs. MPUC expects to incur additional third party, unsecured debt in 2009 to accommodate the capital programs as set out in Exhibit 2 herein. This additional debt will be by way of debenture and will be prudently negotiated taking into consideration any premiums and discounts. This debt moves the capital structure closer to the "deemed" amount as set by the Ontario Energy Board.

The Short Term Debt Rate used at the time of filing of this Rate Application was the debt rate based on the 2008 EDR Board decisions. MPUC expects that the deemed short-term debt rate would be updated based on Consensus Forecasts and Bank of Canada's data as the Ontario Energy Board sees fit.

Long Term Debt

MPUC current debt is by way of a promissory note payable to the Corporation of the Town of Midland. Interest is payable on the note on the 30th day following December 31st of each year in which principal is owing under the note. The interest rate payable in any given year is the Government of Canada 10-year bond rate posted by the Bank of Canada on December 31st of each year.

The terms of this note include prepayment at any time or times without notice or bonus.

Long-term debt cost information for the historical and bridge periods is recorded at $1.7M for the 2006 EDR, $1.2M for the years 2006, 2007 and 2008.

Short Term/Unfunded Debt

MPUC has no short term/unfunded debt.

Preference Shares

MPUC has no preference shares issued or outstanding.

Common Equity

MPUC has 1,000 common shares issued in favour of The Corporation of the Town of Midland.

Return on Equity

The calculations used to determine the return on equity are consistent with the rate recently approved for the 2008 cost of service rate applications and MPUC understands this rate will be updated in accordance with the “Report to the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors” issued December 20, 2006.

EXHIBIT 7 - CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Calculation of Revenue Deficiency or Surplus

Overview of Utility Revenue

This exhibit presents an overview of the revenue deficiency or surplus calculations process for the 2009 test year. The Revenue/Sufficiency/Deficiency Summary was provided in Exhibit 1, Tab 1, Schedule 9, however, it is being reproduced below. This Summary sets out the revenue deficiency for the 2009 Test Year.

Table 63 Summary of Revenue Sufficiency/Deficiency – 2009 Projection

Utility Income	(see below)	88,005
Utility Rate Base		12,318,654
Indicated Rate of Return		0.71%
Requested / Approved Rate of Return		6.33%
Sufficiency / (Deficiency) in Return		(5.62%)
Net Revenue Sufficiency / (Deficiency)		**-692,329**
Provision for PILs/Taxes		-204,993
Gross Revenue Sufficiency / (Deficiency)		**-897,322**
Deemed Overall Debt Rate		*4.64%*
Deemed Cost of Debt		*322,861*
Utility Income less Deemed Cost of Debt		*-234,855*
Return On Deemed Equity		*(4.40%)*
UTILITY INCOME		
Total Net Revenues		2,916,530
OM&A Expenses		2,058,900
Depreciation & Amortization		735,424
Taxes other than PILs / Income Taxes		34,200
Total Costs & Expenses		2,828,524
Utility Income before Income Taxes / PILs		88,005
PILs / Income Taxes		
Utility Income		**88,005**

Determination of Revenue Deficiency or Surplus

Determination of Net Utility Income

On the page previous to this page is the Revenue Sufficiency/Deficiency Summary which provides details of Utility Income for the 2009 Test Year.

Statement of Rate Base

Exhibit 2, Tab 1, Schedule 2 includes the Rate Base Summary Table (see Table 16). It is reproduced below and sets out the Total Rate Base for the 2006 EDR, 2006 Actual Year, 2007 Actual Year, 2008 Bridge Year and the 2009 Test Year.

Table 64 Rate Base Summary

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Net Capital Assets in Service:					
Opening Balance		5,729,993	5,735,722	6,630,550	8,521,501
Ending Balance		5,735,722	6,630,550	8,521,501	10,484,616
Average Balance	5,251,869	5,732,858	6,183,136	7,576,025	9,503,058
Working Capital Allowance	2,662,646	2,670,771	2,791,219	2,826,009	2,815,595
Total Rate Base	**7,914,515**	**8,403,628**	**8,974,355**	**10,402,034**	**12,318,654**
Expenses for Working Capital					
Eligible Distribution Expenses:					
3500-Distribution Expenses - Operation	272,722	374,509	352,987	392,900	455,700
3550-Distribution Expenses - Maintenance	306,118	336,041	283,582	338,200	353,900
3650-Billing and Collecting	412,100	379,313	451,821	420,400	435,800
3700-Community Relations	15,581	23,774	15,073	5,700	5,600
3800-Administrative and General Expenses	673,755	655,050	650,232	744,600	807,900
3950-Taxes Other Than Income Taxes	28,420	34,495	31,306	32,900	34,200
Total Eligible Distribution Expenses	1,708,695	1,803,182	1,785,000	1,934,700	2,093,100
3350-Power Supply Expenses	16,042,281	16,001,955	16,823,128	16,905,361	16,677,534
Total Expenses for Working Capital	17,750,976	17,805,137	18,608,129	18,840,061	18,770,634
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**2,662,646**	**2,670,771**	**2,791,219**	**2,826,009**	**2,815,595**

Indicated Rate of Return

Exhibit 7, Tab 1, Schedule 1 provides the Revenue Sufficiency/Deficiency Summary which shows the indicated rate of return for MPUC for the 2009 Test Year.

Requested Rate of Return

Exhibit 7, Tab 1, Schedule 1 provides the Revenue Sufficiency/Deficiency Summary which shows the requested rate of return for MPUC for the 2009 Test Year.

Deficiency or Sufficiency in Revenues

Exhibit 7, Tab 1, Schedule 1 provides the Revenue Sufficiency/Deficiency Summary for MPUC for the 2009 Test Year.

Gross Deficiency or Sufficiency in Revenues

Exhibit 7, Tab 1, Schedule 1 provides the Revenue Sufficiency/Deficiency Summary which shows the Gross Deficiency in Revenues for MPUC for the 2009 Test Year.

EXHIBIT 8 - COST ALLOCATION

Cost Allocation

Proposed Method

MPUC proposes to use the Cost Allocation Method as approved by the Ontario Energy Board. The following is from the MPUC cost allocation informational filing dated February 15, 2007

Introduction

On September 29, 2006 the Ontario Energy Board (the "OEB") issued the Board Directions on Cost Allocation Methodology for Electricity Distributors (“the Directions”). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors (“the Guidelines”), the Cost Allocation Model (“the Model”) and User Instruction (the Instructions”) for the Model. MPUC has prepared this information filing consistent with MPUC’s understanding of the Directions, the Guidelines, the Model and the Instructions.

The main purpose of this cost allocation filing is to provide evidence to show the MPUC rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

In the mid 1980’s, Ontario Hydro, the regulator at the time, completed the last cost allocation study that reflected the distribution function but this was an integrated cost study. The integrated study reviewed the full costs of providing electricity to customers which included energy, transmission and distribution. Distribution represented only around 15% of the total costs reviewed. The results of this study assisted Ontario Hydro in developing the Rate Setting Guidelines that were used by Municipal Electric Utilities to develop the bundled rates they charged customers up until around 2000.

Under the Energy Competition Act, 1998, the electricity industry in Ontario was separated into Generation, Transmission and Distribution companies. Along with this separation the rates also needed to be unbundled to reflect the structure of the new companies. The unbundling of distribution from generation and transmission was completed in the 2000 to 2001 timeframe using the Electricity Distribution Rate Handbook Rate and the Rate Unbundling and Design Model (i.e. the RUD model). The Rate Handbook and RUD model provided a method to unbundle distribution rates from the other rates by rate classification but it did not determine whether the unbundled rates collected the cost of providing service to the rate classification. The current cost allocation process is the first time a cost allocation study has been conducted in Ontario that focuses completely on distribution to determine whether or not the distribution rates are collecting the cost of providing service to the rate classifications.

MPUC has followed the Board's filing requirements and on the pages following this page is a copy of the Manager's Summary filed with the Board by MPUC and a copy of Run 2 of the Cost Allocation Model which was filed as an informational filing only.

MPUC's Cost Allocation Filing was made up of a Run 1 and a Run 2. An optional Run 3 was not conducted. For MPUC, Run 1 reflects the rate classifications as they were prior to May 1, 2006. Prior to May 1, the Unmetered Scattered Load ("USL") customers were included in the General Service < 50 kW rate classification. Run 2 has the USL customers pulled out of the General Service < 50 kW class to form a class of their own which is consistent with the current rate classifications used by MPUC.

Midland Power Utility Corporation

MANAGER'S SUMMARY

(Licence # ED-2002-0541)

(Cost Allocation EB No. EB-2007-0002)

February 15, 2007

Overview

On March 9, 2005 electricity distributors were advised by the Ontario Energy Board ("OEB") of a cost allocation review based "primarily on the existing rate classifications and a limited number of rate design issues".

In September, 2005, the OEB issued a staff discussion paper that require electricity distributors to complete new cost allocation studies to confirm that distribution rates for each customer class remain just and reasonable. The updated filings will be used to consider the need for adjustments to the current share of distribution costs paid by various classes of ratepayers.

Description of Distributor

Name of the distributor:	Midland Power Utility Corporation.
Current licence number:	ED-2002-0541
Communities served:	Midland
Adjacent distributors:	Hydro One; Barrie Hydro, Tay Hydro
Characteristics:	Urban – high density
Embedded/Host:	Embedded – Market Participant
Mailing Address:	16984 Highway #12, P.O. Box 820, Midland, Ontario, L4R 4P4
Key Contact:	Phil Marley, President & CEO Tel.: (705)526-9362 ext 204 Fax: (705)526-7890 e-mail: pmarley@midlandpuc.on.ca

Midland Power Utility Corporation ("MPUC") is a licensed electricity distributor and holds OEB licence number ED-2002-0541. MPUC owns and operates electricity distribution facilities within the boundaries of the Town of Midland. MPUC's service area is within the Town of Midland's geographic location. Hydro One services a small portion of customers located within the Town of Midland boundaries.

The distributor serving the areas adjacent to MPUC's service area is Hydro One Networks Inc., Barrie Hydro Distribution Inc. and Tay Hydro Electric Distribution Company Inc. MPUC's service area is urban in nature with a population of approximately 17,000 residents. As of December 31, 2006, MPUC served 6,621 customers, of which 826 are commercial.

MPUC is an embedded distributor to Hydro One Networks Inc. except for load transfers.

Chapter 1.2 Filing Completeness

This filing by Midland Power Utility Corporation (MPUC) is made in accordance with the Board Directions on Cost Allocation Methodology For Electricity Distributors. MPUC has followed the OEB's common cost allocation methodology and used the default values and settings in both Run 1 and Run 2.

1.5.3 Rate Classification Information

There are no changes to the rate classifications since the 2004 test year.

1.5.7 Summary of the Cost allocation Filing

On Sheet I3, Trial Balance Data, MPUC has reallocated the balance of account 1840 Underground Conduit to account 1845 Underground Conductors and Devices. Due to inadvertence the Underground Conductors and Devices were erroneously recorded in account 1840 Underground Conduit. MPUC does not have Underground Conduit Assets.

On Sheet I3, Trial Balance Data, MPUC reallocated $38,131 from account 1860, Meters to account 1820, Distribution Station Equipment to reflect the costs associated with Wholesale Metering Points as required on Sheet I4, Breakout Assets Account 1820-3.

Chapter 2.0 MPUC Customer Rate Classification for the Filings

Run 1 incorporates Midland Power Utility Corporation Board approved 2006 EDR customer rate classifications. Costs and revenue components from the approved 2006 EDR were used. Customer groupings, including their load profiles reflect those in the 2006 EDR.

Customer class consists of the following:

- Residential
- GS < 50
- GS > 50 Regular
- Street Light
- Sentinel

Chapter 2.2.2 Unmetered Scattered Load (USL)

In Run 1, MPUC used approach one (i) and USL was treated as part of the GS<50 kW rate classification for allocating costs for USL customers.

Chapter 2.3.2 Elimination of Legacy Time of Use ("TOU") Rates

MPUC does not have TOU Rates.

Chapter 2.4 Optional Run 3

MPUC is not filing an optional Run 3.

Chapter 3 Load Data

MPUC arranged to get an analysis of its load profiles from Hydro One.

MPUC also undertook an updated residential appliance saturation survey jointly with its alliance partners of Cornerstone Hydro Electric Company ("The CHEC Group"). The summarized results were provided to Hydro One as part of the "Grouping" to develop MPUC-specific load profiles. In addition, customer data for the years 2004 and 2005 were provided to Hydro One in order to comply with Hydro One's requirements for weather normalization. MPUC used the Hydro One weather normalizing methodology to normalize its load profile.

Chapter 4.1 Test Year and Revenue

MPUC inputs into the model came from our approved 2006 EDR, billing systems and operational reports. MPUC used a historical test year (2004) in its 2006 EDR application. The 2004 trial balance incorporating all approved tier 1 and tier 2 adjustments in the final 2006 EDR Board Decision, was used as the basis of the cost data for the cost allocation review filing.

There are no meter reading costs included in Account 5630– Outside Services Employed. All meter reading costs are included in Account 5310.

Chapter 4.1.7 Filing Questions

1. Capital Assets are amortized following generally accepted accounting principles. MPUC, at management's discretion, capitalizes items over $500 in aggregate costs on a per project/item basis, so long as the item in question has a useful life of more than one year.
2. Outside Services Employed (Account 5630) costs comprise of legal, audit, accounting and consulting services.
3. Customer Information System Expenses are currently recorded in:
4. Account# 5610 – Administration and Management salaries and
5. Account# 5315 – Customer Billing

Chapter 5 Direct Allocation

MPUC did not identify any distribution facilities of which 100% of its use can be tracked directly to a single rate classification. Therefore no direct allocation was applied.

Chapter 6.2.2.2 Definition and Application Guidance for Bulk

In discussions with Board staff, it was determined that MPUC does not have any Bulk assets.

Chapter 6.2.2.6 Supporting Distribution System Information

MPUC's distribution system does not include Bulk Assets as defined by the OEB Guidelines which are built to support the distribution system peak. MPUC has two 44kv feeders supplying GS> 50kW customers and municipal distribution stations. Because not one 44kV feeder supports the system peak our assets are not considered Bulk

Primary Assets include the sub-transmission system at 44kV system and distribution system at 2400 volts for the purposes of this model. Secondary Assets are defined as 750v or less.

MPUC has 27 customers that are fed from the 44kv line which we have classified as Primary Assets in this model which is below 50kV. Although the 27 customers are fed directly from the 44kV feeder, they are sharing the costs of the total distribution system for the purposes of this model.

A single line diagram is attached for your reference.

Chapter 6.3.1 Identifying Associated Costs by Function

MPUC does not own any assets with > 50 kV. Overhead and underground assets are recorded separately in the GL. In order to assign costs (by poles, overhead conductors and devices), typical overhead and underground installations were used. We then applied the km of line for the primary and secondary assets to these unit costs to establish a percentage to be applied to the corresponding accounts. Using this per unit cost, we applied it to our asset values to determine the costs to be allocated to each category of Overhead Primary, Overhead Secondary, Underground Primary and Underground Secondary costs by asset types. Depreciation by asset method complies with the recommended approach in the directions.

