November 22, 2007

Ms. K. Walli
Board Secretary
Ontario Energy Board
Suite 2701
2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: Distribution Rate Application Board File No EB-2007-0755– Chapleau Public Utilities Corporation.

Dear Ms. Walli;

Please accept this application by Chapleau Public Utilities Corporation for new Electricity Distribution Rates, new Transmission Rates, new Distribution Loss Factors, new Low Voltage Rates and new Regulatory Asset Rates effective May 1, 2008. This completed application includes all previously submitted documents and Exhibits.

Enclosed with this letter are three (2) hard copies and an electronic version of the documents and Exhibits used to develop the 2008 Distribution Rates.

These documents have been filed on behalf of Chapleau Public Utilities Corporation.

Sincerely,

Original Signed by:

_____
Peter Ioannou
Regulatory Compliance Services

Enclosure

cc: Marita Morin, Chapleau Public Utilities Corporation.
File

17a-156 Duncan Mill Road, Toronto, Ontario M3B 3N2
416-386-0299

CHAPLEAU PUBLIC UTILITIES CORPORATION

LICENCE NO. ED-2002-0528

ADMINISTRATIVE DOCUMENTS

FOR THE FILING OF DISTRIBUTION RATE ADJUSTMENTS FOR 2008

BOARD FILE NO EB-2007-0755

COST ALLOCATION FILE NO. EB-2007-0001

EDR 2006 FILE NO.EB-2005-0349

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APPENDIX B Conditions of Service Policy

APPENDIX C Audited Financial Statements for 2006
Pro Forma Financial Statement for 2007
Pro Forma Financial Statement for 2008

APPENDIX D System Analysis for Loss Optimization

APPENDIX E Supporting (Continuity) Tables Exhibit 1 to Exhibit 9 for:

- Rate Base
- OM&A Costs
- RSVA Accounts and Rates
- Regulatory Assets Rate Riders
- Development of Rtes
- Bill Impacts

APPENDIX F Distribution System Maps

2. **Application**

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

AND IN THE MATTER OF an Application by Chapleau Public Utilities Corporation (Company) for 2008 electricity distribution rates, effective May 1, 2008, in accordance with the Ontario Energy Board's "Filing Requirements for Transmission and Distribution Applications" issued November 14, 2006.

3. **License**

Chapleau Public Utilities Corporation License Number ED2002-0528 renewed December 8, 2003 with Special License Conditions.

4. Contact Information

Key Contact:	Marita Morin Secretary -Treasurer
Mailing Address:	110 Lorne Street South P. O. Box 670 Chapleau, Ontario P0M 1K0
Phone:	705-864-0111
Fax:	705-864-1962
E-mail:	chec@onlink.net
Consultant	Peter Ioannou
Mailing Address:	156 Duncan Mill Road Suite 17A Toronto, Ontario, M3B 3N2
Phone:	416-386-0299
Fax:	416-386-0260
E-mail:	peter.ioannou@rcscanada.ca

5. Approvals Requested

Chapleau Public Utilities Corporation is seeking in the EB-2006-0170 Application for the following rate approvals:

New Distribution Rates for existing rate classes
New Retail Transmission rates
New Loss Factors
New rates for the final recovery/refund of Regulatory Assets

6. Chapleau Public Utilities Corporation does not have any Draft Issues.

Smart Metering

The Company has not included in the application any costs related to Smart Metering because the Company has not yet filed with the Board its' application for the Smart Metering Investment Program. At the present time Chapleau Public Utilities Corporation has approval to charge $0.26 per metered customer. At the present time, it is unclear how Smart Metering costs will be recovered and therefore we request to be included in any provincial mandate of Smart Metering Costs recovery..

7. There are no Procedural Orders/Motions/Correspondence.

8. The Company does not have any Accounting Orders.

9. Chapleau Public Utilities Corporation is in compliance with Uniform Systems of Accounts.

10. An electronic version for the Map of System is attached. It can be opened with "Informative Graphics (Brava DWG viewer)"

11. List of neighbouring utilities:

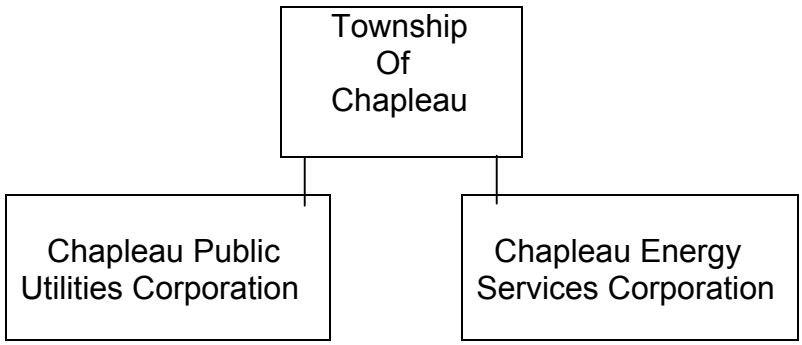
- Hydro One Networks Inc.

12. Explanation of any Host or Embedded utilities:

Chapleau Public Utilities Corporation is an embedded utility to the host, Hydro One Networks Inc.

13. Utility Organization Chart, and,

14. Corporate Entities Relationship Chart



The Township of Chapleau owns 100% of Chapleau Public Utilities Corporation and Chapleau Energy Services Corporation.

Chapleau Public Utilities Corporation (CPUC) is the local distribution company having 4 Board Members 2 of which represent the Shareholder, the Township of Chapleau. The Board and Management of the Utility reports to the shareholder annually at the Annual Shareholders meeting. The election of the Board members occurs at the Shareholders' Annual Meeting but if the Board member(s) is qualified, the Board member is eligible for reelection.

Chapleau Energy Services Corporation (CESC) is the service company having 2 Board Members 2 of which represent the Shareholder, the Township of Chapleau. The Board and Management of the Service Company reports to the shareholder annually at the Annual Shareholders meeting with the election of the Board members occurring at the Shareholders' Annual Meeting but if the Board member(s) is qualified, the Board member is eligible for reelection.

Chapleau Public Utilities Corporation and Chapleau Energy Services Corporation has an operation and maintenance service agreement between the two companies. The Utility employ's the Services Company to supply all material, labour and equipment required for new construction, repairs and maintenance of the Utility's distribution system, management support, billing and collection, rent, phone, postage and office equipment. All services are charged to the Distribution Company at direct cost plus applicable overhead (no mark-up).

A Copy of the Operation and Maintenance Service Agreement amended February 13, 2007 is attached as **Appendix A**.

15. There are no planned changes in corporate or operational structure at this time.

16. Chapleau Public Utilities Corporation has complied with all Board Directives from previous Board decisions and /or Orders.

17. There are no changes in the Policies and Regulations of the Company with respect to electricity Services from the last approved by Board.
(Changes are made to Distribution Rates periodically as approved by the OEB)

A Copy of Chapleau Public Utilities Corporation's Condition of Service Agreement effective July 1, 2004, is attached as **Appendix B**.

18 List of witnesses and their curriculum vitae will be made available if oral hearing is required

OVERVIEW

1. Summary

The **purpose** of this application is to rebase Chapleau Public Utilities Corporation' rates by applying current data with current revenue and cost requirements on a Cost Allocation basis to eliminate cross subsidization between customer classes and to develop fair and reasonable distribution rates that will allow the utility and it's customers to move forward during difficult economic times in a Northern Community.

The **timing** for rate approvals, of May 1, 2008, in this application will allow Chapleau Public Utilities Corporation (Company) to address its' revenue deficiency, its' transmission and wholesale rates that are being over-collected by approximately $115,000 per annum and apply for new low voltage rates of approximately $37,000. It will also allow the Company to refund the over-collection of Regulatory Assets that will accumulate to approximately $390,000 by April 30, 2008.

The Impact these changes will have on the typical customer and to the total Customer Class is as follows:

Typical Customer Impacts by class.

Rate Class	Consumption	Increase (Decrease)	
		$ Amount	Percent
Residential	1000 kWh	(5.69)	(4.53) %
General Service <50 kW	2000 kWh	(0.29)	(0.12) %
General Service > 50 kW	100 kW 40000 kWh	(124.09)	(2.92)%
Un-metered Scattered Load	200kWh	3.43	9.51%
Sentinel Lights	0.6 kW 222kWh	(0.14)	(0.53)%
Street Lights	2.3 kW 865 kWh	(0.17)	(0.21)%

Customer Class Impacts

The proposed changes to the Company's rates will Impact Customer Classes, based on total revenue before commodity and GST, as follows:

Customer Class	2007 Total Revenue $	2008 Total Revenue $	Variance $	Variance %
Residential	672,949	598,982	(73,966)	(10.99)
GS <50kW	191,720	186,053	(5,667)	(2.96)
GS >50kW	169,872	145,219	(24,654)	(14.51)
Un metered Scattered Load	1,278	1,547	269	21.04
Sentinel Lights	1,545	1,834	290	18.76
Street Lights	9,166	11,685	2,519	27.48
	1,046,530	945,321	(101,209)	(9.67)

2. Budget Directives.

Revenue Forecast for Bridge Year (2007) was developed using actual consumption data to May 2007 and the average of the previous two years from June to December at current approved rates. Revenue forecast for Test Year was developed using the average data for 2006 and the new forecast data developed for Bridge Year at current approved rates.