6.6.4 Direction – Breaking out of Contributed Capital in Filings

MPUC used the alternative approach to the allocation of contributed capital on sheet I4. A schedule is attached showing the allocation based on percentage of asset base – see attached spreadsheet App1 Item 68.

Contributed Capital is recorded net of Accumulated Amortization by MPUC. Therefore, Column H on Sheet I4 was populated with zero balances. No Accumulated Amortization for Contributed Capital is recorded by MPUC in Account 2105.

Chapter 7.7.2 Multiple-unit Dwellings' Filing Questions

1. There are 1015 individually metered Residential customers who reside in multi-unit dwellings and there are 296 distributor connection points which supply the multi-unit complexes.
2. There are approximately 160 individually metered General Service customers that are located in multi-unit complexes and 37 distributor connection points which supply the multi-unit complexes.
3. There are 84 individually metered mixed use customers (i.e. Residential and General Service) and 19 distributor connections which supply the multi-unit complexes

Chapter 8.1 Allocation of Demand Related Costs

Midland Power has no record of "non-technical" energy losses and is unaware of any significant issues. Therefore no estimate is available. Midland's loss factor in 2004 was 4.291% and is 6.51% in 2006.

General Comments on Filing Results

The expense allocation output for Street Light in particular seems erroneous in the model. This may be a result of a heavy weighting to the number of Street Light connections and demand usage for this particular customer class and no weighting within the current model of how all the customer classes benefit from Street Lights. This should be reviewed as a provincial issue where all LDCs will be impacted.

At this time, MPUC do not recommend any changes based on the Model outputs until further consideration to the impacts within Street Light customer class.

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Sheet I6 Customer Data Worksheet - Second Run

Total kWhs	238,052,475
Total kWs	396,265
Total Approved Distribution Revenue ($)	$2,790,896

			1	2	3	7	8	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
kWh from approved EDR model, Sheet 7-1, Col M	**CEN**	238,052,475	46,445,857	25,950,016	163,465,701	1,301,013	35,318	854,570
kW from approved EDR model, Sheet 7-1, Col S	**CDEM**	396,265	-	-	392,975	3,195	95	
kW, included in CDEM, from customers with line transformer allowance from approved EDR model, Sheet 6-3, Col P		269,708	-	-	269,708	-	-	
Optional - kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-	-	-	-	-	-	
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	238,052,475	46,445,857	25,950,016	163,465,701	1,301,013	35,318	854,570
kWh - 30 year weather normalized amount		227,684,822	46,923,467	26,667,302	152,181,398	1,082,401	27,917	802,338

Approved Distribution Rev from approved EDR, Sheet 7-1, Col AK + Sheet 7-3 Col H	CREV	$2,790,897	$1,582,535	$432,779	$736,272	$22,871	$2,188	$14,252
Bad Debt 3 Year Historical Average from Approved EDR Model	BDHA	$20,074	$10,334	$9,740	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$33,244	$21,509	$11,735	$0	$0	$0	
Weighting Factor - Services			1.0	2.0	10.0	1.0	1.0	1.0
Weighting Factor - Billings			1.0	2.0	7.0	1.0	0.1	5.0
Number of Bills	CNB	78,216	67,536	8,712	1,548	60	216	144
Number of Connections (Unmetered)	CCON	1,664	-	-	-	1,469	114	81
Total Number of Customer from Approved EDR, Sheet 7-1, Col H excluding connections	CCA	6,446	5,568	726	129	5	18	
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	6,446	5,568	726	129	5	18	
Line Transformer Customer Base	CCLT	6,419	5,568	726	102	5	18	
Secondary Customer Base	CCS	6,419	5,568	726	102	5	18	
Weighted - Services	CWCS	9,704	5,568	1,452	1,020	1,469	114	81
Weighted Meter -Capital	CWMC	553,615	303,970	93,365	156,280	-	-	-
Weighted Meter Reading	CWMR	110,208	74,366	18,186	17,068	588	-	-
Weighted Bills	CWNB	96,598	67,536	17,424	10,836	60	22	720
Data Mismatch Analysis								
Revenue with 30 year weather normalized kWh		2,763,134	1,598,808	444,741	685,446	19,028	1,729	13,381

Weather Normalized Data from Hydro

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	242,507,104	**49,978,185**	28,403,343	162,088,407	1,152,865	29,734	854,570
2006 EDR Distribution Loss Factor		**1.0651**	1.0651	1.0651	1.0651	1.0651	1.0651

Bad Debt Data from EDR 2006

Sheet ADJ5 rows 26 - 32, column E	-	-	-				
Sheet ADJ5 rows 26 - 32, column F	28,281	- 22	28,303				
Sheet ADJ5 rows 26 - 32, column G	31,942	31,024	918				
Three-year average	**20,074**	**10,334**	**9,740**	**-**	**-**	**-**	**-**

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Sheet O1 Revenue to Cost Summary Worksheet - Second Run

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Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
crev	Distribution Revenue (sale)	$2,790,897	$1,582,535	$432,779	$736,272	$22,871	$2,188	$14,252
mi	Miscellaneous Revenue (mi)	$229,656	$119,473	$40,877	$62,568	$5,233	$416	$1,089
	Total Revenue	$3,020,553	**$1,702,008**	**$473,656**	**$798,840**	**$28,104**	**$2,604**	**$15,341**
	Expenses							
di	Distribution Costs (di)	$613,172	$254,879	$94,751	$225,286	$32,844	$2,540	$2,872
cu	Customer Related Costs (cu)	$539,592	$356,271	$99,338	$70,398	$10,438	$797	$2,351
ad	General and Administration (ad)	$717,768	$373,588	$119,657	$192,082	$27,127	$2,091	$3,224
dep	Depreciation and Amortization (dep)	$435,963	$182,632	$67,731	$162,294	$19,947	$1,540	$1,820
INPUT	PILs (INPUT)	$168,350	$64,313	$24,061	$71,835	$6,946	$533	$661
INT	Interest	$189,553	$72,413	$27,091	$80,883	$7,821	$600	$744
	Total Expenses	$2,664,398	**$1,304,096**	**$432,629**	**$802,778**	**$105,123**	**$8,101**	**$11,671**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$356,153	$136,058	$50,902	$151,971	$14,695	$1,128	$1,398
	Revenue Requirement (includes NI)	$3,020,551	$1,440,155	$483,531	$954,749	$119,818	$9,229	$13,070
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$11,406,434	$4,517,094	$1,668,310	$4,630,475	$505,853	$39,031	$45,671
gp	General Plant - Gross	$1,962,098	$750,626	$280,685	$835,627	$81,215	$6,235	$7,711
accum dep	Accumulated Depreciation	($7,904,045)	($3,177,210)	($1,167,282)	($3,138,863)	($360,882)	($27,901)	($31,907)
co	Capital Contribution	($212,621)	($83,984)	($31,062)	($86,556)	($9,440)	($728)	($850)
	Total Net Plant	$5,251,867	**$2,006,527**	**$750,651**	**$2,240,683**	**$216,746**	**$16,637**	**$20,623**
	Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$15,757,503	$3,074,409	$1,717,720	$10,820,351	$86,118	$2,338	$56,567
	OM&A Expenses	$1,870,532	$984,737	$313,746	$487,766	$70,409	$5,427	$8,446
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$17,628,035*	***$4,059,147***	***$2,031,466***	***$11,308,117***	***$156,527***	***$7,765***	***$65,013***
	Working Capital	$2,644,205	**$608,872**	**$304,720**	**$1,696,218**	**$23,479**	**$1,165**	**$9,752**
	Total Rate Base	$7,896,072	**$2,615,399**	**$1,055,371**	**$3,936,900**	**$240,225**	**$17,802**	**$30,375**
		Rate Base Input equals Output						
	Equity Component of Rate Base	$3,948,036	**$1,307,699**	**$527,686**	**$1,968,450**	**$120,112**	**$8,901**	**$15,188**
	Net Income on Allocated Assets	$356,155	**$397,912**	**$41,027**	**($3,938)**	**($77,019)**	**($5,497)**	**$3,670**
	Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	$356,155	**$397,912**	**$41,027**	**($3,938)**	**($77,019)**	**($5,497)**	**$3,670**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	118.18%	97.96%	83.67%	23.46%	28.21%	117.38%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$2	$261,853	($9,875)	($155,909)	($91,715)	($6,625)	$2,272
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.02%	30.43%	7.77%	-0.20%	-64.12%	-61.76%	24.16%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$5.55	$10.00	$57.99	$0.59	$0.58	$2.29
Customer Unit Cost per month - Directly Related	$8.73	$16.11	$89.26	$0.96	$0.94	$3.78
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.13	$22.64	$91.76	$6.75	$6.72	$7.84
Fixed Charge per approved 2006 EDR	$11.27	$12.50	$13.93	$0.95	$1.45	$12.24

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
General Plant - Gross Assets	$1,962,098	$750,626	$280,685	$835,627	$81,215	$6,235	$7,711
General Plant - Accumulated Depreciation	($1,599,174)	($611,785)	($228,767)	($681,063)	($66,193)	($5,082)	($6,284)
General Plant - Net Fixed Assets	$362,924	$138,841	$51,918	$154,564	$15,022	$1,153	$1,426
General Plant - Depreciation	$90,291	$34,542	$12,916	$38,454	$3,737	$287	$355
Total Net Fixed Assets Excluding General Plant	$4,888,943	$1,867,685	$698,734	$2,086,119	$201,724	$15,484	$19,197
Total Administration and General Expense	$717,768	$373,588	$119,657	$192,082	$27,127	$2,091	$3,224
Total O&M	$1,152,764	$611,149	$194,089	$295,684	$43,282	$3,337	$5,223

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$849,424	$466,388	$143,252	$239,784	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($513,533)	($281,962)	($86,605)	($144,965)	$0	$0	$0
	Meter Net Fixed Assets	**$335,891**	**$184,425**	**$56,647**	**$94,819**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($16,205)	($11,330)	($2,923)	($1,818)	($10)	($4)	($121)
4220	Other Electric Revenues	($354)	($135)	($51)	($151)	($15)	($1)	($1)
4225	Late Payment Charges	($24,085)	($15,583)	($8,502)	$0	$0	$0	$0
	Sub-total	*($40,644)*	*($27,048)*	*($11,475)*	*($1,969)*	*($25)*	*($5)*	*($122)*
	Operation							
5065	Meter Expense	$7,378	$4,051	$1,244	$2,083	$0	$0	$0
5070	Customer Premises - Operation Labour	$52,627	$36,234	$4,724	$839	$9,560	$742	$527
5075	Customer Premises - Materials and Expenses	$21	$14	$2	$0	$4	$0	$0
	Sub-total	*$60,025*	*$40,299*	*$5,971*	*$2,923*	*$9,563*	*$742*	*$527*
	Maintenance							
5175	Maintenance of Meters	$67,467	$37,044	$11,378	$19,045	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$135,498	$91,431	$22,359	$20,985	$723	$0	$0
5315	Customer Billing	$146,900	$102,705	$26,497	$16,479	$91	$33	$1,095
5320	Collecting	$97,294	$68,023	$17,550	$10,914	$60	$22	$725
5325	Collecting- Cash Over and Short	($17)	($12)	($3)	($2)	($0)	($0)	($0)
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$379,675	$262,147	$66,403	$48,376	$875	$55	$1,820
	Total Operation, Maintenance and Billing	$507,167	$339,490	$83,752	$70,344	$10,438	$797	$2,347
	Amortization Expense - Meters	$28,700	$15,758	$4,840	$8,102	$0	$0	$0
	Allocated PILs	$10,767	$5,911	$1,816	$3,040	$0	$0	$0
	Allocated Debt Return	$12,123	$6,656	$2,044	$3,423	$0	$0	$0
	Allocated Equity Return	$22,778	$12,506	$3,841	$6,431	$0	$0	$0
	Total	**$540,891**	**$353,272**	**$84,818**	**$89,370**	**$10,413**	**$792**	**$2,225**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$849,424	$466,388	$143,252	$239,784	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($513,533)	($281,962)	($86,605)	($144,965)	$0	$0	$0
	Meter Net Fixed Assets	$335,891	$184,425	$56,647	$94,819	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$24,944	$13,710	$4,209	$7,025	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$360,835	$198,135	$60,856	$101,844	$0	$0	$0
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($16,205)	($11,330)	($2,923)	($1,818)	($10)	($4)	($121)
4220	Other Electric Revenues	($354)	($135)	($51)	($151)	($15)	($1)	($1)
4225	Late Payment Charges	($24,085)	($15,583)	($8,502)	$0	$0	$0	$0
	Sub-total	*($40,644)*	*($27,048)*	*($11,475)*	*($1,969)*	*($25)*	*($5)*	*($122)*
	Operation							
5065	Meter Expense	$7,378	$4,051	$1,244	$2,083	$0	$0	$0
5070	Customer Premises - Operation Labour	$52,627	$36,234	$4,724	$839	$9,560	$742	$527
5075	Customer Premises - Materials and Expenses	$21	$14	$2	$0	$4	$0	$0
	Sub-total	*$60,025*	*$40,299*	*$5,971*	*$2,923*	*$9,563*	*$742*	*$527*
	Maintenance							
5175	Maintenance of Meters	$67,467	$37,044	$11,378	$19,045	$0	$0	$0
	Billing and Collection							
	Sub-total	*$379,675*	*$262,147*	*$66,403*	*$48,376*	*$875*	*$55*	*$1,820*
	Total Operation, Maintenance and Billing	$507,167	$339,490	$83,752	$70,344	$10,438	$797	$2,347
	Amortization Expense - Meters	$28,700	$15,758	$4,840	$8,102	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$6,206*	*$3,411*	*$1,047*	*$1,748*	*$0*	*$0*	*$0*
	Admin and General	$313,346	$207,526	$51,634	$45,697	$6,542	$499	$1,449
	Allocated PILs	$11,566	$6,351	$1,951	$3,265	$0	$0	$0
	Allocated Debt Return	$13,023	$7,151	$2,196	$3,676	$0	$0	$0
	Allocated Equity Return	$24,469	$13,435	$4,127	$6,907	$0	$0	$0
	Total	**$863,834**	**$566,073**	**$138,071**	**$137,770**	**$16,955**	**$1,291**	**$3,674**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

			1	2	3	7	8	9
USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	Sub-total	*$3,676,951*	*$2,401,998*	*$404,239*	*$302,030*	*$501,856*	*$38,944*	*$27,884*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($2,207,602)	($1,436,353)	($239,423)	($188,185)	($303,297)	($23,529)	($16,814)
	Customer Related Net Fixed Assets	$1,469,350	$965,644	$164,815	$113,846	$198,559	$15,415	$11,070
	Allocated General Plant Net Fixed Assets	$109,223	$71,785	$12,246	$8,435	$14,787	$1,148	$822
	Customer Related NFA Including General Plant	$1,578,573	$1,037,429	$177,062	$122,281	$213,346	$16,563	$11,892
	Misc Revenue							
	Sub-total	*($104,398)*	*($71,622)*	*($22,975)*	*($9,120)*	*($64)*	*($19)*	*($597)*
	Operating and Maintenance							
	Sub-total	*$308,167*	*$201,431*	*$33,619*	*$25,254*	*$42,252*	*$3,279*	*$2,333*
	Billing and Collection							
	Sub-total	*$412,100*	*$278,928*	*$81,989*	*$48,430*	*$875*	*$55*	*$1,824*
	Sub Total Operating, Maintenance and Biling	*$720,267*	*$480,358*	*$115,608*	*$73,683*	*$43,127*	*$3,333*	*$4,157*
	Amortization Expense - Customer Related	$125,053	$80,421	$14,207	$12,131	$16,130	$1,251	$914
	Amortization Expense - General Plant assigned to Meters	$27,173	$17,859	$3,047	$2,099	$3,679	$286	$205
	Admin and General	$444,460	$293,637	$71,273	$47,866	$27,029	$2,088	$2,566
	Allocated PILs	$50,597	$33,252	$5,675	$3,920	$6,837	$531	$381
	Allocated Debt Return	$56,969	$37,440	$6,390	$4,414	$7,699	$598	$429
	Allocated Equity Return	$107,040	$70,346	$12,007	$8,294	$14,465	$1,123	$806
	PLCC Adjustment for Line Transformer	$44,102	$37,896	$4,950	$703	$0	$0	$552
	PLCC Adjustment for Primary Costs	$28,202	$24,136	$3,150	$565	$0	$0	$351
	PLCC Adjustment for Secondary Costs	$22,608	$19,709	$2,189	$375	$0	$0	$335
	Total	$1,332,251	**$859,950**	**$194,944**	**$141,644**	**$118,901**	**$9,191**	**$7,621**

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 849,424	$ 466,388	$ 143,252	$ 239,784	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (513,533)	$ (281,962)	$ (86,605)	$ (144,965)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 335,891	$ 184,425	$ 56,647	$ 94,819	$ -	$ -	$ -
Misc Revenue							
Sub-total	$ (40,644)	$ (27,048)	$ (11,475)	$ (1,969)	$ (25)	$ (5)	$ (122)
Operation							
Sub-total	$ 60,025	$ 40,299	$ 5,971	$ 2,923	$ 9,563	$ 742	$ 527
Maintenance							
1860	$ 67,467	$ 37,044	$ 11,378	$ 19,045	$ -	$ -	$ -
Billing and Collection							
Sub-total	$ 379,675	$ 262,147	$ 66,403	$ 48,376	$ 875	$ 55	$ 1,820
Total Operation, Maintenance and Billing	$ 507,167	$ 339,490	$ 83,752	$ 70,344	$ 10,438	$ 797	$ 2,347
Amortization Expense - Meters	$ 28,700	$ 15,758	$ 4,840	$ 8,102	$ -	$ -	$ -
Allocated PILs	$ 10,767	$ 5,911	$ 1,816	$ 3,040	$ -	$ -	$ -
Allocated Debt Return	$ 12,123	$ 6,656	$ 2,044	$ 3,423	$ -	$ -	$ -
Allocated Equity Return	$ 22,778	$ 12,506	$ 3,841	$ 6,431	$ -	$ -	$ -
Total	**$ 540,891**	**$ 353,272**	**$ 84,818**	**$ 89,370**	**$ 10,413**	**$ 792**	**$ 2,225**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 849,424	$ 466,388	$ 143,252	$ 239,784	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (513,533)	$ (281,962)	$ (86,605)	$ (144,965)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 335,891	$ 184,425	$ 56,647	$ 94,819	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 24,944	$ 13,710	$ 4,209	$ 7,025	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 360,835	$ 198,135	$ 60,856	$ 101,844	$ -	$ -	$ -
Misc Revenue							
Sub-total	*$ (40,644)*	*$ (27,048)*	*$ (11,475)*	*$ (1,969)*	*$ (25)*	*$ (5)*	*$ (122)*
Operation							
Sub-total	*$ 60,025*	*$ 40,299*	*$ 5,971*	*$ 2,923*	*$ 9,563*	*$ 742*	*$ 527*
Maintenance							
1860	$ 67,467	$ 37,044	$ 11,378	$ 19,045	$ -	$ -	$ -
Billing and Collection							
Sub-total	*$ 379,675*	*$ 262,147*	*$ 66,403*	*$ 48,376*	*$ 875*	*$ 55*	*$ 1,820*
Total Operation, Maintenance and Billing	$ 507,167	$ 339,490	$ 83,752	$ 70,344	$ 10,438	$ 797	$ 2,347
Amortization Expense - Meters	$ 28,700	$ 15,758	$ 4,840	$ 8,102	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 6,206	$ 3,411	$ 1,047	$ 1,748	$ -	$ -	$ -
Admin and General	$ 313,346	$ 207,526	$ 51,634	$ 45,697	$ 6,542	$ 499	$ 1,449
Allocated PILs	$ 11,566	$ 6,351	$ 1,951	$ 3,265	$ -	$ -	$ -
Allocated Debt Return	$ 13,023	$ 7,151	$ 2,196	$ 3,676	$ -	$ -	$ -
Allocated Equity Return	$ 24,469	$ 13,435	$ 4,127	$ 6,907	$ -	$ -	$ -
Total	**$ 863,834**	**$ 566,073**	**$ 138,071**	**$ 137,770**	**$ 16,955**	**$ 1,291**	**$ 3,674**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	Sub-total	*$ 3,676,951*	*$ 2,401,998*	*$ 404,239*	*$ 302,030*	*$ 501,856*	*$ 38,944*	*$ 27,884*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (2,207,602)	$ (1,436,353)	$ (239,423)	$ (188,185)	$ (303,297)	$ (23,529)	$ (16,814)
	Customer Related Net Fixed Assets	$ 1,469,350	$ 965,644	$ 164,815	$ 113,846	$ 198,559	$ 15,415	$ 11,070
	Allocated General Plant Net Fixed Assets	$ 109,223	$ 71,785	$ 12,246	$ 8,435	$ 14,787	$ 1,148	$ 822
	Customer Related NFA Including General Plant	$ 1,578,573	$ 1,037,429	$ 177,062	$ 122,281	$ 213,346	$ 16,563	$ 11,892
	Misc Revenue							
	Sub-total	*$ (104,398)*	*$ (71,622)*	*$ (22,975)*	*$ (9,120)*	*$ (64)*	*$ (19)*	*$ (597)*
	Operating and Maintenance							
	Sub-total	*$ 308,167*	*$ 201,431*	*$ 33,619*	*$ 25,254*	*$ 42,252*	*$ 3,279*	*$ 2,333*
	Billing and Collection							
	Sub-total	*$ 412,100*	*$ 278,928*	*$ 81,989*	*$ 48,430*	*$ 875*	*$ 55*	*$ 1,824*
	Sub Total Operating, Maintenance and Biling	*$ 720,267*	*$ 480,358*	*$ 115,608*	*$ 73,683*	*$ 43,127*	*$ 3,333*	*$ 4,157*
	Amortization Expense - Customer Related	$ 125,053	$ 80,421	$ 14,207	$ 12,131	$ 16,130	$ 1,251	$ 914
	Amortization Expense - General Plant assigned to Meters	$ 27,173	$ 17,859	$ 3,047	$ 2,099	$ 3,679	$ 286	$ 205
	Admin and General	$ 444,460	$ 293,637	$ 71,273	$ 47,866	$ 27,029	$ 2,088	$ 2,566
	Allocated PILs	$ 50,597	$ 33,252	$ 5,675	$ 3,920	$ 6,837	$ 531	$ 381
	Allocated Debt Return	$ 56,969	$ 37,440	$ 6,390	$ 4,414	$ 7,699	$ 598	$ 429
	Allocated Equity Return	$ 107,040	$ 70,346	$ 12,007	$ 8,294	$ 14,465	$ 1,123	$ 806
	PLCC Adjustment for Line Transformer	$ 44,102	$ 37,896	$ 4,950	$ 703	$ -	$ -	$ 552
	PLCC Adjustment for Primary Costs	$ 28,202	$ 24,136	$ 3,150	$ 565	$ -	$ -	$ 351
	PLCC Adjustment for Secondary Costs	$ 22,608	$ 19,709	$ 2,189	$ 375	$ -	$ -	$ 335
	Total	**$ 1,332,251**	**$ 859,950**	**$ 194,944**	**$ 141,644**	**$ 118,901**	**$ 9,191**	**$ 7,621**

Summary of Results and Proposed Changes

Summary of Results

Revenue to Cost Ratios

The results of a cost allocation are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage shows the rate classifications that are being subsidized and those that are over contributing. A percentage of less than 100% means the rate classification is under collecting and is being subsidized by other classes. A percentage of greater than 100% indicates the rate classification is over collecting the cost assigned to the classification and is subsidizing other classes.

The following outlines the revenue to cost ratios for Run 2. The results for Run 1 are similar. In Run 1, the USL rate classification is combined with the General Service < 50 kW rate classification. As a result, the cost to revenue ratio in Run 1 for General Service < 50 kW customers is 98.62% and there is no ratio for USL. All other ratios in Run 1 are essentially the same as Run 2.

Table 65 Revenue to Cost Ratios

Rate Classification	Revenue to Cost Ratio	($Being Subsidized)/ $Over Contributing
Residential	118.18%	$261,852
General Service <50 kW	97.96%	($9,875)
General Service >50 kW	83.67%	($155,909)
Street Lights	23.46%	($91,715)
Sentinel Lights	28.21%	($6,625)
USL	117.38%	$2,272
Total	100.0%	0

The above results suggests the Residential and USL rate classifications are subsidizing the General Service >50 kW, street lights and sentinel light rate classifications. With regard to

Street Lights and Sentinel Lights, it is assumed in the cost allocation study that a street light or sentinel light connection is equivalent to a customer. This appeared to be reasonable because in the case of other rate classifications each connection is essentially a customer. This means the customer costs allocated to street lights and sentinel lights are based on 1469 and 114 connections, respectively which is the biggest driver that is causing the results for these two classes.

Monthly Fixed Charge Comparison

The Model produces customer unit costs per month for each rate classification. To assist with reviewing the range of current fixed monthly service charges, the Model generates three scenarios of reasonable cost-based customer unit costs for each rate classification. These unit costs are determined by the Model and compared to the current approved monthly service charge.

Scenario 1: Avoided Costs (Minimum Charge)

With a strict “avoided cost” approach, only meter related costs, billing and collection costs are included. This approach has the advantage of focusing on the immediate costs of an additional customer. But no administration and general overhead costs are applied.

Scenario 2: Directly Related Customer Costs

The directly related customer costs are those costs included in the avoided cost version but an allocation of administration and general overhead costs is included.

Scenario 3: Minimum System Approach

The minimum system approach assumes that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. For the purposes of this filing the minimum load requirement is assumed to be 400 watts per customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the distributor. Once determined for each plant account, the minimum size distribution system is classified as customer-related costs and then used to define the monthly unit customer cost.

There are various approaches to define the minimum system. Moreover, judgment is required to address various implementation details with this methodology. The OEB cost allocation project did not seek to develop a common minimum system methodology for use by the Ontario electricity distribution sector. Instead, the results of numerous past Ontario minimum system studies were examined and approved for use in the Model.

The minimum system results are applied to the following accounts:

- Line Transformers (Account 1850)
- "Distribution" which includes poles and conductors, and is defined as Accounts 1830 -1845
- Related O&M accounts.

The density of the distributor (i.e. customers/route kilometer of line) is the major factor that determines the percentage of the above costs which are included in the customer costs. The density of MPUC is 63 customers/km. This means MPUC is classified as a high density distributor. As a result, 35% of MPUC's distribution costs (i.e. lines, poles and line transformers) are defined to be customer related cost.

The monthly customer unit cost under the minimum system approach includes the directly related customer costs plus 100% of distribution costs with any administration and general overhead associated with the distribution costs. The following outlines the monthly fixed cost comparison:

Table 66 Comparison of Monthly Fixed Cost

Rate Classification	Approved Fixed Charge	Minimum System Fixed Charge	Directly Related Fixed Charge	Avoided Cost Fixed Charge
Residential	$11.11	$13.13	$8.73	$5.55
General Service <50 kW	$12.35	$22.64	$16.11	$10.00
General Service >50 kW	$13.79	$91.76	$89.26	$57.99
Street Lights	$0.96	$6.75	$0.96	$0.59
Sentinel Lights	$1.46	$6.72	$0.94	$0.58
USL	$12.35	$7.84	$3.78	$2.29

All MPUC Approved Fixed Charges are greater than the Avoided Cost Fixed Charge except for General Service >50kW. MPUC is proposing that the General Service >50kW customer class Fixed Charge be brought up to the Avoided Cost Fixed Charge which will gradually increase the charge to avoid dramatic increases future cost of service applications.

Report of the Board on Application of the Cost Allocation for Electricity Distributors

In early 2007, Local Distribution Corporations were required to file cost allocation studies based on the Ontario Energy Board's "Cost Allocation Review: Board Directions on Cost Allocation Methodology for Electricity Distributors EB-2005-0317, September 29, 2006" and the Cost Allocation Model. MPUC complied with the above requirement and filed its study on February 15, 2007.

On November 28, 2007 the Board issued a report "Application of Cost Allocation for Electricity Distributors" The report addressed a number of issues, most significantly the relationship between the class revenue and the class total allocated costs (the "revenue-to-cost ratio"). This Report also discussed the treatment of the Monthly Service Charge, metering credits for the unmetered scattered load class, transformer credits for customer-owned transformers, and charges for the provision of standby power for customers with load displacement generation.

MPUC would submit, as other utilities have pointed out, that the results are valuable in informing LDCs on cost allocation and rate design in their rebasing exercises over the next three years. At page 6 of the report, the Board states the following;

> **"Managing the movement of rates closer to allocated costs:**
> A principle of rate making is that rate stability in most instances is desirable. Rates should not be constructed in a manner that leads to subsequent counter directional changes. The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process.
>
> Another principle of rate making is the avoidance of rate shock. Proposed rate changes should consider the ability of consumers to react to their new costs. In aligning rate levels closer to costs, reducing a high revenue-to-cost ratio for any one class requires an offsetting increase to one or more other classes. Such realignments could result in large rate increases, particularly when combined with other plans that affect the distributor's

> revenue requirement.
>
> The Board expects to address these concerns as and when they arise in the context of individual rate applications. Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one."

In the Board report the following class specific revenue to cost ratio ranges have been established. This range is compared with the MPUC revenue cost ratio from the MPUC informational filing.