Operating and Maintenance Expenses for Bridge and Test years have been strongly influenced by prior years experience with costs being updated to reflect the impact of inflation and expected changes in costs.

Capital Budget was influenced entirely by maintenance needs and regulatory requirements (Smart Meters).

3. Economic Assumptions

Chapleau Public Utilities Corporation (Company) is a rural Northern electrical distribution company operating within the Township of Chapleau. Its' main industry is forestry having difficulty maintaining its' economic levels of the 90's and early 2000's, as seen by the reduced total consumption in kWhs of 17.1% between 2002 and 2006 and reduced population levels of 12.2% over the same period.

Consumptions by Class kWh

	Residential kWh	<50kW kWh	>50kW kWh	Total
2002	16,842,271	6,062,613	10,415,498	33,320,382
2006	14,458,522	5,457,642	7,723,163	27,639,327
Change	2,383,749	604,971	2,692,335	5,681,055
%	14.2%	10.0%	25.8%	17.1%

Population 2002	2,766
Population 2006	2,428
Change (reduction)	12.2%

Major reduction in consumption levels occurred between 2002 and 2005 stabilizing in 2006 as seen in excel worksheet Exhibit 3 (a) Op. Rev. (Data1)" in the "Customer Data section.

It must be noted that no comparisons are done based on the number of customers because most services are still connected to empty premises (to supply heat in the winter) for the Residential and GS <50kW classes.

The biggest impact to the Company was caused by the closure of commercial industrial customers in the >50kW class as follows:

In 2003 the Hotel and Restaurant (Backroads Inn) burned down and never re-opened. Their annual consumptions were 478,860kWh and 876kW with a loss of 11 jobs.

In 2004 the Grocery Store (Loebs) closed down and never reopened. Their annual consumptions were 604,800kWh and 1,152kW with a loss of 12 jobs.

In 2005 the Domtar "planer" and "dry kiln" plant (one meter) closed down for a short period of time, with the planer plant reopening for 4 months and closing down permanently in January of 2006. In May of 2006 Domtar sold the "dry kiln" plant to Tembec and are still operating today. This resulted in a net annual consumption loss of 280,160kWh and 276kW.

The biggest impact to the Township of Chapleau was the closure in 2005 of the Domtar Mill outside of town (Hydro One Customer). This was a net loss of 80 jobs between the mill, the planer and dry kiln plants.

In 2006 there was the opening of the French High school that resulted in

additional consumptions of 212,540 kWh and 780 kW.

The net consumption losses due to the above, were 1,151,280kWh (11.1% loss from the 2002 consumption level), and 1,524 kW, (6.7% loss from the 2002 consumption level).

4 The Company is not proposing changes in methodology at this time.

5 Revenue Sufficiency/Deficiency

The proposed rates will allow the Company revenue sufficiency to refund the over-collection the RSVA accounts (Regulatory Assets) that by April 30, 2008 will accumulate to $390,405 owing to customers. It will also allow the Company to adjust its' transmission rates, which are the main cause of the over-collection, to a more realistic rate that will keep the variance to a minimum.

Due to revenue sufficiency the Company will also be able to pay interest to the share holder, the Township of Chapleau. In the last 5 years the company paid the shareholder four times and arranged for the money to be given back.

By keeping the rates at the current level for 2008 it will cause a revenue deficiency with adverse effects to the Company, its' customers and shareholder. (Due to revenue deficiency the Company has not been able to pay the shareholder the interest in the amount of approximately $85,000).

Average customer consumptions by class used to develop rates for 2006, in the EDR Model, compared to the current data used to develop rates for Test Year 2008 are as follows:

Customer Class	2006 Ave. Data	2008 Ave. Data	% Change
Residential kWh	14,081	12,415	(11.8%)
GS <50kW kWh	36,122	32,994	(8.7%)
GS >50kW kWh	687,244	556,143	(19.1%)
-do- kW	1,723.7	1,512.1	(12.3%)

The current approach to develop distribution rates based on a forward test year will more accurately reflect a revenue sufficiency for the Company with applicable rates through the use of current data, 2006 to 2008, rather than the 2002 to 2004 data used to develop the company's 2006 rates (EDR Model). The Company's 2006 rates were artificially lower due to the use of the higher consumption data at a time when the Township of Chapleau experienced plant closures, reduced production and shrinking population levels (identified above).

3 Finance

1 2006 Audited Financial Statements

A Copy of Chapleau Public Utilities Corporation's Audited Financial Statements for the year ended December 31, 2006 are attached as **Appendix C**.

2 Pro Forma Statements 2007 and 2008

The following are the Pro Forma Statements (Exhibit 1 (a) Finance of the excel worksheets) together with a Cash Flow Statement, from 2007 through to the year 2012 to show the impact the refund of the Regulatory Assets the Company is proposing to make over a 4 year period and the purchase of Smart Meters in 2009 to 2012.

Exhibit 1 (a) Finance

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

Balance Sheet

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672
		-	-

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006	2006	Bridge Year	Test Year	Forecast
	Historical Board Approved	Historical Actual	2007	2008	2009
Revenue					
Distribution Revenue	$ 605,891	$ 567,925	$ 592,434	$ 680,023	$ 723,158
SSS Admin. and Retailer Charges	$ -	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,681	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	0	$ -	$ -	$ 24,631	$ 36,947
Revenue	$ 648,572	$ 611,964	$ 646,473	$ 749,633	$ 798,640
Operations and Maintenance	$ 263,311	$ 262,647	$ 296,913	$ 302,585	$ 308,637
Billing & Collecting	$ 65,879	$ 63,918	$ 66,539	$ 64,112	$ 66,035
Depreciation	$ 37,890	$ 37,370	$ 36,273	$ 36,563	$ 42,977
Administrative and General Expenses					
Community Relations	$ 2,607	$ 1,707	$ 1,063	$ 1,200	$ 1,200
Executive Salaries and Expense	$ 59,881	$ 59,331	$ 62,672	$ 64,552	$ 66,489
Office Supplies and Expense	$ 22,176	$ 19,432	$ 21,661	$ 22,248	$ 22,915
Outside Services Employed	$ 38,352	$ 47,795	$ 109,238	$ 60,820	$ 60,000
Property Insurance	$ 13,601	$ 12,119	$ 13,000	$ 13,500	$ 18,000
Regulatory Expenses	$ 5,734	$ 4,584	$ 5,769	$ 6,000	$ 12,000
Misc. General Expenses	$ 6,546	$ 10,612	$ 15,000	$ 12,000	$ 12,000
Bank Charges	$ 8,247	$ 8,941	$ 9,883	$ 9,200	$ 10,000
Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ 24,631	$ 36,947
Total Expenses	$ 524,224	$ 528,456	$ 638,011	$ 617,411	$ 657,200
Income (Loss)	$ 124,348	$ 83,508	$ 8,462	$ 132,222	$ 141,440
Interest Payable to Township of Chapleau	$ 48,454	$ -	$ -	$ 87,328	92207
Net Income (Loss)	$ 75,894	$ 83,508	$ 8,462	$ 44,894	$ 49,233

Cash Flow Forecast 2008 to 2012	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437
Net Income (Loss)	$ 8,462	$ 44,894	$ 49,000	$ 45,000	$ 45,000	$ 45,000
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (28,935)	$ (101,023)	$ (101,023)	$ (101,023)	$ (33,674)
Change in Accounts Reaceivable	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437	$ 515,654

EXHIBIT 2

Rate Base

1 Overview

Expanded Information for Rate Base, Capital Budgets and Allowance for Working Capital is included in the excel worksheet "Exhibit 2 Rate Base" in Appendix E. For each of these areas, the schedules include Historic Actual, Bridge (actual to date, balance of the year as forecasted), and Test Year.

1 Rate Base Summary

	Historic Year 2006	Bridge Year 2007	Test Year 2008
Net Fixed Assets	$909,160	$881,309	$908,647
Working Capital	$309,108	$427,090	$412,747
Rate Base	$1,298,268	$1,308,399	$1,321,394

2 Rate Base Schedule and Variance Analysis on Rate Base see **Appendix E (Exhibit 2 Rate Base)**

2 Gross Assets – Property Plant and Equipment Accumulated Depreciation and Capital Budget

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1 Continuity Statements see **Appendix E (Exhibit 2 Rate base)**

2 Gross Assets - Distribution Plant – Summary

	Opening Balance	Additions	Closing Balance
Historic Year 2006	$2,151,646	$24,292	$2,175,939
Bridge Year 2007	$2,175,939	$8,402	$2,184,341
Test Year 2008	$2,184,341	$63,861	$2,248,202

3 Analysis on Gross Asset Additions (Materiality)

Historic Year additions of $24,292 consist of the installation of 5 poles, for a total value of $1,551, installed at various times during 2006, for the replacement of old poles; The installation of 8 line transformers for a total value of $21,899, installed at various times during 2006, for the replacement of old line transformers; The installation of 3 General Service meters and 5 Residential meters for a total value of $842, installed at various times during 2006 for the replacement of old meters.