Table 67 Comparison of Revenue to Costs Ratios

Class	Established Range	MPUC Revenue to Cost Ratios
Residential	85% to 115%	118%
GS < 50 kW	80% to 120%	98%
GS > 50 kW	80% to 180%	84%
Street Lighting	70% to 120%	23%
Sentinel Lights	70% to 120%	28%
USL	80% to 120%	117%

In MPUC's view the revenue to cost ratio information resulting from the recent cost allocation information filing can be used to start addressing the issue of cross subsidization in this rate application. MPUC expects the revenue to cost results shown above would not be significantly different if the cost allocation study was redone using the data in this application. Class volumes have not changed significantly from the informational filing. In addition, no large costs are directly allocated to one specific class of customer. At this time, MPUC plans to complete another cost allocation study during the next rebasing rate application to review and possibly adjust the revenue to cost ratios at that time. As a result. MPUC is proposing to move the revenue to cost ratios in this application to the following levels

Table 68 Proposed Revenue to Cost Ratios

Class	Established Range	Proposed MPUC Revenue to Cost Ratios
Residential	85% to 115%	107%
GS < 50 kW	80% to 120%	98%
GS > 50 kW	80% to 180%	98%
Street Lighting	70% to 120%	49%
Sentinel Lights	70% to 120%	49%
USL	80% to 120%	100%

These proposed revenue to cost ratios will result in the following proportion of revenue by rate class.

Table 69 Proportion of Revenue by Rate Class

Class	Proportion of Revenue %	Proportion of Revenue $
Residential	50.56%	$1,811,424
GS < 50 kW	15.62%	$559.442
GS > 50 kW	31.23%	$1,118,884
Street Lighting	2.01%	$72,013
Sentinel Lights	0.16%	$5,553
USL	0,43%	$15,406
Total	100.00%	$3,582,721

EXHIBIT 9 - RATE DESIGN

Rate Design

Rate Design Overview

This exhibit documents the calculation of MPUC's proposed distribution rates by rate class for the 2009 test year, based on rate design as proposed in this Exhibit.

Determination of Service Revenue Requirement

MPUC has determined its total 2009 service revenue requirement to be $3,813,851. The total revenue offset in the amount of $231,131 reduces MPUC's total service revenue requirement to a base revenue requirement to $3,582,721, which is used to determine the proposed distribution rates. The base revenue requirement is derived from MPUC's 2009 capital and operating forecasts, weather normalized usage, forecasted customer counts, and MPUC's regulated return on rate base.

Table 70 Calculation of Base Revenue Requirement

OM&A Expenses	2,093,100
Amortization Expenses	735,424
Total Distribution Expenses	2,828,524
Regulated Return On Capital	780,334
PILs (with gross-up)	204,993
Service Revenue Requirement	3,813,852
Less: Revenue Offsets	(231,131)
Base Revenue Requirement	**3,582,721**

The outstanding base revenue requirement is allocated to the various rate classes using the following proposed apportionment of revenue as outlined in Exhibit 8 – Cost Allocation.

Table 71 Proposed Apportionment of Revenue to Rate Classes

Rate Classification	Proposed Proportion of Revenue
Residential	50.56%
General Service Less Than 50 kW	15.62%
General Service Greater Than 50 kW	31.23%
Street Lights	2.01%
Sentinel Lights	0.16%
Unmetered Scattered Load	0.43%
Total	100.0%

The following table outlines the results of this allocation.

Table 72 Allocation of Outstanding Base Revenue Requirement

Rate Classification	**Proposed Revenue**
Residential	$1,811,424
General Service Less Than 50 kW	$ 559,442
General Service Greater Than 50 kW	$1,118,884
Street Lights	$ 72,013
Sentinel Lights	$ 5,553
Unmetered Scattered Load	$ 15,406
Total	$3,582,721

Determination of Monthly Fixed Charges:

MPUC's current OEB-approved monthly fixed charges based on its 2008 IRM application by customer class are summarized in the table below.

Table 73 Current Monthly Fixed Charges

Rate Class	**Current Monthly Fixed Charge**
Residential	$11.11
General Service Less Than 50 kW	$12.35
General Service Greater Than 50 kW	$13.79
Street Lights	$0.96
Sentinel Lights	$1.46
Unmetered Scattered Load	$12.35

Table 74 (Comparison of Existing and Resulting Rate for the Variable Charge) shown on the following page outlines the splits between fixed and variable distribution revenue at Existing Rates (1); at Cost Allocation – Minimum Fixed Rate (2); at Cost Allocation – Maximum Fixed Rate (2); Existing Fixed/Variable Split based on 2009 Revenue Requirement (3); and the proposed Fixed Variable Splits in this Rate Application. The table also sets out the Resulting Rate for the Variable Charge in comparison to the Existing Usage Rate.

Table 74 Comparison of Existing and Resulting Rate for the Variable Charge

Customer Class Name	Existing Rates			Cost Allocation - Minimum Fixed Rate (2)			Cost Allocation - Maximun Fixed Rate (2)		
	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %	Rate	Fixed %	Variabl e %
Residential	$11.11	44.87%	55.13%	$5.55	21.08%	78.92%	$13.13	49.88%	50.12%
General Service <50 kW	$12.35	21.82%	78.18%	$10.00	14.46%	85.54%	$22.64	32.74%	67.26%
General Service >50 Kw	$13.79	2.17%	97.83%	$57.99	4.87%	95.13%	$91.76	7.70%	92.30%
Street Lighting	$0.96	71.33%	28.67%	$0.59	15.08%	84.92%	$6.75	172.49%	-72.49%
Sentinel Lighting	$1.46	76.94%	23.06%	$0.58	2.75%	97.25%	$6.72	31.83%	68.17%
Unmetered Scattered Load	$12.35	19.83%	80.17%	$2.29	2.03%	97.97%	$12.35	10.94%	89.06%

Customer Class Name	Existing Fixed/Variable Split			Rate Application			Resulting Usage		Existing
	Rate	Fixed %	Variable %	Rate	Fixed %	Variable %	Rate	per	Usage Rate
Residential	$11.81	44.87%	55.13%	$11.81	44.86%	55.14%	$0.0211	kWh	$0.0198
General Service <50 kW	$15.09	21.82%	78.18%	$15.09	21.82%	78.18%	$0.0171	kWh	$0.0140
General Service >50 Kw	$25.79	2.17%	97.83%	$57.99	4.87%	95.13%	$4.2097	kW	$2.3148
Street Lighting	$2.79	71.33%	28.67%	$2.79	71.29%	28.71%	$6.9080	kW	$2.3727
Sentinel Lighting	$16.25	76.94%	23.06%	$16.25	76.96%	23.04%	$29.1889	kW	$2.6254
Unmetered Scattered Load	$22.38	19.83%	80.17%	$22.38	19.83%	80.17%	$0.0254	kWh	$0.0140

MPUC submits that it is appropriate for 2009 to maintain the same fixed/variable proportions assumed in the current rates for the Residential, General Service <50kW, Street Lights, Sentinel Lights and Unmetered Scattered Load Customer Classes. MPUC is proposing that the General Service >50kW Customer Class Fixed Charge be increased to the Minimum Fixed Rate of $57.99. This will gradually bring this class fixed/variable proportions into the ranges specified by the Board Report. This matter is discussed further below.

In its November 28, 2007 Report on Application of Cost Allocation for Electricity Distributors, referred to in Exhibit 8 above, the OEB addressed a number of “Other Rate Matters”, including the treatment of the fixed rate component (the Monthly Service Charge, or “MSC”) of the bill. At page 12 of the Report, the OEB determined that the floor amount for the MSC should be the avoided costs, as that term is defined in the September 29, 2006 report of the OEB entitled “Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors”. MPUC’s MSCs exceed that floor amount except for General Service >50kW. MPUC’s existing rate is $13.79 vs. the Minimum Fixed Rate (Avoided Cost) of $57.99. With respect to the upper bound for the MSC, the OEB considered it to be inappropriate to make changes to the MSC ceiling at this time, given the number of issues that remain to be examined within the scope of the OEB's Rate Review proceeding (EB-2008-0031). The OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC; and that distributors that are currently above that value are not required to make changes to their current MSC to bring it to or below that level at this time.

MPUC confirms that it is making one change to the current fixed and variable proportions of its rates for the General Service >50kW Class by increasing the fixed portion to $57.99. Any changes in Monthly Service Charge in the Residential, General Service <50kW, Street Lights, Sentinel Lights and Unmetered Scattered Load are due solely to changes in the total base revenue requirement attributable to each customer class.

Proposed Volumetric Charges:

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2009 Test Year usage, kWh or kW, as the class charge determinant.

The following Table provides MPUC's calculations of its proposed variable distribution charges for the 2009 Test Year assuming the same fixed/variable split used in designing the current approved rates, and includes the proposed adjustment for the Transformer Allowance as discussed below.

Table 75 Variable Distribution Charge Calculation

Customer Class	Gross Revenue Requirement	Variable Revenue Proportion	2009 Test Volumetric Billing Determinant		Proposed Volumetric Distribution Charge
Residential	$1,901,008	55.13%	49,791,737	kWh	$0.0211
General Service Less Than 50 kW	$ 604,986	78.18%	27,650,878	kWh	$0.0171
General Service Greater Than 50 kW	$1,472,170	95.13%	332,681	kW	$4.2097
Street Lights	$ 73,446	28.67%	3,052	kW	$6.9080
Sentinel Lights	$ 5,574	23.06%	44	kW	$29.1889
Unmetered Scattered Load	$ 16,252	80.17%	513,550	KWh	$0.0254
Total	$4,073,436				

Proposed Adjustment to Transformer Allowance:

Currently, MPUC provides a Transformer Allowance to those customers that own their transformation facilities. MPUC proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of Transformer Allowance expected to be provided to those General Service Greater than 50 kW customers that own their transformers has been included in the General Service Greater Than 50 kW volumetric charge. This means the General Service Greater than 50 kW volumetric charge has been increased by $0.4545 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service Greater Than 50 kW rate class. Once the Transformer Allowance is applied to this charge the resulting revenue will recover the full base revenue requirement for the General Service Greater than 50 kW rate class.

Recovery of Low Voltage Costs:

Consistent with the approach in the Board's 2006 EDR model, LV costs of $339,515 have been allocated to each rate class based on the proportion of retail transmission connection revenue collected from each class. This calculation is outlined in the following table:

Table 76 Allocation of LV Costs

Rate Classification	Retail Transmission Connection Revenue	Allocation Percentages	Allocated LV
Residential	$376,536	26.4%	$89,584
General Service Less Than 50 kW	$191,431	13.4%	$45,545
General Service 50 to 4,999 kW	$849,401	59.5%	$202,086
Street Lights	$6,024	0.4%	$1,433
Sentinel Lights	$89	0.0%	$21
Unmetered Scattered Load	$3,555	0.2%	$846
Total	**$1,427,036**	**100.0%**	**$339,515**

These proposed LV costs by rate class are then divided by the projected volumes and this produces the proposed adjustments to the distribution volumetric charges set out in the table below:

Table 77 LV-Related Adjustments to Volumetric Charges

Rate Classification	LV Adjustment ($ per kWh)	LV Adjustment ($ per kW)
Residential	0.0018	-
General Service Less Than 50 kW	0.0016	-
General Service 50 to 4,999 kW	-	0.6074
Street Lights	-	0.4696
Sentinel Lights	-	0.4794
Unmetered Scattered Load	0.0016	-

Proposed Distribution Rates:

The following table sets out MPUC's proposed 2009 electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance and the smart meter rate adder:

Table 78 Proposed 2009 Electricity Distribution Rates

Customer Class	Customer	Connection	kWh	kW
Residential	$11.81		$0.0211	
General Service Less Than 50 kW	$15.09		$0.0171	
General Service Greater than 50kW	$57.99			$4.2097
Street Lights		$2.79		$6.9080
Sentinel Lights		$16.25		$29.1889
Unmetered Scattered Load		$22.38	$0.0254	
Transformer Allowance				($0.60)

Reconciliation of Rate Class Revenue to total Revenue Requirement

The following table outlines the allocation of revenues between rate classes, based on full cost allocation, existing rates and proposed allocations for the 2009 Test Year.

Rate Classification	Fixed Distribution Revenue	Variable Distribution Revenue	Low Voltage	Transformer Allowance	Total Distribution Revenue
Residential	$852,871	$958,553	$89,584		1,901,008
General Service <50kW	$132,007	$ 427,434	$45,545		604,986
General Service >50 kW	$71,676	$1,047,208	$202,086	$151,200	1,472,170
Street Lights	$52,363	$19,650	$1,433		73,446
Sentinel Lights	$4,290	$1,263	$21		5,574
Unmetered Scattered Load	$3,223	$12,183	$846		16,252
Total	**$1,116,429**	**$2,466,291**	**$339,515**	**$151,200**	**4,073,436**

Proposed Smart Meter Rate Rider:

On June 25, 2008 the government filed amendments to three smart metering regulations, namely O. Reg. 427/06 (Smart Meters: Discretionary Metering and Procurement Principles), O. Reg. 426/06 (Smart Meters: Cost Recovery), and O. Reg. 393/07 (Designation of Smart Metering Entity).

Amendments to O. Reg. 427/06 (Smart Meters: Discretionary Metering Activity and Procurement Principles) will:

- Authorize metering activities pursuant to the Request for Proposal (RFP) for Advanced Metering Infrastructure (AMI) – Phase 1 Smart Meter Deployment issued August 14, 2007 by London Hydro Inc. This would include distributors named in the RFP and those distributors that procure AMI pursuant to the parameters established by the RFP;

The CHEC group has been working together to participate in this initiative in accordance with the London Hydro RFP parameters.

At the time of this submission, negotiations are underway with a Fairness Commissioner-designated vendor. It is anticipated that MPUC will be scheduled for full installation of Smart Meters in 2009 in a process expected to take less than two months and require a capital outlay estimated at $ 1.6 million. In accordance with the OEB's Toronto Hydro decision dated May 15, 2008, as shown below, MPUC seeks a rate rider of **$1.00 per customer per month** to fund Smart Meter activities:

- "For certain other distributors who were not named by the government to implement an early smart meter program, upon application for enhanced funding, the Board has increased the adder to $1.00 per month per metered customer to recognize the pending ramping up of expenditures on smart meters for these distributors."

This rate rider would be applicable to the residential, GS <50kW and GS >50kW classes.

Rate Mitigation

MPUC does not propose any rate mitigation in this application. The proposed rate adjustments listed below are considered not to be of such impact to the customer that it requires mitigation. The Revenue Requirement Allocation Table below sets out the Revenue Requirement per customer class in accordance with the Cost Allocation filing and at the 2009 proposed Rates:

Table 79 Revenue Requirement Allocation

Customer Class Name	Base Revenue Requirement %		Base Revenue Requirement $		Revenue to Cost Ratios	
	Cost Allocation	Rate Application	Cost Allocation	Rate Application	Cost Allocation	Rate Application
Residential	47.32%	50.56%	1,695,3852	1,811,424	1.18	1.07
General Service <50kW	15.86%	15.62%	568,243	559,442	0.98	0.98
General Service >50KW	31.97%	31.23%	1,145,308	1,118,884	0.84	0.98
Street Lighting	4.11%	2.01%	147,095	72,013	0.23	0.49
Sentinel Lighting	0.32%	0.16%	11,313	5,553	0.28	0.49
Unmetered Scattered Load	0.43%	0.43%	15,380	15,406	1.17	1.00
TOTAL	**100.0%**	**100.0%**	**3,582,721**	**3,582,721**		

Residential

MPUC does not propose any rate mitigation in this class. As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this class of customer is $3.14 or 2.8%, and therefore does not require mitigation.

General Service < 50 kW

MPUC does not propose any rate mitigation in this class.

The Revenue Requirement Allocation Table above provides a summary of the Revenue Requirement per customer class in accordance with the Cost Allocation filing and the Revenue Requirement which is proposed in this Rate Application

The cost allocation results show that General Service <50 kW customers should be allocated 15.86% or $568,243 of the total revenue requirement, and MPUC is proposing to reduce this percentage to 15.62% or $559,442. In reducing the percentage of total revenue requirement this class customer will align with the revenue to cost ratio of 98% in accordance with the cost allocation study.

As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this class of customer is $10.48 or 5%, and therefore does not require mitigation.

General Service > 50 kW

The cost allocation study results, more particularly set out in the Revenue Requirement Allocation Table above and in Exhibit 8, Tab 1, Schedule 2, show that the General Service > 50kW customers have been subsidized by Residential customers since the unbundling of rates in 1999. Based on these results, the Revenue Requirement Allocation Table referred to above shows that General Service > 50kW customers should be allocated 31.97% or $1,145,308 of the total revenue requirement, and MPUC is proposing to reduce this percentage to 31.23% or $1,118,884. In reducing the percentage of total revenue requirement, this class will be brought into line with the revenue to cost ratio thereby reducing the cross subsidization by Residential class customers. Although this class will continue to be subsidized by Residential customers in the amount of $26,425, if cost allocation is not taken into consideration, this customer class would continue to be subsidized..

As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this customer class is $3,751.86 or 5.8%, and therefore does not require mitigation.

Street Lighting

The cost allocation study results, more particularly set out in the Revenue Requirement Allocation Table above and in Exhibit 8, Tab 1, Schedule 2, show the Street Lighting customer class has been subsidized by Residential customers since the unbundling of rates in 1999. Based on these results, the Revenue Requirement Allocation Table referred to above shows that Street Lighting customers should be allocated 4.11% or $147,095 of the total revenue requirement.

MPUC is proposing to increase the revenue to cost ratio for Street Lighting customers to 49% from the existing 23% thereby increasing the revenue requirement to $72,013. This movement will bring Street Lighting customers half way to the revenue to cost ratio lower floor level of 70%.

As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this customer class is 45.3%. MPUC is not requesting mitigation with this customer class, as movement to the cost allocation floor of 70% is required.

Sentinel Lighting

The cost allocation study results, more particularly set out in the Revenue Requirement Allocation Table above and in Exhibit 8, Tab 1, Schedule 2, show that the Sentinel Lighting customers have been subsidized by Residential customers since the unbundling of rates in 1999. Based on these results, the Revenue Requirement Allocation Table referred to above shows that Sentinel Lighting customers should be allocated 0.32% or $11,313 of the total revenue requirement.

MPUC is proposing to increase the revenue to cost ratio for Sentinel Lighting customers to 0.49% thereby increasing the revenue requirement to $5,553. This movement will bring Street Lighting customers half way to the revenue to cost ratio lower floor level of 70%.

As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this customer class is 23.5%. MPUC is not requesting mitigation with this customer class, as movement to the cost allocation floor or 70% is required.

Unmetered Scattered Load

MPUC is proposing to reduce the revenue to cost ratio for Unmetered Scattered Load (USL) customers from the existing revenue to cost ratio of 117% to 100%.

MPUC does not propose any rate mitigation in this class. As set out in Exhibit 9, Tab 1, Schedule 9, the total bill increase for this class of customer is $187.03 or 12.3% and affects a relatively low number of customers.

Therefore, MPUC considers the proposed rate adjustments not to be of such impacts to the customer classes that it requires rate mitigation.

Existing Rate Classes

Residential

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

General Service Less Than 50 kW

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

General Service 50 to 4,999 kW

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

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

Unmetered Scattered Load

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

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

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

Existing Rate Schedule

The following is MPUC's existing Rate Schedule effective May 1, 2008

Residential

Service Charge	$	11.3700
Distribution Volumetric Rate	$/kWh	0.0198
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0071
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service Less Than 50 kW

Service Charge	$	12.6100
Distribution Volumetric Rate	$/kWh	0.0140
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service 50 to 4,999 kW

Service Charge	$	14.0500
Distribution Volumetric Rate	$/kW	2.3148
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.5532
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Unmetered Scattered Load

Service Charge (per customer)	$	12.3500
Distribution Volumetric Rate	$/kWh	0.0140
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting

Service Charge (per connection)	$	1.4600
Distribution Volumetric Rate	$/kW	2.6254
Retail Transmission Rate – Network Service Rate	$/kW	1.0749
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0150
Wholesale Market Service Rate	$/kWh	0.0052

Sentinel Lighting – Cont'd

Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting

Service Charge (per connection)	$	0.9600
Distribution Volumetric Rate	$/kW	2.3727
Retail Transmission Rate – Network Service Rate	$/kW	1.0694
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges

Customer Administration		
- Notification Charge	$	15.0000
- Account history	$	15.0000
- Returned Cheque charge (plus bank charges)	$	15.0000
- Legal letter charge	$	15.0000
- Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.0000
Non-Payment of Account		
- Late Payment – per month	%	1.5000
- Late Payment - per annum	%	19.5600
- Disconnect/Reconnect at meter – during regular hours	$	65.0000
- Disconnect/Reconnect at meter – after regular hours	$	185.0000
- Disconnect/Reconnect at pole – during regular hours	$	185.0000
- Disconnect/Reconnect at pole – after regular hours	$	415.0000
Specific Charge for Access to Power Poles $/pole/year	$	22.3500
Install/Remove load control device – during regular hours	$	65.0000
Install/Remove load control device – after regular hours	$	185.0000
Temporary service install & remove – overhead – no transformer	$	500.0000
Temporary service install & remove – underground – no transformer	$	300.0000

Allowances

- Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.6000
- Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.0000

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0651
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0545
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Proposed Rate Classes

MPUC is not proposing to make any changes to the existing rate classes.

Proposed Rate Schedule

On the page following this page is a Schedule outlining MPUC's Monthly Rates and Charges for the 2009 Test Year.

Residential

Service Charge	$	12.8100
Distribution Volumetric Rate	$/kWh	0.0211
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0038
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0071
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service <50 kW

Service Charge	$	16.0900
Distribution Volumetric Rate	$/kWh	0.0171
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

General Service >50 Kw

Service Charge	$	58.9900
Distribution Volumetric Rate	$/kW	4.2097
Regulatory Asset Recovery	$/kW	0.1645
Retail Transmission Rate – Network Service Rate	$/kW	1.4180
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.5532
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Street Lighting

Service Charge (per connection)	$	2.7900
Distribution Volumetric Rate	$/kW	6.9080
Regulatory Asset Recovery	$/kW	0.1538
Retail Transmission Rate – Network Service Rate	$/kW	1.0694
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9738
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Sentinel Lighting

Service Charge (per connection)	$	16.2500
Distribution Volumetric Rate	$/kW	29.1889
Regulatory Asset Recovery	$/kW	0.1423
Retail Transmission Rate – Network Service Rate	$/kW	1.0749
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0150
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Unmetered Scattered Load

Service Charge	$	22.3800
Distribution Volumetric Rate	$/kWh	0.0254
Regulatory Asset Recovery	$/kWh	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0034
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0065
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.2500

Specific Service Charges

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	$	30.00
Late Payment - per month	%	1.50
Disconnect/Reconnect at meter – during regular hours	$	65.00
Disconnect/Reconnect at meter – after regular hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install / remove load control device – during regular hours	$	65.00
Install / remove load control device – after regular hours	$	185.00
Temporary service install and remove – overhead – no transformer	$	500.00
Temporary service install and remove – underground – no transformer	$	300.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50

Specific Service Charges – Cont'd

Interval Meter Load Management Tool	$	25.00
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.60
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00

LOSS FACTORS

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0651
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0545

Rate Impacts

This exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are derived using the applicable May 1, 2008 rates and the proposed 2009 distribution rates, (including Rate Rider for the recovery of Regulatory Asset Variance Accounts).

The total bill impacts are calculated for the average customer per residential rate class and for General Service Classes at certain levels of consumption. The rates are assessed on the basis of moving to the proposed distribution rates derived in Exhibit 9, Tab 1, Schedule 8, including the Rate Rider for the recovery of regulatory asset variance accounts derived in Exhibit 5, Tab 1, Schedule 3. The total bill impacts are premised on the distribution rates arising from the new revenue requirements. All other non-distribution charges, are kept unchanged.

On the pages following is a Summary of Bill Impacts for the Residential, GS<50 kWh, GS>50 kWh, Street Lights, Sentinel Lights and Unmetered Scattered Load Classes.

Customer Bill Impacts

RPP rates per sheet Y7

Residential

Volume		RPP	Distribution Charges		Total Bill	
kWh *	kW	Rate Class	$ change	% change	$ change	% change
100		Summer	$1.57	11.8%	$1.61	7.6%
250		Summer	$1.77	10.8%	$1.87	5.2%
500		Summer	$2.09	9.8%	$2.29	3.8%
600		Summer	$2.22	9.5%	$2.46	3.5%
750		Summer	$2.42	9.2%	$2.72	3.1%
1,000		Summer	$2.74	8.8%	$3.14	2.8%
1,500		Summer	$3.39	8.3%	$3.99	2.4%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**

100 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	100	$0.0198	$1.98	100	$0.0211	$2.11	$0.13	6.6%
Sub-Total (Distribution)				**$13.35**			**$14.92**	**$1.57**	**11.8%**
Deferral/Variance	kWh	100			100	$0.0004	$0.04	$0.04	
Electricity (Commodity)	kWh	107	RPP-Summer	$5.33	107	RPP-Summer	$5.33		
Transmission - Network	kWh	107	$0.0038	$0.40	107	$0.0038	$0.40		
Transmission - Connection	kWh	107	$0.0071	$0.76	107	$0.0071	$0.76		
Wholesale Market Service	kWh	107	$0.0052	$0.55	107	$0.0052	$0.55		
Rural Rate Protection	kWh	107	$0.0010	$0.11	107	$0.0010	$0.11		
Debt Retirement Charge	kWh	100	$0.0070	$0.70	100	$0.0070	$0.70		
TOTAL BILL				**$21.20**			**$22.81**	**$1.61**	**7.6%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential RPP: **Summer**

250 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	250	$0.0198	$4.95	250	$0.0211	$5.28	$0.33	6.6%
Sub-Total (Distribution)				**$16.32**			**$18.09**	**$1.77**	**10.8%**
Deferral/Variance	kWh	250			250	$0.0004	$0.10	$0.10	
Electricity (Commodity)	kWh	266	RPP-Summer	$13.31	266	RPP-Summer	$13.31		
Transmission - Network	kWh	266	$0.0038	$1.01	266	$0.0038	$1.01		
Transmission - Connection	kWh	266	$0.0071	$1.89	266	$0.0071	$1.89		
Wholesale Market Service	kWh	266	$0.0052	$1.38	266	$0.0052	$1.38		
Rural Rate Protection	kWh	266	$0.0010	$0.27	266	$0.0010	$0.27		
Debt Retirement Charge	kWh	250	$0.0070	$1.75	250	$0.0070	$1.75		
TOTAL BILL				**$35.93**			**$37.80**	**$1.87**	**5.2%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential RPP: **Summer**

500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	500	$0.0198	$9.90	500	$0.0211	$10.55	$0.65	6.6%
Sub-Total (Distribution)				**$21.27**			**$23.36**	**$2.09**	**9.8%**
Deferral/Variance	kWh	500			500	$0.0004	$0.20	$0.20	
Electricity (Commodity)	kWh	533	RPP-Summer	$26.63	533	RPP-Summer	$26.63		
Transmission - Network	kWh	533	$0.0038	$2.02	533	$0.0038	$2.02		
Transmission - Connection	kWh	533	$0.0071	$3.78	533	$0.0071	$3.78		
Wholesale Market Service	kWh	533	$0.0052	$2.77	533	$0.0052	$2.77		
Rural Rate Protection	kWh	533	$0.0010	$0.53	533	$0.0010	$0.53		
Debt Retirement Charge	kWh	500	$0.0070	$3.50	500	$0.0070	$3.50		
TOTAL BILL				**$60.50**			**$62.79**	**$2.29**	**3.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential RPP: **Summer**