Bridge Year additions of $8,402 consist of the installation to-date of 2 line transformers and 1 pad-mount transformer for a total value of $6,902 installed between January and June 2007 for the replacement of old transformers; Install 8 poles for a total estimated value of $2,500 during the remainder of the year, October to December 2007 to replace old poles.

Test Year additions of $63,861 consist of the installation of 10 poles, for a total value of $4,000, to be installed at various times during 2008, for the replacement of old poles; The installation of 3 Regulators for a total value of $23,500, to be installed during 2008, to reduce distribution losses;
The installation of 3 line transformers for a total value of $7,000, to be installed at various times during 2008, for the replacement of old transformers; In 2008 Chapleau PUC will start its' Smart Meter program with an expenditure of $29,361 for consulting, legal etc.

There is no written policy for the capitalization of assets for Chapleau Public Utilities Corporation. Its' practice is to capitalize all distribution assets valued at or above $200.

4. Accumulated Depreciation - Distribution Plant Summary

	Opening Balance	Additions	Closing Balance
Historic Year 2006	$1,229,408	$37,370	$1,266,778
Bridge Year 2007	$1,266,778	$36,273	$1,303,051
Test Year 2008	$1,303,051	$36,563	$1,339,614

3. Allowance for Working Capital

1 Working Capital Allowance Calculations.

Chapleau Public Utilities Corporation is applying using the 15% O&M accounts formula.

	2006	2007	2008
Power Purchased	$ 1,721,671	$ 1,782,162	$ 1,751,917
WMS Charges	$ 154,628	$ 152,308	$ 153,468
Network Charges	$ 153,524	$ 147,202	$ 133,613
Connection Charges	$ 59,948	$ 51,081	$ 49,458
Low Voltage Charges	$ 13,195	$ 36,947	$ 36,947
	$ 2,102,966	$ 2,169,700	$ 2,125,403
Distribution Expenses net of Depreciation and Low Voltage	$ 491,086	$ 601,738	$ 556,217
Working Capital	$ 2,594,052	$ 2,771,438	$ 2,681,620
Allowance	15%	15%	15%
Allowance for Working Capital	**$ 389,108**	$ 415,716	$ 402,243

EXHIBIT 3

1 Operating Revenue

1 Overview

Revenue Forecast for Bridge Year (2007) was developed using actual consumption data to May 2007 and the average of the previous two years from June to December at current approved rates.

Revenue forecast for Test Year was developed using the average actual data for 2006 and the new forecast data developed for Bridge Year at current approved rates.

Load Forecast was developed using actual consumption data
Normalization Methodology (weather) has not been applied to the data.

Historical Data throughput details showing volumes, revenues, unit revenues and customer count by rate for Historical Actual, Historical Board approved, Bridge Year and Test Year is shown in excel worksheet Exhibit 3(c) Operating Revenue. The development of the Data is shown in excel worksheet **Exhibit 3(a) Op. Rev. (Data 1) and (Data 2)** in **Appendix E.**

2 Average consumption Data from excel worksheet "Exhibit 3(a) Op. Rev. (Data 1)" in Appendix E.

Year	**Residential (kWh)**	**<50kW (kWh)**	**>50kW (kWh)**	**>50kW (kW)**
2006 Approved	**14,081**	**36,122**	**687,244**	**1,723.7**
2006 Actual	**12,150**	**33,077**	**551,655**	**1,492.4**
2007 Bridge Year	**12,685**	**33,396**	**557,255**	**1,512.5**
2008 Test Year	**12,415**	**32,994**	**556,143**	**1,512.1**

3 Variance Analysis

Historical Board Approved vs. Historical Actual: Reduced customer consumptions for every customer class are mainly due to the use of historical data from 2002 to 2004 during a downturn in the economy in the Township of Chapleau. This is explained fully in Exhibit 1, 2.2.2 Overview, item 3 Economic Assumptions.

Historical Actual vs. Bridge Year: Minor variance for all classes (increase) is due to the cooler winter temperatures and the transfer in 2007 of 1 customer from the GS >50kW class to the GS <50kW class and 1 customer transfer from GS <50kW to the GS >50kW class for 2007 Bridge Year.

Bridge Year vs. Test Year: Minor variance for all classes (decrease) is due to the use of average data from 2006Actual and 2007 Bridge Year.

Variance Analysis for customer count per rate class is shown in excel worksheet Exhibit 3(a) Op. Rev. (Data 1) and (Data 2) and is fully explained in Exhibit 1 Overview, item 3 Economic Assumptions.

2 Other Revenue

1 Breakout of Other Revenue for 2006 Actual, Bridge Year and Test Year are shown in the excel worksheet **Exhibit 3(c) Operating Revenue in Appendix E**.

2 Variance Analysis

Late Payment Charges are fairly even for both 2006 Actual and 2007 Bridge Year. Test Year is determined to be the average of the two years.

Specific Service Charges for 2006 and part of 2007 were not always collected. As of August 2007 the Board of Directors of the Company authorized staff to collect all Specific Service Charges. For the 2007 Test Year, full collection of fees beginning in August will be made except for Arrears Certificate. Revenues for Test Year are calculated using the average volumes for 3 years, 2005, 2006 and 2007, at the specified service charges except for Arrears Certificate. It has recently been identified that arrears can no longer be transferred to Realty Taxes and the Company does not feel they can collect this fee upon sale of the property.

Other Revenue Sources are as follows:

Interest Earned on excess funds beyond operating funds is invested in term deposits and treasury bills and compare as follows:

	2006	2007	2008
Operating Funds	334,374	174,638	176,298
Invested	589,342	803,000	790,000
Interest Earned	12,395	16,087	15,575

Meter Exit Rebate for the two Years, $14,126.90 for 2006 and $17,100.00 for 2007 are from Hydro One. There are no further rebates from Hydro One.

Sale of Material (at a profit) comes from the recovery of costs from auto/truck accidents (mostly down poles and wires). 2008 Test Year is determined to be the average of 2006 and 2007.

Miscellaneous Revenue for 2008 Test Year is determined to be the average of 2006 and 2007.

EXHIBIT 4

1 OPERATING COSTS

1 Overview - Operating & Maintenance and Other Costs

The Company's annual Operating & Maintenance budget is determined mostly by its' revenues and the need for maintenance as required due to weather/accident related emergencies. Expanded Information for Operating & Maintenance and Other Costs is included in the excel worksheet "**Exhibit 3(a) Op. Rev. (Data 1)" in Appendix E**.

2 Operating Cost Summary

Year	Amount
2006 Board Approved	$ 263,311
2006 Actual	$ 262,647
2007 Bridge Year	$ 296,913
2008 Test Year	$ 302,585

The Company's distribution system expenditures to September 30, 2007 are $247,266 with the expectation to spend an additional $55,319 to the end of December 2007.

The Company expects to spend the equivalent amount during the Test Year, 2008, and is allowing for an increase of 3% for salaries, wages and cost of material. Overall increase is 1.9% from 2007. Please note that the increase of 3% for salaries and wages in January, 2008 is to match the increase (existing) in the collective bargaining agreement between the Township of Chapleau and its' employees.

2 OM & A Costs

1 OM & A Costs Table - see excel worksheet "**Exhibit 4 Operating Costs" in Appendix E**.

2 Variance Analysis - see excel worksheet "**Exhibit 4 Operating Costs" in Appendix E**.

3 Distribution Expense through Purchase of Services Summary

Year	Amount
2006 Actual	$ 47,795
2007 Bridge Year	$ 109,238
2008 Test Year	$ 60,820

Bridge Year expenditures to September 30, 2007 are $63,238 with the expectation to spend an additional (total) $46,000 for a 3 year business plan being prepared by our auditors, KPMG and for the filing of a Cost of Service Rate Application based on a forward test year being prepared by Regulatory Compliance Services.

Price determination for the purchase of services is determined as follows:

For local contractors, if more than one is available, through the (informal) issue of a Request For Proposal (RFP) and is awarded based on ability to perform at the lowest price. As for the rest, there are limitations as to service availability requiring expert knowledge of our business, including regulatory issues, where we negotiate a price before proceeding.

4 Shared Services

Expenditure for all shared services, between the Distribution Company and the Service Company, is determined by the direct hours being charged (performed) to each Company.

Shared services are:

Service	Charge Determination
Manpower	Direct charge (hours)
Material	Direct charge (material)
Building Space	% of direct hours charged to total hours
Computers	% of direct hours charged to total hours
Furnishings	% of direct hours charged to total hours
Benefits	% of direct hours charged to total hours
Vehicles	% of direct hours charged to total hours
Insurance	% of direct hours charged to total hours
Utilities (phone, hydro, etc.)	% of direct hours charged to total hours

5 Manpower – Employee Description

The Distribution Company (CPUC) does not have any employees. It contracts all the work to the Service Company (CESC) which employs the following:

1 Management
1 Clerical
3 Line Persons
1 Summer Student
All are non unionized positions.

	2006 Compensation	2006 Benefits	2007 Compensation	2007 Benefits	2008 Compensation	2008 Benefits
Charges from CESC to CPUC	$197,120	$74,432	$213,331	$84,672	$219,676	$84,994
Share - CPUC	71.6%	71.6%	74.7%	74.7%	74.7%	74.7%
Share - CESC	28.4%	28.4%	25.3%	25.3%	25.3%	25.3%

Salaries, Wages and benefits for the 5 full time employees and the summer student have been grouped together for confidentiality reasons.

Pension from May 1, 2006 to December 31, 2006 has been erroneously allocated to a deferral account instead of an expense account thus requiring an adjustment to the Company's distribution expenses. This will be adjusted in 2007 to correct the error.

6 Benefit Programs

Benefit Programs consist of the following:

Holiday and Sick Time Pay
Group Insurance (Health, Dental, Life, etc)
WSIB expense
CPP expense
EI Expense
Extended Health Tax
OMERS pension plan

7 Depreciation/Amortization/Depletion

Depreciation rates will not change in 2008

Provision for Depreciation, Amortization and Asset Additions for Historic and Board Approved, Bridge Year and Test Year are shown in excel worksheet "Exhibit 2 Rate Base".

8 Loss Adjustment Factor Calculation

Average Line Losses for the Years 2003 to 2007 are determined to be **1.0565%** as follows:

	Wholesale kWh	Retail kWh	Loss Factor
2003	**33,611,224**	**32,484,068**	**1.0347**
2004	**32,654,946**	**30,980,687**	**1.0540**
2005	**31,058,652**	**29,014,570**	**1.0705**
2006	**29,569,274**	**27,963,997**	**1.0574**
2007	**30,316,796**	**28,437,687**	**1.0661**
Average Loss Factor			**1.0565**

The loss factor as calculated above is recommended as the new loss factor for 2008.

Expanded Information for the development of data for 2007 is included in the excel worksheet **"Exhibit 3(a) Op. Rev. (Data 1)" in Appendix E**.

As an imbedded Utility to Hydro One Networks Inc., Hydro One's loss factor of 1.0350 is applied to the Company's wholesale purchases from the IMO, which is part of the Company's average loss factor of 1.0565, for which the Company has no control over. The Company realized the total loss factor is over 5% and has undertaken a "System Analysis for Loss Optimization" study to identify the reason for these losses (the study is attached for the Boards' information **as Appendix D**.).

The reports' recommendations are as follows:

- *Address voltage adequacy issues at the peak period through the proposed open point reconfiguration, phase rebalancing and new line voltage regulator interventions.*

- *Consider using TRC analysis of proposed Phase II capacitor installations performed by EnerSpectrum Group in order to meet year end OEB reporting requirements.*

- *With assistance from EnerSpectrum Group, Chapleau PUC. pursue risk mitigation measures identified in the Risk/Mitigation/Residual Risk table to confirm the results of this study and to improve the accuracy and reliability of future studies.*

- *To maintain a viable loss profile, and accurate system models for planning and operational purposes, it is recommended that the systems be evaluated on 3-5 year routine.*

Based on the reports' recommendations and discussions with EnerSpectrum Group engineers, Management and the Board of Chapleau Public Utilities Corporation have recommended to spend in 2008 $23,500 in capital expenditures for the purchase and installation of 3 regulators, $10,000.00 for 2 Capacitors, under the CDM program, and contact the larger commercial customers, in the >50kW class, who's power factors requires improvement, to offer advice (educate) on how to improve their power factor and realize cost savings through the use of capacitors and load shifting.

3 Income Tax, Large Corporation Tax and Ontario Capital Taxes

Due to corporate losses to December 31, 2006 of $728,423 the Company does not expect to pay taxes (PILs) in the near future. These losses will expire as follows:

2010	$128,130
2011	$296,896
2012	$303,397

EXHIBIT 5

Deferral and Variance Accounts

1 1 Status of RSVA and non-RSVA Related Deferral and Variance Accounts.

Following the 2006 EDR rate setting process, the Company erroneously recorded its' Pension Costs and OEB Cost Assessment in deferral account 1508 beyond May 1, 2006. Pension Costs and OEB Cost Assessment have been included in the 2006 Rates, developed through the EDR Model, and should have been expensed from May 1, 2006 to December 31, 2006. This deferral account will be adjusted in 2007 to correct the error.

Following the above adjustment the status of RSVA and non-RSVA Related Deferral and Variance Accounts are shown in the expanded excel worksheets **"Exhibit 5(a) RSVA Variances", "Exhibit 5(b) RSVA accounts" and "Exhibit 5(c) Regulatory Assets" in Appendix E.**

2 Description of Deferral and Variance accounts:

Account Number	Description
1580	RSVA Wholesale Market Service Charge
1582	RSVA Retail Transmission Network Charge
1584	RSVA Retail Transmission Connection Charge
1586	RSVA Power
1550	Low Voltage Charges
1508	Other Reg. Assets - Pension
1508	Other Reg. Assets – OEB Cost Assessment

3 Calculations and Variances

Variance Analysis - see excel worksheet **"Exhibit 5(a) RSVA Variances" in Appendix E**.

All RSVA accounts, 1580, 1582, 1584 and 1586 show the difference between amounts paid vs. amounts collected, for each account, from all customers and applying interest at the prescribed rate on the (opening) balance outstanding, on a monthly basis to April 30, 2008.

The Variance for Low Voltage Charges, account 1550, is calculated to April 30, 2008, as this cost has not been applied to the 2006 EDR Rates. Interest has also been applied on the opening balance at the prescribed rate on a monthly basis to April 30, 2008.

The Variance for Pension and OEB Cost Assessment, in account 1508, is only applicable to April 30, 2006 as these costs have been applied to the 2006 EDR Rates. Interest has been applied on the opening balance at the prescribed rate on a monthly basis to April 30, 2006.

Adjustment has also been made to transmission costs to account for the 12% reduction effective November 1, 2007, as advised by the OEB, and variances adjusted accordingly.

4 Summary of Variances is shown in excel worksheet **"Exhibit 5(b) RSVA Accounts" in Appendix E**.

Over the last few years there has been an over collection of the RSVA and non-RSVA Related Deferral and Variance Accounts that by April 30, 2008 will accumulate to a credit of $404,093.03 that will be owing to customers. The main cause of the over collection is mainly due to the Transmission Connection Charge being $336,788.57.

The purpose of this worksheet is to develop adjusted rates for all RSVA accounts and to develop a new Low Voltage rate beginning May 1, 2008.

To develop Costs and Revenues for all RSVA and Low Voltage accounts, actual Costs and Revenues were used to September 2007 and estimated monthly average of the previous 2 Years for the period October 2007 to December 2007. Costs and Revenues for 2008 were developed using the monthly average of 2006 and 2007.

Adjustment has been made to transmission costs to account for the 12% reduction effective November 1, 2007, as advised by the OEB on October 29, 2007.

5 Calculation of new RSVA rates

New RSVA rate calculations are shown in excel worksheet **"Exhibit 5(b) RSVA Accounts" in Appendix E**.

New calculated Rates for Network, Connection and Wholesale were calculated using the average of 3 years 2006, 2007 and 2008.

Calculated rates for Low Voltage charges were calculated using the 12 months actual cost from August 2006 to July 2007 of $36,946.56 and the average consumptions of 2006, 2007 and 2008 from excel worksheet **"Exhibit 3 (a) Op. Rev. (Data 1)" in Appendix E.**

6 Regulatory Assets - Summary

All Regulatory Asset Variances and Rate Riders are shown in excel worksheet **“Exhibit 5(c) Regulatory Assets in Appendix E**.

The purpose of this worksheet is to develop Rate Riders to refund and/or collect variances for all RSVA and non-RSVA Related Deferral and Variance Accounts.

The total variance for RSVA and non-RSVA Related Deferral and Variance Accounts by April 30, 2008 will accumulate to a credit of $404,093.03 (owing to customers). The main cause of the over collection is mainly due to the Transmission Connection Charge being a credit of $336,788.57.

This worksheet summarizes all Variances and apportions them to all customer classes using the Estimated Consumptions for each customer class for 2008 from **"Exhibit 3(a) Op. Rev. (Data 1)” in Appendix E.**

The Company is unable to refund all the variances, totaling $404,093.03, in one year. In order for the Company, not to be put at (financial) risk, the Company is proposing to refund these variances over a 4 year period ($101,023.26 annually) commencing May1, 2008 and ending April 30, 2012. Please refer to the cash flow forecast in excel worksheet **“Exhibit 1 Finance” in Appendix E.**

EXHIBIT 6

Cost of Capital and Rate of Return

1 Capital Structure – Amounts and Ratios

1 Overview

The excel worksheet **"Exhibit 6 Cost of Capital and ROR" in Appendix E** shows the elements required for Current Board Approved, Historical Year's Actual, Bridge Year and Test Year.