600 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	600	$0.0198	$11.88	600	$0.0211	$12.66	$0.78	6.6%
Sub-Total (Distribution)				**$23.25**			**$25.47**	**$2.22**	**9.5%**
Deferral/Variance	kWh	600			600	$0.0004	$0.24	$0.24	
Electricity (Commodity)	kWh	639	RPP-Summer	$32.30	639	RPP-Summer	$32.30		
Transmission - Network	kWh	639	$0.0038	$2.43	639	$0.0038	$2.43		
Transmission - Connection	kWh	639	$0.0071	$4.54	639	$0.0071	$4.54		
Wholesale Market Service	kWh	639	$0.0052	$3.32	639	$0.0052	$3.32		
Rural Rate Protection	kWh	639	$0.0010	$0.64	639	$0.0010	$0.64		
Debt Retirement Charge	kWh	600	$0.0070	$4.20	600	$0.0070	$4.20		
TOTAL BILL				**$70.68**			**$73.14**	**$2.46**	**3.5%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**
750 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	750	$0.0198	$14.85	750	$0.0211	$15.83	$0.98	6.6%
Sub-Total (Distribution)				**$26.22**			**$28.64**	**$2.42**	**9.2%**
Deferral/Variance	kWh	750			750	$0.0004	$0.30	$0.30	
Electricity (Commodity)	kWh	799	RPP-Summer	$41.73	799	RPP-Summer	$41.73		
Transmission - Network	kWh	799	$0.0038	$3.04	799	$0.0038	$3.04		
Transmission - Connection	kWh	799	$0.0071	$5.67	799	$0.0071	$5.67		
Wholesale Market Service	kWh	799	$0.0052	$4.15	799	$0.0052	$4.15		
Rural Rate Protection	kWh	799	$0.0010	$0.80	799	$0.0010	$0.80		
Debt Retirement Charge	kWh	750	$0.0070	$5.25	750	$0.0070	$5.25		
TOTAL BILL				**$86.86**			**$89.58**	**$2.72**	**3.1%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential RPP: **Summer**
1,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	1,000	$0.0198	$19.80	1,000	$0.0211	$21.10	$1.30	6.6%
Sub-Total (Distribution)				**$31.17**			**$33.91**	**$2.74**	**8.8%**
Deferral/Variance	kWh	1,000			1,000	$0.0004	$0.40	$0.40	
Electricity (Commodity)	kWh	1,065	RPP-Summer	$57.44	1,065	RPP-Summer	$57.44		
Transmission - Network	kWh	1,065	$0.0038	$4.05	1,065	$0.0038	$4.05		
Transmission - Connection	kWh	1,065	$0.0071	$7.56	1,065	$0.0071	$7.56		
Wholesale Market Service	kWh	1,065	$0.0052	$5.54	1,065	$0.0052	$5.54		
Rural Rate Protection	kWh	1,065	$0.0010	$1.07	1,065	$0.0010	$1.07		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$113.83**			**$116.97**	**$3.14**	**2.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Residential RPP: **Summer**
1,500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	1,500	$0.0198	$29.70	1,500	$0.0211	$31.65	$1.95	6.6%
Sub-Total (Distribution)				**$41.07**			**$44.46**	**$3.39**	**8.3%**
Deferral/Variance	kWh	1,500			1,500	$0.0004	$0.60	$0.60	
Electricity (Commodity)	kWh	1,598	RPP-Summer	$88.86	1,598	RPP-Summer	$88.86		
Transmission - Network	kWh	1,598	$0.0038	$6.07	1,598	$0.0038	$6.07		
Transmission - Connection	kWh	1,598	$0.0071	$11.34	1,598	$0.0071	$11.34		
Wholesale Market Service	kWh	1,598	$0.0052	$8.31	1,598	$0.0052	$8.31		
Rural Rate Protection	kWh	1,598	$0.0010	$1.60	1,598	$0.0010	$1.60		
Debt Retirement Charge	kWh	1,500	$0.0070	$10.50	1,500	$0.0070	$10.50		
TOTAL BILL				**$167.75**			**$171.74**	**$3.99**	**2.4%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
2,000		Summer	$9.68	23.8%	$10.48	5.0%
2,500		Summer	$11.23	23.6%	$12.23	4.7%
4,000		Summer	$15.88	23.1%	$17.48	4.3%
5,000		Summer	$18.98	23.0%	$20.98	4.1%
10,000		Summer	$34.48	22.6%	$38.48	3.8%
12,500		Summer	$42.23	22.5%	$47.23	3.7%
15,000		Summer	$49.98	22.5%	$55.98	3.7%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**

2,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	2,000	$0.0140	$28.00	2,000	$0.0171	$34.20	$6.20	22.1%
Sub-Total (Distribution)				**$40.61**			**$50.29**	**$9.68**	**23.8%**
Deferral/Variance	kWh	2,000			2,000	$0.0004	$0.80	$0.80	
Electricity (Commodity)	kWh	2,130	RPP-Summer	$120.28	2,130	RPP-Summer	$120.28		
Transmission - Network	kWh	2,130	$0.0034	$7.24	2,130	$0.0034	$7.24		
Transmission - Connection	kWh	2,130	$0.0065	$13.85	2,130	$0.0065	$13.85		
Wholesale Market Service	kWh	2,130	$0.0052	$11.08	2,130	$0.0052	$11.08		
Rural Rate Protection	kWh	2,130	$0.0010	$2.13	2,130	$0.0010	$2.13		
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
TOTAL BILL				**$209.19**			**$219.67**	**$10.48**	**5.0%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**

2,500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	2,500	$0.0140	$35.00	2,500	$0.0171	$42.75	$7.75	22.1%
Sub-Total (Distribution)				**$47.61**			**$58.84**	**$11.23**	**23.6%**
Deferral/Variance	kWh	2,500			2,500	$0.0004	$1.00	$1.00	
Electricity (Commodity)	kWh	2,663	RPP-Summer	$151.70	2,663	RPP-Summer	$151.70		
Transmission - Network	kWh	2,663	$0.0034	$9.05	2,663	$0.0034	$9.05		
Transmission - Connection	kWh	2,663	$0.0065	$17.31	2,663	$0.0065	$17.31		
Wholesale Market Service	kWh	2,663	$0.0052	$13.85	2,663	$0.0052	$13.85		
Rural Rate Protection	kWh	2,663	$0.0010	$2.66	2,663	$0.0010	$2.66		
Debt Retirement Charge	kWh	2,500	$0.0070	$17.50	2,500	$0.0070	$17.50		
TOTAL BILL				**$259.68**			**$271.91**	**$12.23**	**4.7%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**

4,000 kWh's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	4,000	$0.0140	$56.00	4,000	$0.0171	$68.40	$12.40	22.1%
Sub-Total (Distribution)				**$68.61**			**$84.49**	**$15.88**	**23.1%**
Deferral/Variance	kWh	4,000			4,000	$0.0004	$1.60	$1.60	
Electricity (Commodity)	kWh	4,260	RPP-Summer	$245.96	4,260	RPP-Summer	$245.96		
Transmission - Network	kWh	4,260	$0.0034	$14.49	4,260	$0.0034	$14.49		
Transmission - Connection	kWh	4,260	$0.0065	$27.69	4,260	$0.0065	$27.69		
Wholesale Market Service	kWh	4,260	$0.0052	$22.15	4,260	$0.0052	$22.15		
Rural Rate Protection	kWh	4,260	$0.0010	$4.26	4,260	$0.0010	$4.26		
Debt Retirement Charge	kWh	4,000	$0.0070	$28.00	4,000	$0.0070	$28.00		
TOTAL BILL				**$411.16**			**$428.64**	**$17.48**	**4.3%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**

5,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	5,000	$0.0140	$70.00	5,000	$0.0171	$85.50	$15.50	22.1%
Sub-Total (Distribution)				**$82.61**			**$101.59**	**$18.98**	**23.0%**
Deferral/Variance	kWh	5,000			5,000	$0.0004	$2.00	$2.00	
Electricity (Commodity)	kWh	5,326	RPP-Summer	$308.80	5,326	RPP-Summer	$308.80		
Transmission - Network	kWh	5,326	$0.0034	$18.11	5,326	$0.0034	$18.11		
Transmission - Connection	kWh	5,326	$0.0065	$34.62	5,326	$0.0065	$34.62		
Wholesale Market Service	kWh	5,326	$0.0052	$27.69	5,326	$0.0052	$27.69		
Rural Rate Protection	kWh	5,326	$0.0010	$5.33	5,326	$0.0010	$5.33		
Debt Retirement Charge	kWh	5,000	$0.0070	$35.00	5,000	$0.0070	$35.00		
TOTAL BILL				**$512.16**			**$533.14**	**$20.98**	**4.1%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**
10,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	10,000	$0.0140	$140.00	10,000	$0.0171	$171.00	$31.00	22.1%
Sub-Total (Distribution)				**$152.61**			**$187.09**	**$34.48**	**22.6%**
Deferral/Variance	kWh	10,000			10,000	$0.0004	$4.00	$4.00	
Electricity (Commodity)	kWh	10,651	RPP-Summer	$623.01	10,651	RPP-Summer	$623.01		
Transmission - Network	kWh	10,651	$0.0034	$36.21	10,651	$0.0034	$36.21		
Transmission - Connection	kWh	10,651	$0.0065	$69.23	10,651	$0.0065	$69.23		
Wholesale Market Service	kWh	10,651	$0.0052	$55.39	10,651	$0.0052	$55.39		
Rural Rate Protection	kWh	10,651	$0.0010	$10.65	10,651	$0.0010	$10.65		
Debt Retirement Charge	kWh	10,000	$0.0070	$70.00	10,000	$0.0070	$70.00		
TOTAL BILL				**$1,017.10**			**$1,055.58**	**$38.48**	**3.8%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**

12,500 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	12,500	$0.0140	$175.00	12,500	$0.0171	$213.75	$38.75	22.1%
Sub-Total (Distribution)				**$187.61**			**$229.84**	**$42.23**	**22.5%**
Deferral/Variance	kWh	12,500			12,500	$0.0004	$5.00	$5.00	
Electricity (Commodity)	kWh	13,314	RPP-Summer	$780.11	13,314	RPP-Summer	$780.11		
Transmission - Network	kWh	13,314	$0.0034	$45.27	13,314	$0.0034	$45.27		
Transmission - Connection	kWh	13,314	$0.0065	$86.54	13,314	$0.0065	$86.54		
Wholesale Market Service	kWh	13,314	$0.0052	$69.23	13,314	$0.0052	$69.23		
Rural Rate Protection	kWh	13,314	$0.0010	$13.31	13,314	$0.0010	$13.31		
Debt Retirement Charge	kWh	12,500	$0.0070	$87.50	12,500	$0.0070	$87.50		
TOTAL BILL				**$1,269.57**			**$1,316.80**	**$47.23**	**3.7%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service <50 kW **RPP: Summer**
15,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	15,000	$0.0140	$210.00	15,000	$0.0171	$256.50	$46.50	22.1%
Sub-Total (Distribution)				**$222.61**			**$272.59**	**$49.98**	**22.5%**
Deferral/Variance	kWh	15,000			15,000	$0.0004	$6.00	$6.00	
Electricity (Commodity)	kWh	15,977	RPP-Summer	$937.21	15,977	RPP-Summer	$937.21		
Transmission - Network	kWh	15,977	$0.0034	$54.32	15,977	$0.0034	$54.32		
Transmission - Connection	kWh	15,977	$0.0065	$103.85	15,977	$0.0065	$103.85		
Wholesale Market Service	kWh	15,977	$0.0052	$83.08	15,977	$0.0052	$83.08		
Rural Rate Protection	kWh	15,977	$0.0010	$15.98	15,977	$0.0010	$15.98		
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,522.05**			**$1,578.03**	**$55.98**	**3.7%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50

	Volume			Distribution Charges		Total Bill	
	kWh *	kW	RPP?	$ change	% change	$ change	% change
ADM	800,000	1,850	n/a	$3,550.51	82.6%	$3,854.84	5.6%
Schott	750,000	1,800	n/a	$3,455.76	82.7%	$3,751.86	5.8%
Elcan	1,383,000	2,650	n/a	$5,066.43	82.4%	$5,502.36	4.8%
	400,000	274	n/a	$564.14	87.0%	$609.21	2.0%
	1,000,000	685	n/a	$1,342.95	84.0%	$1,455.63	1.9%
	1,500,000	1,028	n/a	$1,992.90	83.3%	$2,162.01	1.9%
	2,000,000	1,371	n/a	$2,642.85	82.9%	$2,868.38	1.9%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

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General Service >50 Kw **RPP: n/a**

800,000 kWh's
1,850 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,850	$2.3148	$4,282.38	1,850	$4.2097	$7,787.95	$3,505.57	81.9%
Sub-Total (Distribution)				**$4,296.43**			**$7,846.94**	**$3,550.51**	**82.6%**
Deferral/Variance	kW	1,850			1,850	$0.1645	$304.33	$304.33	
Electricity (Commodity)	kWh	852,080	$0.0545	$46,438.36	852,080	$0.0545	$46,438.36		
Transmission - Network	kW	1,850	$1.4180	$2,623.30	1,850	$1.4180	$2,623.30		
Transmission - Connection	kW	1,850	$2.5532	$4,723.42	1,850	$2.5532	$4,723.42		
Wholesale Market Service	kWh	852,080	$0.0052	$4,430.82	852,080	$0.0052	$4,430.82		
Rural Rate Protection	kWh	852,080	$0.0010	$852.08	852,080	$0.0010	$852.08		
Debt Retirement Charge	kWh	800,000	$0.0070	$5,600.00	800,000	$0.0070	$5,600.00		
TOTAL BILL				**$68,964.41**			**$72,819.25**	**$3,854.84**	**5.6%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

750,000 kWh's
1,800 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,800	$2.3148	$4,166.64	1,800	$4.2097	$7,577.46	$3,410.82	81.9%
Sub-Total (Distribution)				**$4,180.69**			**$7,636.45**	**$3,455.76**	**82.7%**
Deferral/Variance	kW	1,800			1,800	$0.1645	$296.10	$296.10	
Electricity (Commodity)	kWh	798,825	$0.0545	$43,535.96	798,825	$0.0545	$43,535.96		
Transmission - Network	kW	1,800	$1.4180	$2,552.40	1,800	$1.4180	$2,552.40		
Transmission - Connection	kW	1,800	$2.5532	$4,595.76	1,800	$2.5532	$4,595.76		
Wholesale Market Service	kWh	798,825	$0.0052	$4,153.89	798,825	$0.0052	$4,153.89		
Rural Rate Protection	kWh	798,825	$0.0010	$798.83	798,825	$0.0010	$798.83		
Debt Retirement Charge	kWh	750,000	$0.0070	$5,250.00	750,000	$0.0070	$5,250.00		
TOTAL BILL				**$65,067.53**			**$68,819.39**	**$3,751.86**	**5.8%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

1,383,000 kWh's
2,650 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	2,650	$2.3148	$6,134.22	2,650	$4.2097	$11,155.71	$5,021.49	81.9%
Sub-Total (Distribution)				**$6,148.27**			**$11,214.70**	**$5,066.43**	**82.4%**
Deferral/Variance	kW	2,650			2,650	$0.1645	$435.93	$435.93	
Electricity (Commodity)	kWh	1,473,033	$0.0545	$80,280.31	1,473,033	$0.0545	$80,280.31		
Transmission - Network	kW	2,650	$1.4180	$3,757.70	2,650	$1.4180	$3,757.70		
Transmission - Connection	kW	2,650	$2.5532	$6,765.98	2,650	$2.5532	$6,765.98		
Wholesale Market Service	kWh	1,473,033	$0.0052	$7,659.77	1,473,033	$0.0052	$7,659.77		
Rural Rate Protection	kWh	1,473,033	$0.0010	$1,473.03	1,473,033	$0.0010	$1,473.03		
Debt Retirement Charge	kWh	1,383,000	$0.0070	$9,681.00	1,383,000	$0.0070	$9,681.00		
TOTAL BILL				**$115,766.06**			**$121,268.42**	**$5,502.36**	**4.8%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

400,000 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
274 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	274	$2.3148	$634.26	274	$4.2097	$1,153.46	$519.20	81.9%
Sub-Total (Distribution)				**$648.31**			**$1,212.45**	**$564.14**	**87.0%**
Deferral/Variance	kW	274			274	$0.1645	$45.07	$45.07	
Electricity (Commodity)	kWh	426,040	$0.0545	$23,219.18	426,040	$0.0545	$23,219.18		
Transmission - Network	kW	274	$1.4180	$388.53	274	$1.4180	$388.53		
Transmission - Connection	kW	274	$2.5532	$699.58	274	$2.5532	$699.58		
Wholesale Market Service	kWh	426,040	$0.0052	$2,215.41	426,040	$0.0052	$2,215.41		
Rural Rate Protection	kWh	426,040	$0.0010	$426.04	426,040	$0.0010	$426.04		
Debt Retirement Charge	kWh	400,000	$0.0070	$2,800.00	400,000	$0.0070	$2,800.00		
TOTAL BILL				**$30,397.05**			**$31,006.26**	**$609.21**	**2.0%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