2 Capital Structure

The Company's requirement to move toward the structure of 60% Debt and 40% Equity by the year 2010, as required by the Ontario Energy Board, necessitated the following proposed structure of the Company for the 2008 Test Year:

Long-Term Debt	$1,195,551	53.3%
Short-Term Debt/Unfunded Debt	$ 0	0.0%
Total Debt	$1,195,551	53.3%
Preference Shares	$ 0	0.0%
Common Equity	$ 1,047,509	46.7%
Total Equity	$ 1,047,509	46.7%
Total Rate Base	$ 2,243,060	100.0%

Calculation of Return on Equity and Debt

	Deemed Portion	Effective Rate	Average Cost of Capital
Total Debt	53.3%	7.25%	3.87%
Total Equity	46.7%	9.00%	4.20%
Weighted Average Cost of Capital			8.07%

EXHIBIT 7

Calculation of Revenue Deficiency or Surplus

1 Determination of Net Utility Income and Rate Base is shown in the expanded excel worksheet **"Exhibit 7 Revenue Deficiency or Surplus" in Appendix E.**

The company's net Utility Income (summarized) is as follows:

Revenue		$ 749,633
Expenses		
Operations & Maintenance	$ 366,697	
Depreciation	36,563	
Administration	189,520	
Low Voltage Charge	24,631	$ 617,411
Utility Income		$ 132,222

Proposed Rate Base	$ 1,311,805
Required Return at 8.07%	$ 105,863
Actual Return 10.08%	$ 132,222
Revenue Surplus	$ 26,359

The Company requests that Net Utility Income be $132,222 or 10.8%

EXHIBIT 8

Cost Allocation

1 Overview

1 The results that were produced by the Cost Allocation process proposed changes to customer class distribution revenues that would be comparable to the cost ratios allocated by the process. These percentages show the customer classes that are being subsidized (being under 100%) or those that are over contributing (being over 100%).

Results Summary (CA Model Run 2)

	Revenue to Cost Ratio	**$ Over Contributing $ (Subsidized)**
Residential	113.51%	55,035
GS <50kW	91.37%	(11,199)
GS >50kW	78.79%	(14,819)
Un metered Scattered Load	78.67%	(458)
Sentinel Lights	45.37%	(1,334)
Street Lights	17.39%	(27,226)

The monthly fixed charge produced by the CA model for each rate classification was compared to the approved monthly service charge for that period and compares as follows:

	Avoided Cost Charge	**Directly Related Charge**	**Minimum System Charge**	**2006 Approved Fixed Charge (EDR Model)**
Residential	3.68	6.34	12.99	19.74
GS <50kW	8.75	15.26	20.32	30.89
GS >50kW	26.01	48.18	45.13	151.53
Un metered Scattered Load	11.13	20.41	23.27	15.32
Sentinel Lights	0.22	0.42	8.35	2.63
Street Lights	0.01	0.01	8.05	0.79

These fixed charge results produced are based on 3 scenarios, Avoided Costs, Directly Related Costs and Minimum System Approach.

For Avoided Costs, only billing, collection and meter related costs are included.

For Directly Related Costs, only costs included in the Avoided Costs method plus an allocation of administration and overhead costs are included.

The Minimum System Approach assumes minimum load requirements at 400 watts per customer using the minimum size pole, conductor, cable, transformer and service that the distributor currently uses.

2 Results and Proposed changes

Based on the above results, which are primarily presented in the Revenue to Cost ratios, Chapleau Public Utilities Corporation is prepared to accept that there is cross subsidization between all customer classes and is prepared to make these adjustments to Residential and General Service <50 kW and >50 kW, and partial adjustments to Un metered Scattered Load Sentinel Lights and Street Lights provided customer impacts are kept to a minimum.

Based on the revenue requirement for the 2008 Test Year the Company is proposing to make the following adjustments to reduce/eliminate cross subsidization:

	Test Year Revenue Requirement $	**$ Over Contributing $ (Subsidized)**	**Adjusted Test Year Revenue Requirement $**
Residential	494,842	(32,221)	462,621
GS <50kW	125,924	12,714	138,638
GS >50kW	59,244	15,397	74,640
Un metered Scattered Load	1,357	130	1,487
Sentinel Lights	1,170	480	1,650
Street Lights	5,982	3,500	9,982
	688,519	0.00	688,519

As for the monthly fixed charge rate, the Company is prepared to make the following adjustments as calculated in excel worksheet **"Exhibit 9 (b) CA Rate Design" in Appendix E**.

	2007 Approved Fixed Charge Rate $	**Proposed Fixed Charge Rate $**
Residential	19.92	21.82
GS <50kW	31.17	39.99
GS >50kW	152.82	223.14
Un metered Scattered Load	15.48	19.61
Sentinel Lights	2.65	4.33
Street Lights	0.80	1.47

EXHIBIT 9

Rate Design

1 EXISTING RATE CLASSES

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively by a single family unit, non-commercial. This can be a separately metered living accommodation, town-house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning.

General Service less than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Un-metered 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 un-metered. 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 refers 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.

2 EXISTING RATE SCHEDULE

Residential UOM Rate		
Service Charge	$	19.92
Distribution Volumetric Rate	$/kWh	0.0100
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
General Service less 50kW		
Service Charge	$	31.17
Distribution Volumetric Rate	$/kWh	0.0085
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
General Service 50 to 4999 kW		
Service Charge	$	152.82
Distribution Volumetric Rate	$/kW	1.2099
Regulatory Asset Recovery	$/kW	(0.2732)
Retail Transmission Rate – Network Service Rate	$/kW	1.8304
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7882
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Unmetered Scattered Load		
Service Charge	$	15.46
Distribution Volumetric Rate	$/kWh	0.0085
Regulatory Asset Recovery	$/kWh	(0.0001)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Sentinel Lighting		
Service Charge	$	2.65
Distribution Volumetric Rate	$/kW	3.7484
Regulatory Asset Recovery	$/kW	3.0482
Retail Transmission Rate – Network Service Rate	$/kW	1.3874
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4113
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Street Lighting		
Service Charge	$	0.80
Distribution Volumetric Rate	$/kW	2.4286
Regulatory Asset Recovery	$/kW	0.0178
Retail Transmission Rate – Network Service Rate	$/kW	1.3804
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3824
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Specific Service Charges

Customer Administration

Arrears certificate	**$**	**15.00**
Credit reference/credit check (plus credit agency costs)	**$**	**15.00**
Returned cheque charge (plus bank charges)	**$**	**15.00**
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	**$**	**30.00**
Special meter reads	**$**	**30.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	**$**	**30.00**
	$	0.00

Non-Payment of Account

Late Payment - per month	**%**	**1.50**
Late Payment - per annum	**%**	**19.56**
Collection of account charge - no disconnection	**$**	**30.00**
Disconnect/Reconnect at meter - during regular hours	**$**	**60.00**
	$	0.00

Install/Remove load control device - during regular hours	**$**	**65.00**
Specific Charge for Access to the Power Poles $/pole/year	**$**	**22.35**
	$	0.00

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**
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	**1.0497**
Total Loss Factor – Secondary Metered Customer > 5,000 kW	**1.0145**
Total Loss Factor – Primary Metered Customer < 5,000 kW	**1.0392**
Total Loss Factor – Primary Metered Customer > 5,000 kW	**1.0045**

3 PROPOPSED RATE CLASSES

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively by a single family unit, non-commercial. This can be a separately metered living accommodation, town-house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning.

General Service less than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW
This classification applies to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Un-metered 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 un-metered. 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 refers 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.