1,000,000 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
685 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	685	$2.3148	$1,585.64	685	$4.2097	$2,883.64	$1,298.01	81.9%
Sub-Total (Distribution)				**$1,599.69**			**$2,942.63**	**$1,342.95**	**84.0%**
Deferral/Variance	kW	685			685	$0.1645	$112.68	$112.68	
Electricity (Commodity)	kWh	1,065,100	$0.0545	$58,047.95	1,065,100	$0.0545	$58,047.95		
Transmission - Network	kW	685	$1.4180	$971.33	685	$1.4180	$971.33		
Transmission - Connection	kW	685	$2.5532	$1,748.94	685	$2.5532	$1,748.94		
Wholesale Market Service	kWh	1,065,100	$0.0052	$5,538.52	1,065,100	$0.0052	$5,538.52		
Rural Rate Protection	kWh	1,065,100	$0.0010	$1,065.10	1,065,100	$0.0010	$1,065.10		
Debt Retirement Charge	kWh	1,000,000	$0.0070	$7,000.00	1,000,000	$0.0070	$7,000.00		
TOTAL BILL				**$75,971.53**			**$77,427.15**	**$1,455.63**	**1.9%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

1,500,000 kWh's
1,028 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,028	$2.3148	$2,379.61	1,028	$4.2097	$4,327.57	$1,947.96	81.9%
Sub-Total (Distribution)				**$2,393.66**			**$4,386.56**	**$1,992.90**	**83.3%**
Deferral/Variance	kW	1,028			1,028	$0.1645	$169.11	$169.11	
Electricity (Commodity)	kWh	1,597,650	$0.0545	$87,071.93	1,597,650	$0.0545	$87,071.93		
Transmission - Network	kW	1,028	$1.4180	$1,457.70	1,028	$1.4180	$1,457.70		
Transmission - Connection	kW	1,028	$2.5532	$2,624.69	1,028	$2.5532	$2,624.69		
Wholesale Market Service	kWh	1,597,650	$0.0052	$8,307.78	1,597,650	$0.0052	$8,307.78		
Rural Rate Protection	kWh	1,597,650	$0.0010	$1,597.65	1,597,650	$0.0010	$1,597.65		
Debt Retirement Charge	kWh	1,500,000	$0.0070	$10,500.00	1,500,000	$0.0070	$10,500.00		
TOTAL BILL				**$113,953.41**			**$116,115.42**	**$2,162.01**	**1.9%**

Customer Bill Impacts

RPP rates per sheet Y7

General Service >50 Kw **RPP: n/a**

2,000,000 kWh's
1,371 kW's

	Metric	2008 BILL Volume	Rate	Charge	2009 BILL Volume	Rate	Charge	CHANGE IMPACT	%
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,371	$2.3148	$3,173.59	1,371	$4.2097	$5,771.50	$2,597.91	81.9%
Sub-Total (Distribution)				**$3,187.64**			**$5,830.49**	**$2,642.85**	**82.9%**
Deferral/Variance	kW	1,371			1,371	$0.1645	$225.53	$225.53	
Electricity (Commodity)	kWh	2,130,200	$0.0545	$116,095.90	2,130,200	$0.0545	$116,095.90		
Transmission - Network	kW	1,371	$1.4180	$1,944.08	1,371	$1.4180	$1,944.08		
Transmission - Connection	kW	1,371	$2.5532	$3,500.44	1,371	$2.5532	$3,500.44		
Wholesale Market Service	kWh	2,130,200	$0.0052	$11,077.04	2,130,200	$0.0052	$11,077.04		
Rural Rate Protection	kWh	2,130,200	$0.0010	$2,130.20	2,130,200	$0.0010	$2,130.20		
Debt Retirement Charge	kWh	2,000,000	$0.0070	$14,000.00	2,000,000	$0.0070	$14,000.00		
TOTAL BILL				**$151,935.30**			**$154,803.68**	**$2,868.38**	**1.9%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting

	Volume			Distribution Charges		Total Bill	
	kWh *	kW	RPP?	$ change	% change	$ change	% change
Town	59	0.18	Summer	$2.64	>100%	$2.67	45.3%
Town	84	0.18	Summer	$2.64	>100%	$2.67	35.5%
	71	0.05	Summer	$2.05	>100%	$2.06	34.4%
	286	0.20	Summer	$2.72	>100%	$2.75	13.0%
	714	0.49	Summer	$4.05	>100%	$4.13	7.8%
	1,071	0.73	Summer	$5.16	>100%	$5.27	6.5%
	1,429	0.98	Summer	$6.27	>100%	$6.42	5.8%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

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Street Lighting **RPP: Summer**

59 kWh's		2008 BILL			2009 BILL			CHANGE IMPACT	
0.18 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.18	$2.3727	$0.42	0	$6.9080	$1.23	$0.81	>100%
Sub-Total (Distribution)				**$1.38**			**$4.02**	**$2.64**	**>100%**
Deferral/Variance	kW	0.18			0	$0.1538	$0.03	$0.03	
Electricity (Commodity)	kWh	63	RPP-Summer	$3.16	63	RPP-Summer	$3.16		
Transmission - Network	kW	0.18	$1.0694	$0.19	0	$1.0694	$0.19		
Transmission - Connection	kW	0.18	$1.9738	$0.35	0	$1.9738	$0.35		
Wholesale Market Service	kWh	63	$0.0052	$0.33	63	$0.0052	$0.33		
Rural Rate Protection	kWh	63	$0.0010	$0.06	63	$0.0010	$0.06		
Debt Retirement Charge	kWh	59	$0.0070	$0.42	59	$0.0070	$0.42		
TOTAL BILL				**$5.89**			**$8.56**	**$2.67**	**45.3%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

84 kWh's
0.18 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.18	$2.3727	$0.42	0	$6.9080	$1.23	$0.81	>100%
Sub-Total (Distribution)				**$1.38**			**$4.02**	**$2.64**	**>100%**
Deferral/Variance	kW	0.18			0	$0.1538	$0.03	$0.03	
Electricity (Commodity)	kWh	89	RPP-Summer	$4.46	89	RPP-Summer	$4.46		
Transmission - Network	kW	0.18	$1.0694	$0.19	0	$1.0694	$0.19		
Transmission - Connection	kW	0.18	$1.9738	$0.35	0	$1.9738	$0.35		
Wholesale Market Service	kWh	89	$0.0052	$0.46	89	$0.0052	$0.46		
Rural Rate Protection	kWh	89	$0.0010	$0.09	89	$0.0010	$0.09		
Debt Retirement Charge	kWh	84	$0.0070	$0.59	84	$0.0070	$0.59		
TOTAL BILL				**$7.52**			**$10.19**	**$2.67**	**35.5%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

71 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
0.05 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.05	$2.3727	$0.12	0	$6.9080	$0.34	$0.22	>100%
Sub-Total (Distribution)				**$1.08**			**$3.13**	**$2.05**	**>100%**
Deferral/Variance	kW	0.05			0	$0.1538	$0.01	$0.01	
Electricity (Commodity)	kWh	76	RPP-Summer	$3.80	76	RPP-Summer	$3.80		
Transmission - Network	kW	0.05	$1.0694	$0.05	0	$1.0694	$0.05		
Transmission - Connection	kW	0.05	$1.9738	$0.10	0	$1.9738	$0.10		
Wholesale Market Service	kWh	76	$0.0052	$0.40	76	$0.0052	$0.40		
Rural Rate Protection	kWh	76	$0.0010	$0.08	76	$0.0010	$0.08		
Debt Retirement Charge	kWh	71	$0.0070	$0.50	71	$0.0070	$0.50		
TOTAL BILL				**$6.01**			**$8.07**	**$2.06**	**34.4%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

286 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
0.20 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.20	$2.3727	$0.46	0	$6.9080	$1.35	$0.89	>100%
Sub-Total (Distribution)				**$1.42**			**$4.14**	**$2.72**	**>100%**
Deferral/Variance	kW	0.20			0	$0.1538	$0.03	$0.03	
Electricity (Commodity)	kWh	304	RPP-Summer	$15.22	304	RPP-Summer	$15.22		
Transmission - Network	kW	0.20	$1.0694	$0.21	0	$1.0694	$0.21		
Transmission - Connection	kW	0.20	$1.9738	$0.39	0	$1.9738	$0.39		
Wholesale Market Service	kWh	304	$0.0052	$1.58	304	$0.0052	$1.58		
Rural Rate Protection	kWh	304	$0.0010	$0.30	304	$0.0010	$0.30		
Debt Retirement Charge	kWh	286	$0.0070	$2.00	286	$0.0070	$2.00		
TOTAL BILL				**$21.12**			**$23.87**	**$2.75**	**13.0%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

714 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
0.49 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	0.49	$2.3727	$1.16	0	$6.9080	$3.38	$2.22	>100%
Sub-Total (Distribution)				**$2.12**			**$6.17**	**$4.05**	**>100%**
Deferral/Variance	kW	0.49			0	$0.1538	$0.08	$0.08	
Electricity (Commodity)	kWh	761	RPP-Summer	$39.49	761	RPP-Summer	$39.49		
Transmission - Network	kW	0.49	$1.0694	$0.52	0	$1.0694	$0.52		
Transmission - Connection	kW	0.49	$1.9738	$0.97	0	$1.9738	$0.97		
Wholesale Market Service	kWh	761	$0.0052	$3.96	761	$0.0052	$3.96		
Rural Rate Protection	kWh	761	$0.0010	$0.76	761	$0.0010	$0.76		
Debt Retirement Charge	kWh	714	$0.0070	$5.00	714	$0.0070	$5.00		
TOTAL BILL				**$52.82**			**$56.95**	**$4.13**	**7.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

1,071 kWh's 1 kW's	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	1	$2.3727	$1.74	1	$6.9080	$5.07	$3.33	>100%
Sub-Total (Distribution)				**$2.70**			**$7.86**	**$5.16**	**>100%**
Deferral/Variance	kW	1			1	$0.1538	$0.11	$0.11	
Electricity (Commodity)	kWh	1,141	RPP-Summer	$61.93	1,141	RPP-Summer	$61.93		
Transmission - Network	kW	1	$1.0694	$0.79	1	$1.0694	$0.79		
Transmission - Connection	kW	1	$1.9738	$1.45	1	$1.9738	$1.45		
Wholesale Market Service	kWh	1,141	$0.0052	$5.93	1,141	$0.0052	$5.93		
Rural Rate Protection	kWh	1,141	$0.0010	$1.14	1,141	$0.0010	$1.14		
Debt Retirement Charge	kWh	1,071	$0.0070	$7.50	1,071	$0.0070	$7.50		
TOTAL BILL				**$81.44**			**$86.71**	**$5.27**	**6.5%**

Customer Bill Impacts

RPP rates per sheet Y7

Street Lighting **RPP: Summer**

1,429 kWh's 1 kW's	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$0.96			$2.79	$1.83	>100%
Distribution	kW	1	$2.3727	$2.32	1	$6.9080	$6.76	$4.44	>100%
Sub-Total (Distribution)				**$3.28**			**$9.55**	**$6.27**	**>100%**
Deferral/Variance	kW	1			1	$0.1538	$0.15	$0.15	
Electricity (Commodity)	kWh	1,522	RPP-Summer	$84.37	1,522	RPP-Summer	$84.37		
Transmission - Network	kW	1	$1.0694	$1.05	1	$1.0694	$1.05		
Transmission - Connection	kW	1	$1.9738	$1.93	1	$1.9738	$1.93		
Wholesale Market Service	kWh	1,522	$0.0052	$7.91	1,522	$0.0052	$7.91		
Rural Rate Protection	kWh	1,522	$0.0010	$1.52	1,522	$0.0010	$1.52		
Debt Retirement Charge	kWh	1,429	$0.0070	$10.00	1,429	$0.0070	$10.00		
TOTAL BILL				**$110.06**			**$116.48**	**$6.42**	**5.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
15,000	10.00	Summer	$280.43	>100%	$281.85	23.5%
40,000	27.00	Summer	$732.00	>100%	$735.84	22.9%
100,000	69.00	Summer	$1,847.67	>100%	$1,857.49	23.1%
400,000	274.00	Summer	$7,293.19	>100%	$7,332.18	22.8%
1,000,000	685.00	Summer	$18,210.79	>100%	$18,308.27	22.8%
1,500,000	1,028.00	Summer	$27,322.07	>100%	$27,468.35	22.8%
2,000,000	1,371.00	Summer	$36,433.35	>100%	$36,628.44	22.8%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**

15,000 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
10 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	10	$2.6254	$26.25	10	$29.1889	$291.89	$265.64	>100%
Sub-Total (Distribution)				**$27.71**			**$308.14**	**$280.43**	**>100%**
Deferral/Variance	kW	10			10	$0.1423	$1.42	$1.42	
Electricity (Commodity)	kWh	15,977	RPP-Summer	$937.21	15,977	RPP-Summer	$937.21		
Transmission - Network	kW	10	$1.0749	$10.75	10	$1.0749	$10.75		
Transmission - Connection	kW	10	$2.0150	$20.15	10	$2.0150	$20.15		
Wholesale Market Service	kWh	15,977	$0.0052	$83.08	15,977	$0.0052	$83.08		
Rural Rate Protection	kWh	15,977	$0.0010	$15.98	15,977	$0.0010	$15.98		
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,199.88**			**$1,481.73**	**$281.85**	**23.5%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**

40,000 kWh's / 27 kW's	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	27	$2.6254	$70.89	27	$29.1889	$788.10	$717.21	>100%
Sub-Total (Distribution)				**$72.35**			**$804.35**	**$732.00**	**>100%**
Deferral/Variance	kW	27			27	$0.1423	$3.84	$3.84	
Electricity (Commodity)	kWh	42,604	RPP-Summer	$2,508.24	42,604	RPP-Summer	$2,508.24		
Transmission - Network	kW	27	$1.0749	$29.02	27	$1.0749	$29.02		
Transmission - Connection	kW	27	$2.0150	$54.41	27	$2.0150	$54.41		
Wholesale Market Service	kWh	42,604	$0.0052	$221.54	42,604	$0.0052	$221.54		
Rural Rate Protection	kWh	42,604	$0.0010	$42.60	42,604	$0.0010	$42.60		
Debt Retirement Charge	kWh	40,000	$0.0070	$280.00	40,000	$0.0070	$280.00		
TOTAL BILL				**$3,208.16**			**$3,944.00**	**$735.84**	**22.9%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**
100,000 kWh's
69 kW's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	69	$2.6254	$181.15	69	$29.1889	$2,014.03	$1,832.88	>100%
Sub-Total (Distribution)				**$182.61**			**$2,030.28**	**$1,847.67**	**>100%**
Deferral/Variance	kW	69			69	$0.1423	$9.82	$9.82	
Electricity (Commodity)	kWh	106,510	RPP-Summer	$6,278.69	106,510	RPP-Summer	$6,278.69		
Transmission - Network	kW	69	$1.0749	$74.17	69	$1.0749	$74.17		
Transmission - Connection	kW	69	$2.0150	$139.04	69	$2.0150	$139.04		
Wholesale Market Service	kWh	106,510	$0.0052	$553.85	106,510	$0.0052	$553.85		
Rural Rate Protection	kWh	106,510	$0.0010	$106.51	106,510	$0.0010	$106.51		
Debt Retirement Charge	kWh	100,000	$0.0070	$700.00	100,000	$0.0070	$700.00		
TOTAL BILL				**$8,034.87**			**$9,892.36**	**$1,857.49**	**23.1%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**

400,000 kWh's		**2008 BILL**			**2009 BILL**			**CHANGE IMPACT**	
274 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	274	$2.6254	$719.36	274	$29.1889	$7,997.76	$7,278.40	>100%
Sub-Total (Distribution)				**$720.82**			**$8,014.01**	**$7,293.19**	**>100%**
Deferral/Variance	kW	274			274	$0.1423	$38.99	$38.99	
Electricity (Commodity)	kWh	426,040	RPP-Summer	$25,130.96	426,040	RPP-Summer	$25,130.96		
Transmission - Network	kW	274	$1.0749	$294.52	274	$1.0749	$294.52		
Transmission - Connection	kW	274	$2.0150	$552.11	274	$2.0150	$552.11		
Wholesale Market Service	kWh	426,040	$0.0052	$2,215.41	426,040	$0.0052	$2,215.41		
Rural Rate Protection	kWh	426,040	$0.0010	$426.04	426,040	$0.0010	$426.04		
Debt Retirement Charge	kWh	400,000	$0.0070	$2,800.00	400,000	$0.0070	$2,800.00		
TOTAL BILL				**$32,139.86**			**$39,472.04**	**$7,332.18**	**22.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**
1,000,000 kWh's
685 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	685	$2.6254	$1,798.40	685	$29.1889	$19,994.40	$18,196.00	>100%
Sub-Total (Distribution)				**$1,799.86**			**$20,010.65**	**$18,210.79**	**>100%**
Deferral/Variance	kW	685			685	$0.1423	$97.48	$97.48	
Electricity (Commodity)	kWh	1,065,100	RPP-Summer	$62,835.50	1,065,100	RPP-Summer	$62,835.50		
Transmission - Network	kW	685	$1.0749	$736.31	685	$1.0749	$736.31		
Transmission - Connection	kW	685	$2.0150	$1,380.28	685	$2.0150	$1,380.28		
Wholesale Market Service	kWh	1,065,100	$0.0052	$5,538.52	1,065,100	$0.0052	$5,538.52		
Rural Rate Protection	kWh	1,065,100	$0.0010	$1,065.10	1,065,100	$0.0010	$1,065.10		
Debt Retirement Charge	kWh	1,000,000	$0.0070	$7,000.00	1,000,000	$0.0070	$7,000.00		
TOTAL BILL				**$80,355.57**			**$98,663.84**	**$18,308.27**	**22.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**

1,500,000 kWh's
1,028 kW's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	1,028	$2.6254	$2,698.91	1,028	$29.1889	$30,006.19	$27,307.28	>100%
Sub-Total (Distribution)				**$2,700.37**			**$30,022.44**	**$27,322.07**	**>100%**
Deferral/Variance	kW	1,028			1,028	$0.1423	$146.28	$146.28	
Electricity (Commodity)	kWh	1,597,650	RPP-Summer	$94,255.95	1,597,650	RPP-Summer	$94,255.95		
Transmission - Network	kW	1,028	$1.0749	$1,105.00	1,028	$1.0749	$1,105.00		
Transmission - Connection	kW	1,028	$2.0150	$2,071.42	1,028	$2.0150	$2,071.42		
Wholesale Market Service	kWh	1,597,650	$0.0052	$8,307.78	1,597,650	$0.0052	$8,307.78		
Rural Rate Protection	kWh	1,597,650	$0.0010	$1,597.65	1,597,650	$0.0010	$1,597.65		
Debt Retirement Charge	kWh	1,500,000	$0.0070	$10,500.00	1,500,000	$0.0070	$10,500.00		
TOTAL BILL				**$120,538.17**			**$148,006.52**	**$27,468.35**	**22.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Sentinel Lighting **RPP: Summer**

2,000,000 kWh's
1,371 kW's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
Monthly Service Charge				$1.46			$16.25	$14.79	>100%
Distribution	kW	1,371	$2.6254	$3,599.42	1,371	$29.1889	$40,017.98	$36,418.56	>100%
Sub-Total (Distribution)				**$3,600.88**			**$40,034.23**	**$36,433.35**	**>100%**
Deferral/Variance	kW	1,371			1,371	$0.1423	$195.09	$195.09	
Electricity (Commodity)	kWh	2,130,200	RPP-Summer	$125,676.40	2,130,200	RPP-Summer	$125,676.40		
Transmission - Network	kW	1,371	$1.0749	$1,473.69	1,371	$1.0749	$1,473.69		
Transmission - Connection	kW	1,371	$2.0150	$2,762.57	1,371	$2.0150	$2,762.57		
Wholesale Market Service	kWh	2,130,200	$0.0052	$11,077.04	2,130,200	$0.0052	$11,077.04		
Rural Rate Protection	kWh	2,130,200	$0.0010	$2,130.20	2,130,200	$0.0010	$2,130.20		
Debt Retirement Charge	kWh	2,000,000	$0.0070	$14,000.00	2,000,000	$0.0070	$14,000.00		
TOTAL BILL				**$160,720.78**			**$197,349.22**	**$36,628.44**	**22.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered

Volume			Distribution Charges		Total Bill	
kWh *	kW	RPP?	$ change	% change	$ change	% change
15,000		Summer	$181.03	81.4%	$187.03	12.3%
40,000		Summer	$466.03	81.4%	$482.03	11.9%
100,000		Summer	$1,150.03	81.4%	$1,190.03	11.8%
400,000		Summer	$4,570.03	81.4%	$4,730.03	11.7%
1,000,000		Summer	$11,410.03	81.4%	$11,810.03	11.7%
1,500,000		Summer	$17,110.03	81.4%	$17,710.03	11.7%
2,000,000		Summer	$22,810.03	81.4%	$23,610.03	11.7%

** Loss Factors (sheet F6) apply to certain pass-through charges (per sheet Y4)*

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**

15,000 kWh's

	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	15,000	$0.0140	$210.00	15,000	$0.0254	$381.00	$171.00	81.4%
Sub-Total (Distribution)				**$222.35**			**$403.38**	**$181.03**	**81.4%**
Deferral/Variance	kWh	15,000			15,000	$0.0004	$6.00	$6.00	
Electricity (Commodity)	kWh	15,977	RPP-Summer	$937.21	15,977	RPP-Summer	$937.21		
Transmission - Network	kWh	15,977	$0.0034	$54.32	15,977	$0.0034	$54.32		
Transmission - Connection	kWh	15,977	$0.0065	$103.85	15,977	$0.0065	$103.85		
Wholesale Market Service	kWh	15,977	$0.0052	$83.08	15,977	$0.0052	$83.08		
Rural Rate Protection	kWh	15,977	$0.0010	$15.98	15,977	$0.0010	$15.98		
Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
TOTAL BILL				**$1,521.79**			**$1,708.82**	**$187.03**	**12.3%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**

40,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	40,000	$0.0140	$560.00	40,000	$0.0254	$1,016.00	$456.00	81.4%
Sub-Total (Distribution)				**$572.35**			**$1,038.38**	**$466.03**	**81.4%**
Deferral/Variance	kWh	40,000			40,000	$0.0004	$16.00	$16.00	
Electricity (Commodity)	kWh	42,604	RPP-Summer	$2,508.24	42,604	RPP-Summer	$2,508.24		
Transmission - Network	kWh	42,604	$0.0034	$144.85	42,604	$0.0034	$144.85		
Transmission - Connection	kWh	42,604	$0.0065	$276.93	42,604	$0.0065	$276.93		
Wholesale Market Service	kWh	42,604	$0.0052	$221.54	42,604	$0.0052	$221.54		
Rural Rate Protection	kWh	42,604	$0.0010	$42.60	42,604	$0.0010	$42.60		
Debt Retirement Charge	kWh	40,000	$0.0070	$280.00	40,000	$0.0070	$280.00		
TOTAL BILL				**$4,046.51**			**$4,528.54**	**$482.03**	**11.9%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**
100,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	100,000	$0.0140	$1,400.00	100,000	$0.0254	$2,540.00	$1,140.00	81.4%
Sub-Total (Distribution)				**$1,412.35**			**$2,562.38**	**$1,150.03**	**81.4%**
Deferral/Variance	kWh	100,000			100,000	$0.0004	$40.00	$40.00	
Electricity (Commodity)	kWh	106,510	RPP-Summer	$6,278.69	106,510	RPP-Summer	$6,278.69		
Transmission - Network	kWh	106,510	$0.0034	$362.13	106,510	$0.0034	$362.13		
Transmission - Connection	kWh	106,510	$0.0065	$692.32	106,510	$0.0065	$692.32		
Wholesale Market Service	kWh	106,510	$0.0052	$553.85	106,510	$0.0052	$553.85		
Rural Rate Protection	kWh	106,510	$0.0010	$106.51	106,510	$0.0010	$106.51		
Debt Retirement Charge	kWh	100,000	$0.0070	$700.00	100,000	$0.0070	$700.00		
TOTAL BILL				**$10,105.85**			**$11,295.88**	**$1,190.03**	**11.8%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**

400,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	400,000	$0.0140	$5,600.00	400,000	$0.0254	$10,160.00	$4,560.00	81.4%
Sub-Total (Distribution)				**$5,612.35**			**$10,182.38**	**$4,570.03**	**81.4%**
Deferral/Variance	kWh	400,000			400,000	$0.0004	$160.00	$160.00	
Electricity (Commodity)	kWh	426,040	RPP-Summer	$25,130.96	426,040	RPP-Summer	$25,130.96		
Transmission - Network	kWh	426,040	$0.0034	$1,448.54	426,040	$0.0034	$1,448.54		
Transmission - Connection	kWh	426,040	$0.0065	$2,769.26	426,040	$0.0065	$2,769.26		
Wholesale Market Service	kWh	426,040	$0.0052	$2,215.41	426,040	$0.0052	$2,215.41		
Rural Rate Protection	kWh	426,040	$0.0010	$426.04	426,040	$0.0010	$426.04		
Debt Retirement Charge	kWh	400,000	$0.0070	$2,800.00	400,000	$0.0070	$2,800.00		
TOTAL BILL				**$40,402.56**			**$45,132.59**	**$4,730.03**	**11.7%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**

1,000,000 kWh's

	Metric	2008 BILL Volume	2008 BILL Rate	2008 BILL Charge	2009 BILL Volume	2009 BILL Rate	2009 BILL Charge	CHANGE IMPACT	%
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	1,000,000	$0.0140	$14,000.00	1,000,000	$0.0254	$25,400.00	$11,400.00	81.4%
Sub-Total (Distribution)				**$14,012.35**			**$25,422.38**	**$11,410.03**	**81.4%**
Deferral/Variance	kWh	1,000,000			1,000,000	$0.0004	$400.00	$400.00	
Electricity (Commodity)	kWh	1,065,100	RPP-Summer	$62,835.50	1,065,100	RPP-Summer	$62,835.50		
Transmission - Network	kWh	1,065,100	$0.0034	$3,621.34	1,065,100	$0.0034	$3,621.34		
Transmission - Connection	kWh	1,065,100	$0.0065	$6,923.15	1,065,100	$0.0065	$6,923.15		
Wholesale Market Service	kWh	1,065,100	$0.0052	$5,538.52	1,065,100	$0.0052	$5,538.52		
Rural Rate Protection	kWh	1,065,100	$0.0010	$1,065.10	1,065,100	$0.0010	$1,065.10		
Debt Retirement Charge	kWh	1,000,000	$0.0070	$7,000.00	1,000,000	$0.0070	$7,000.00		
TOTAL BILL				**$100,995.96**			**$112,805.99**	**$11,810.03**	**11.7%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load RPP: Summer
1,500,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	1,500,000	$0.0140	$21,000.00	1,500,000	$0.0254	$38,100.00	$17,100.00	81.4%
Sub-Total (Distribution)				**$21,012.35**			**$38,122.38**	**$17,110.03**	**81.4%**
Deferral/Variance	kWh	1,500,000			1,500,000	$0.0004	$600.00	$600.00	
Electricity (Commodity)	kWh	1,597,650	RPP-Summer	$94,255.95	1,597,650	RPP-Summer	$94,255.95		
Transmission - Network	kWh	1,597,650	$0.0034	$5,432.01	1,597,650	$0.0034	$5,432.01		
Transmission - Connection	kWh	1,597,650	$0.0065	$10,384.73	1,597,650	$0.0065	$10,384.73		
Wholesale Market Service	kWh	1,597,650	$0.0052	$8,307.78	1,597,650	$0.0052	$8,307.78		
Rural Rate Protection	kWh	1,597,650	$0.0010	$1,597.65	1,597,650	$0.0010	$1,597.65		
Debt Retirement Charge	kWh	1,500,000	$0.0070	$10,500.00	1,500,000	$0.0070	$10,500.00		
TOTAL BILL				**$151,490.47**			**$169,200.50**	**$17,710.03**	**11.7%**

Customer Bill Impacts

RPP rates per sheet Y7

Unmetered Scattered Load **RPP: Summer**
2,000,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
Monthly Service Charge				$12.35			$22.38	$10.03	81.2%
Distribution	kWh	2,000,000	$0.0140	$28,000.00	2,000,000	$0.0254	$50,800.00	$22,800.00	81.4%
Sub-Total (Distribution)				**$28,012.35**			**$50,822.38**	**$22,810.03**	**81.4%**
Deferral/Variance	kWh	2,000,000			2,000,000	$0.0004	$800.00	$800.00	
Electricity (Commodity)	kWh	2,130,200	RPP-Summer	$125,676.40	2,130,200	RPP-Summer	$125,676.40		
Transmission - Network	kWh	2,130,200	$0.0034	$7,242.68	2,130,200	$0.0034	$7,242.68		
Transmission - Connection	kWh	2,130,200	$0.0065	$13,846.30	2,130,200	$0.0065	$13,846.30		
Wholesale Market Service	kWh	2,130,200	$0.0052	$11,077.04	2,130,200	$0.0052	$11,077.04		
Rural Rate Protection	kWh	2,130,200	$0.0010	$2,130.20	2,130,200	$0.0010	$2,130.20		
Debt Retirement Charge	kWh	2,000,000	$0.0070	$14,000.00	2,000,000	$0.0070	$14,000.00		
TOTAL BILL				**$201,984.97**			**$225,595.00**	**$23,610.03**	**11.7%**