4 PROPOSED RATE SCHEDULE

Residential UOM Rate		
Service Charge	$	21.82
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
General Service less 50kW		
Service Charge	$	39.99
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
General Service 50 to 4999 kW		
Service Charge	$	223.14
Distribution Volumetric Rate	$/kW	2.2455
Regulatory Asset Recovery	$/kW	(1.3205)
Retail Transmission Rate – Network Service Rate	$/kW	1.6236
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6724
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Unmetered Scattered Load		
Service Charge	$	19.61
Distribution Volumetric Rate	$/kWh	0.0121
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Sentinel Lighting		
Service Charge	$	4.33
Distribution Volumetric Rate	$/kW	6.5934
Regulatory Asset Recovery	$/kW	(1.2956)
Retail Transmission Rate – Network Service Rate	$/kW	1.2307
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5307
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25
Street Lighting		
Service Charge	$	1.47
Distribution Volumetric Rate	$/kW	4.9518
Regulatory Asset Recovery	$/kW	(1.3551)
Retail Transmission Rate – Network Service Rate	$/kW	1.2245
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5198
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Specific Service Charges

Customer Administration

Arrears certificate	**$**	**15.00**
Credit reference/credit check (plus credit agency costs)	**$**	**15.00**
Returned cheque charge (plus bank charges)	**$**	**15.00**
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	**$**	**30.00**
Special meter reads	**$**	**30.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	**$**	**30.00**
	$	0.00

Non-Payment of Account

Late Payment - per month	**%**	**1.50**
Late Payment - per annum	**%**	**19.56**
Collection of account charge - no disconnection	**$**	**30.00**
Disconnect/Reconnect at meter - during regular hours	**$**	**60.00**
	$	0.00

Install/Remove load control device - during regular hours	**$**	**65.00**
Specific Charge for Access to the Power Poles $/pole/year	**$**	**22.35**
	$	0.00

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**
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	**1.0613**
Total Loss Factor – Secondary Metered Customer > 5,000 kW	**1.0145**
Total Loss Factor – Primary Metered Customer < 5,000 kW	**1.0506**
Total Loss Factor – Primary Metered Customer > 5,000 kW	**1.0045**

5 Customer Class Impacts - Summary.

The proposed changes to the Company's rates will Impact Customer Classes, based on total revenue before commodity (Cost of Power) and GST, as follows:

Customer Class	2007 Total Revenue $	2008 Total Revenue $	Variance $	Variance %
Residential	672,949	598,982	(73,966)	(10.99)
GS <50kW	191,720	186,053	(5,667)	(2.96)
GS >50kW	169,872	145,219	(24,654)	(14.51)
Un metered Scattered Load	1,278	1,547	269	21.04
Sentinel Lights	1,545	1,834	290	18.76
Street Lights	9,166	11,685	2,519	27.48
TOTAL	**1,046,530**	**945,321**	**(101,209)**	**(9.67)**

The proposed changes to the Company's rates consist of the following items:

	2007 Total Revenue $	2008 Total Revenue $	Revenue Change $	Percent Change
Rate Base - Volumetric charge	220,513	258,790	38,278	17.4%
Rate Base - Service charge	370,031	429,729	59,698	16.1%
- Smart Meter Rate	4,234	4,234	0.0	0%
Low Voltage Rate	0.0	36,903	36,903	N/A
Wholesale Market Rate and Rural Rate	174,845	144,573	(30,272)	(17.3%)
Transmission Rates (Connection and Network)	272,773	172,115	(100,658)	(36.9%)
Regulatory Assets	4,135	(101,023)	(105,158)	(2543.4%)
TOTAL	**1,046,530**	**945,321**	**(101,209)**	**(9.7%)**

6 Detailed Class and Customer Impacts and Mitigation

Residential

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	19.92	21.82	9.5
Volumetric Charge	0.0100	0.0121	21.0
Regulatory Asset Rate	0.0007	(0.0036)	>(500.0)
Transmission - Network	0.0049	0.0043	(12.2)
Transmission - Connection	0.0050	0.0019	(280.0)
Wholesale Market Rate	0.0052	0.0041	(21.2)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that there are no customers that will be impacted by more than 10%. A typical size customer consuming 1000kWh per month will experience a reduction in their monthly bill of $5.69 or 4.53%.

General Service <50kW

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	31.17	39.99	28.3
Volumetric Charge	0.0085	0.0121	42.4
Regulatory Asset Rate	(0.0001)	(0.0036)	>(500.0)
Transmission - Network	0.0045	0.0040	(11.1)
Transmission - Connection	0.0045	0.0017	(277.8)
Wholesale Market Rate	0.0052	0.0041	(21.2)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that there are 21 customers consuming less than 412kWh per month that will be impacted by more than 10%. Some of these premises are vacant with little or no consumption. These customers will experience monthly increases of between $9.35 and $7.37 or 10.01% to 28.30%. To mitigate the impact to these customers the Company will make adjustments to the rates by reducing the service charge for 6 months to October 30, 2008 from $39.99 to $35.60 per month. This will reduce the Company's distribution revenue by $553.14.
A typical size customer consuming 2000kWh will experience a reduction in their monthly bill of $0.29 or 0.12%.

General Service >50kW

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	152.82	223.14	46.0
Volumetric Charge	1.2099	2.2455	102.1
Regulatory Asset Rate	(0.2732)	(1.3205)	(383.3)
Transmission - Network	1.8304	1.6236	(11.3)
Transmission - Connection	1.7882	0.6224	(65.2)
Wholesale Market Rate	0.0052	0.0041	(26.8)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that there are no customers that will be impacted by more than 10%. A typical size customer consuming 40,000kWh and 100kW per month will experience a reduction in their monthly bill of $124.09 or 2.92%.

Un-metered Scattered Load

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	15.46	19.61	26.8
Volumetric Charge	0.0085	0.0121	42.4
Regulatory Asset Rate	(0.0001)	(0.0036)	>(500.0)
Transmission - Network	0.0045	0.0040	(11.1)
Transmission - Connection	0.0045	0.0017	(62.2)
Wholesale Market Rate	0.0052	0.0041	(26.8)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that all 6 customers will be impacted by more than 10%. Consumptions for these customers range between 16kWh to 180kWh per month and will experience increases of between $3.53 and $4.32 or 10.34% to 24.05%. To mitigate the impact to these customers the Company will make adjustments to the rates by reducing the service charge for 6 months to October 30, 2008 from $19.61 to $17.54 per month. This will reduce the Company's distribution revenue by $ 74.52.

Sentinel Lighting

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	2.65	4.33	63.4
Volumetric Charge	3.7484	6.5934	75.9
Regulatory Asset Rate	3.0482	(1.2956)	(325.0)
Transmission - Network	1.3874	1.2307	(11.3)
Transmission - Connection	1.4113	0.5307	(62.4)
Wholesale Market Rate	0.0052	0.0041	(26.8)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that there are 2 customers that will be impacted by more than 10%. Consumptions for these customers is below 81kWh per month and will experience maximum increases of up to $1.15 or 11.44% per month. Based on the identified range of impacts, Chapleau Public Utilities Corporation does not intend to override the calculated rates to mitigate impacts.
The typical size customer consuming 222kWh will experience a reduction in their monthly bill of $0.14 or 0.53%.

Street Lighting

Customer Class	Approved 2007 $	Proposed 2008 $	% Variance
Service Charge	0.80	1.47	83.8
Volumetric Charge	2.4286	4.9518	103.9
Regulatory Asset Rate	0.0178	(1.3551	>(500.0)
Transmission - Network	1.3804	1.2245	(11.3)
Transmission - Connection	1.3824	0.5198	(62.4)
Wholesale Market Rate	0.0052	0.0041	(26.8)
Rural Rate Protection Rate	0.0010	0.0010	0
Regulated Price Plan	0.2500	0.2500	0
Debt Retirement Charge	0.0700	0.0700	0

It has been determined that there are no customers that will be impacted by more than 10%. There is only one customer and 341 connections for streetlights. Based on the average monthly consumption 24,500kWh and 65.0kW the monthly bill will increase $217.11 or 7.61%.

Appendix A

AMENDED FEBRUARY 13, 2007

THIS OPERATION AND MAINTENANCE SERVICES AGREEMENT (hereinafter referred to as the "Agreement") is entered into as of January 1, 2002.

B E T W E E N :

CHAPLEAU PUBLIC UTILITIES CORPORATION, a corporation incorporated pursuant to the provisions of the laws of Ontario, having its registered head office in the corporation of the Township of Chapleau in the District of Sudbury.

OF THE FIRST PART
(hereinafter referred to as the **Corporation").**

-and-

CHAPLEAU ENERGY SERVICES CORPORATION, a corporation incorporated pursuant to the provisions of the laws of Ontario, having its registered head office in the corporation of the Township of Chapleau in the District of Sudbury.

OF THE SECOND PART
(hereinafter referred to as the **"Affiliate").**

WHEREAS:

(1) The Corporation is an electricity distributor and transmitter;

(2) Not withstanding the articles of incorporation the Affiliate is a corporation incorporated to permit among other things, the sale of related services and is wholly owned by the same share holder as the corporation, and is in the business of providing staffing, operation and maintenance services to corporations and other entities operating electrical or telecommunications facilities;

(3) The Corporation shares services or resources with the Affiliate, it shall do so in accordance with this Agreement; and

(4) It is a condition precedent for the sharing of services or resources that the Corporation and the Affiliate enter into this Agreement pursuant to the *Affiliate Relationships Code for Electricity Distributors and Transmitters* effective April 1, 1999.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained

herein, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, **IT IS AGREED:**

a. Service

The Affiliate will provide services to the Corporation in respect to the staffing operations and maintenance of the Corporation's operations in accordance with this Agreement comprising the Services, throughout the Term.

b. Duties and Responsibilities of the Affiliate

(a) The Affiliate shall have the duties and responsibility during the Term to administer, operate and maintain the Corporation's operations, including without limitation providing the necessary staff to provide the Services to the Corporation. Without limiting the generality of the foregoing, the Affiliate shall have the following duties and responsibilities:

(i) to prepare an annual budget for the performance of the Services by the Affiliate and to submit such Operating and Maintenance Plan to the Corporation for its approval for the 2002 fiscal year by May 31, 2002 and for subsequent fiscal years at least 30 days prior to the beginning of each fiscal year;

(ii) to provide the services of trained and licensed (where applicable) Affiliate personnel to provide the Services to the Corporation and otherwise meet the Affiliate's obligation under this Agreement (the "Operations Staff");

(iii) to assist the Corporation in obtaining and maintaining and fulfilling all necessary permits, consents and permissions, or other regulatory requirements related to the Services, including any licensing requirements pursuant to the OEB act;

(iv) to use its reasonable efforts to secure and maintain from vendors, suppliers and subcontractors the best indemnities, warranties and guarantees as may be commercially available regarding all supplies, equipment and services purchased in relation to the Services, all of which shall be assigned to the Corporation, and assist the Corporation in preserving and enforcing such indemnities, warranties or guarantees;

(v) to promptly notify the Corporation of:

(1) any default hereunder;

(2) any condition or occurrence which is likely to result in a material difference in the Operating and Maintenance Expenses and/or the schedule of operations as projected in the Operating and Maintenance plan;

(3) any occurrence, accident, safety violation, lawsuit claim by any person which might reasonably be expected to result in an investigation or penalty under applicable laws or any material violation of any applicable laws; or

(4) any other event which might reasonably be expected to have a material adverse effect on the services;

(b) it shall provide the staff and resources that are sufficient for the area serviced by the Affiliate;

(c) it shall, where applicable, provide and maintain the quality of Service provided by the Affiliate at least equal to the service levels required by the Ontario Energy Board ("OEB") for the term of the Agreement and which are comparable to the service and reliability levels enjoyed by customers of the Corporation; and

(d) it shall make all necessary filings and reports to the OEB with respect to the levels of services as the OEB may require from time to time.

1.3 Failure to Maintain Service Levels

In the event the Affiliate fails to maintain Service at levels referred to in Section 1.1 during the term of this Agreement:

(a) the Corporation shall be entitled to retain a qualified professional to review and analyse all records and reports of the Affiliate to determine proper service levels are being met; and

(b) the Corporation and the Affiliate shall meet to discuss remediation and agree, acting reasonably, on the appropriate course of action to be taken by the Affiliate.

1.4 Appointment of Risk

In the case of any actions that may arise during the course of this Agreement, each of the Corporation and the Affiliate shall:

(a) indemnify, defend and save harmless the other from all fines, suits, proceedings, liabilities, losses, damages, costs, expenses, claims, demands or actions of any nature or kind whatsoever caused directly or indirectly related to its assets or operations which are the subject of this Agreement through a failure of either party to fully its obligations under this Agreement;

(b) be individually responsible for all liability which results from:

a. the operations of the Corporation or the Affiliate; or

b. any products, goods or materials brought onto the property or used by the Corporation or the Affiliate.

2. Conduct of Work

In connection with the terms of this Agreement, each of the Corporation and the Affiliate shall ensure:

(a) their respective employees, agents, contractors and subcontractors are duly qualified under any applicable federal and provincial laws; and

(b) that all work performed by their respective employees, agents, contractors and subcontractors are in compliance with any applicable federal and provincial laws.

3. Pricing

(a) where the Corporation provides the Service or shares a resource with the Affiliate, the Corporation shall ensure that the sale price is no less than the fair market value of the service or resource;

(b) in obtaining a Service or resource from the Affiliate, the Corporation shall pay no more than the fair market value of the service or resource, and

(c) where a fair market value is not available for any Service or resource, the cost-based price of producing the service or resource shall be used.

(d) Cost-based price shall be determined by allocating the actual cost of the Service or shared resource to the Affiliate and the Corporation.
The allocation of cost shall be based upon direct labour hours utilized by the Affiliate and the Corporation, as calculated quarterly.

(e) To assist in the cash flow of the Affiliate, the Corporation shall advance on a monthly basis, the estimate cost of those shared Services or resources.

(f) Once the direct labour hours have been apportioned for a quarter, the actual cost of services and shared resources shall be allocated between the Affiliate and the Corporation.

(g) It is agreed by the Corporation and the Affiliate, that the above cost allocation formula will be reviewed on a semi-annual basis. Amendments of the formula will be made as determined appropriate by mutual agreement of the Affiliate and the Corporation.

4. Confidentiality

In connection with terms of this Agreement, the Affiliate shall execute and deliver in favour of the Corporation a confidentiality agreement substantially in the form attached hereto as Schedule A and be bound by such an agreement as a condition of undertaking the activities referred to in this Agreement.

5. Dispute Resolution

(a) Any dispute, controversy or claim arising out of or in connection with, or relating to, this Agreement, or the performance, breach or validity thereof, shall be settled by arbitration. Either party may initiate arbitration within a reasonable time after such dispute, controversy or claim has arisen by delivering a written demand for arbitration upon the other Party. The arbitration shall be conducted in accordance with the Arbitration Act. The arbitration shall take place in Chapleau, Ontario, and shall be conducted in English.

(b) The arbitration shall be conducted by a single arbitrator having no financial or personal interest in the business affairs of either of the Parties. The arbitrator shall be appointed jointly by agreement of the Parties, failing which an arbitrator shall be appointed by application to the Superior Court of Ontario, in Sudbury.

(c) Absent agreement or an award in the arbitration to the contrary, the arbitrations fees and expenses shall be paid by the Parties jointly, and

(d) The arbitral award shall be in writing, stating the reasons for the award and be final and binding on the Parties with no rights of appeal. The award may include an award of costs, including reasonable legal fees and disbursements and fees and expenses of the arbitrator. Judgment upon the award may be entered by any court having jurisdiction thereof or having jurisdiction over the Parties or their assets.

(e) Confidentiality of Arbitration – The arbitration shall be kept confidential and the existence of the proceedings and any element of it (including but not limited to any pleadings, briefs or other documents submitted and exchanged, and testimony or other oral submission and any awards) shall not be disclosed beyond the arbitrator, the Parties, their counsel and any other person necessary to the conduct of the proceedings, except as may be lawfully required in judicial proceedings relating to the arbitration or otherwise.

6. Applicable Law

This agreement shall be constructed, interpreted and enforced in accordance with, and the respective rights and obligations of the parties shall be governed by, the laws of the Province of Ontario and the federal laws of Canada applicable therein, and each party irrevocably and unconditionally submits to the non-exclusive jurisdiction of the court of such province and all court competent to hear appeals therefrom.

7. Severability

If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination shall not impair or affect the validity, legality or enforceability of the remaining provisions hereof, and each provision is hereby declared to be separate, severable and distinct.

8. Amendments and Waivers

No amendment or waiver of any provision of this Agreement shall be binding unless consented to in writing. No waiver of any provision of this Agreement shall constitute a waiver of any other provision, nor shall any waiver constitute a continuing waiver otherwise provided.

9. Term

The term of this Agreement shall commence upon the date of execution hereto for a period of two (2) years. The Corporation shall have a right in its sole discretion to renew this Agreement no later than six (6) months from the end of the term for an additional period of two (2) years.

10. Time of the Essence

Time shall be of the essence.

11. Counterparts

This Agreement may be executed in two or more counterparts, each of which shall be deemed to be an original and all of which together shall constitute on and the same agreement.

IN WITNESS WHEREOF this Agreement has been executed by the Parties as of the date first above written

Signed, sealed and delivered in the presence of:

Per: Chapleau Public Utilities Corporation

_____
Authorized signing officer
I have authority to bind the Corporation

Per: Chapleau Public Utilities Corporation

_____
Authorized signing officer
I have authority to bind the Corporation

Per: Chapleau Energy Services Corporation

_____
Authorized signing officer
I have authority to bind the Corporation

Per: Chapleau Energy Services Corporation

_____
Authorized signing officer
I have authority to bind the Corporation

Schedule A

Confidentiality Arrangements. Pursuant to the Affiliate Relationships Code, the Parties hereby agree to establish and maintain the following confidentiality arrangements:

1. The Corporation shall not release to the Affiliate confidential information relating to a consumer, retailer or generator without the consent of that consumer, retailer, or generator.

2. The Corporation shall not disclose confidential information to the Affiliate without the consent in writing of the consumer, retailer or generator, as the case may be, except where confidential information is required to be disclosed:
   - For billing or market operation purposes;
   - For law enforcement purposes;
   - For the purpose of complying with a legal requirement; or
   - For the processing of past due accounts of the consumer which have been passed to a debt collection agency.

3. Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual consumer, retailer, or generator's information cannot reasonable be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

Schedule B

"Services" means all the administrative, operational and maintenance activities of theCorporation which are services which shall be provided to the Corporation by the Affiliate including without limitation:

- all meter installation and reading operations
- all system control and data acquisition and control room operations
- all customer billing and collections operations
- all customer care services
- all health, security and risk management and safety programs
- all inventory and material management activities
- all accounting and bookkeeping services; and
- all activities associated with the overhead and underground distribution, transformation, subtransmission and system monitoring and operations.

Appendix B

CHAPLEAU PUBLIC UTILITIES CORPORATION

CONDITIONS OF SERVICE

Submitted to OEB

(Effective JULY 1, 2004)

Chapleau Public Utilities Corporation

PREFACE

CONDITIONS OF SERVICE

The Distribution System Code (DSC) requires that every Distributor produce its own "Conditions of Service" document. The purpose of this document is to provide a means for communicating the types and level of service available to the Customers within Chapleau Public Utilities Corporation's service area. The Distribution System Code requires that the Conditions of Service be readily available for review by the general public. In addition, the most recent version of the document must be provided to the Ontario Energy Board (OEB), which in turn will retain it on file for the purpose of facilitating dispute resolutions in the event that a dispute cannot be resolved between the Customer and its local distributor.

This document follows the form and general content of the Conditions of Service template appended to the DSC. The template was prepared to assist Distributors in developing their own "Conditions of Service" document based on current practice and the DSC. The template outlines the minimum requirements. However, as suggested by the DSC, Chapleau Public Utilities Corporation has expanded on the contents to encompass local characteristics and other specific requirements.

The General Section contains references to services and requirements that are common to all Customer classes. This section covers items such as Rates, Billing, Hours of Work, Emergency Response, Power Quality, Available Voltages and Metering.

The Customer Specific Section contains references to services and requirements specific to the respective Customer class. This section covers items such as Service Entrance Requirements, Delineation of Ownership, Special Contracts, etc.

Other sections include the *Glossary of Terms, Tables* and ***References.***

Subsequent changes will be incorporated with each submission to the OEB.

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Section 1 – INTRODUCTION

1 INTRODUCTION

1.1 Identification of Distributor and Service Area

Chapleau Public Utilities Corporation referred to herein as "Chapleau PUC", is a corporation incorporated under the laws of the Province of Ontario and a Distributor of electricity.

Chapleau PUC is licensed by the Ontario Energy Board ("OEB") to supply electricity to Customers as described in the Electricity Distribution License issued to Chapleau PUC on December 18, 2003 by the OEB ("Distribution License"). Additionally, there are requirements imposed on Chapleau PUC by the various codes referred to in the License and by the Electricity Act, 1998 and the Ontario Energy Board Act, 1998.

Chapleau PUC may only operate distribution facilities within its Licensed Territory as defined in its Distribution License. This service area is subject to change with the OEB's approval.

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

1.1.1 Distribution Overview

Chapleau PUC delivers electrical power through 4 kV & 25 kV primary distribution systems. All of the 25 kV circuit is overhead. All of the 4 kV circuit in the downtown area is overhead. It is the only voltage available in the downtown area.

Located in the northern part of the municipality boundaries, there is some single phase underground at 4 kV, mostly residential services.

1.2 Related Codes and Governing Laws

The supply of electricity or related services by Chapleau PUC to any Customer shall be subject to various laws, regulations, and codes, including the provisions of the latest editions of the following documents:

1. Electricity Act, 1998 } part of the Energy Competition
2. Ontario Energy Board Act, 1998 } Act, 1998
3. Distribution Licence
4. Affiliate Relationships Code
5. Transmission System Code
6. Distribution System Code

7. Retail Settlement Code
8. Standard Service Supply Code

In the event of a conflict between this document and the Distribution License or regulatory codes issued by the OEB, or the Energy Competition Act, 1998 (the "Act"), the provisions of the Act, the Distribution license and associated regulatory codes shall prevail in the order of priority indicated above. If there is a conflict between a Connection Agreement with a Customer and this Conditions of Service, this Conditions of Service shall govern.

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. Without limiting to the foregoing, the work shall be conducted in accordance with the latest edition of the Ontario Occupational Health and Safety Act (OHSA), the Regulations for Construction Projects and the harmonized Electric Utility Safety Association (EUSA) rulebook.

1.3 Interpretations

In these Conditions, unless the context otherwise requires:

- Headings, paragraph numbers and underlining are for convenience only and do not affect the interpretation of this Conditions;
- 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 this Conditions of Service and any amendments made from time to time form part of any Contract made between Chapleau PUC and any connected Customer, Retailer, or Generator, and this Conditions of Service supercedes all previous conditions of service, oral or written, of Chapleau PUC or any of its predecessor municipal electric utilities as of its effective date.

In the event of changes to this Conditions of Service, Chapleau PUC will issue a notice with the Customer's bill. Chapleau PUC may also issue a public notice in a local newspaper.

The Customer is responsible for contacting Chapleau PUC to ensure that the Customer has, or to obtain the current version of this Conditions of Service. Chapleau PUC may charge a reasonable fee for providing the Customer with a copy of this document.

1.5 Contact Information

Chapleau PUC can be contacted 24 hours a day at: 864-0111
864-1161
864-1027
864-2036
864-1437 or such other numbers as Chapleau PUC may advise through its invoices or otherwise. Normal working hours are Monday to Friday between 8:00 a.m. and 5:00 p.m. The corporate mailing address is

110 Lorne St. S., P. O. Box 670, Chapleau, Ontario P0M 1K0.

1.6 Customer Rights

Chapleau PUC shall only be liable to a Customer and a Customer shall only be liable to Chapleau PUC for any damages that arise directly out of the willful misconduct or negligence:

- of Chapleau PUC in providing distribution services to the Customer;
- of the Customer in being connected to Chapleau PUC's distribution system; or
- of Chapleau PUC or Customer in meeting their respective obligations under this Conditions, their licences and any other applicable law.

Notwithstanding the above, neither Chapleau PUC nor the Customer shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in contract, tort or otherwise.

1.7 Distributor Rights

1.7.1 Access to Customer Property

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

1.7.2 Safety of Equipment

The Customer will comply with all aspects of the Ontario Electrical Safety Code with Respect to insuring that equipment is properly identified and connected for metering and operation purposes and will take whatever steps necessary to correct any deficiencies, in particular cross wiring situations, in a timely fashion. If the Customer does not take such action within a reasonable time, Chapleau PUC may disconnect the supply of power to the Customer.

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 Chapleau PUC, interfere with the proper and safe operation of Chapleau PUC's facilities, or adversely affect compliance with any applicable legislation in the sole opinion of Chapleau PUC.

The Customer shall not use or interfere with the facilities of Chapleau PUC except in accordance with a written agreement with Chapleau PUC. The Customer must also grant Chapleau PUC the right to seal any point where a connection may be made on the line side of the metering equipment.

1.7.3 Operating Control

The Customer will provide a convenient and safe place, satisfactory to Chapleau PUC, for installing, maintaining and operating its equipment in, on, or about the Customer's premises. Chapleau PUC assumes no risk and will not be liable for damages resulting from the presence of its equipment on the Customer's premises or approaches thereto, or action, omission or occurrence beyond its control, or negligence of any Persons over whom Chapleau PUC has no control.

Unless an employee or an agent of Chapleau PUC, or other Person lawfully entitled to do so, no Person shall remove, replace, alter, repair, inspect or tamper with Chapleau PUC's equipment.

Customers will be required to pay the cost of repairs or replacement of Chapleau PUC's equipment that has been damaged or lost by the direct or indirect act or omission of the Customer or its agents.

The physical location on Customer's premises at which a distributor's responsibility for operational control of distribution equipment ends is defined by the DSC as the "operational demarcation point".

1.7.4 Repairs of Defective Customer Electrical Equipment

The Customer will be required to repair or replace any equipment owned by the Customer that may affect the integrity or reliability of Chapleau PUC's distribution system. If the Customer does not take such action within a reasonable time, Chapleau PUC may disconnect the supply of power to the Customer. Chapleau PUC's policies and procedures with respect to the disconnection process are further described in this Conditions.

1.7.5 Repairs of Customer's Physical Structures

Depending on the ownership demarcation point, construction and maintenance of all civil works on private property owned by the Customer, including such items as transformer vaults, transformer rooms, transformer pads, cable chambers, cable pull rooms and underground conduit, will be the responsibility of the Customer. All civil work on private property must be inspected and accepted by Chapleau PUC and the Electrical Safety Authority.

The Customer is responsible for the maintenance and keeping conditions satisfactory to Chapleau PUC of its structural and mechanical facilities located on private property.

1.8 Disputes

To resolve disputes, Chapleau PUC will follow the terms of Section 16 of the Electricity Distribution Licence.

Section 16 of the Electricity Distribution Licence states:

The Licensee shall:

a) establish proper administrative procedures for resolving complaints by Consumers and other market participants' complaints regarding services provided under the terms of this Licence;

b) publish information which will facilitate its Customers accessing its complaints resolution process;

c) refer unresolved complaints and subscribe to an independent third party complaints resolution agency which has been approved by the Board;

d) make a copy of the complaints resolution procedure available for inspection by members of the public at each of the Licencee's premises during normal business hours;

e) give or send free of charge a copy of the procedure to any person who reasonably requests it; and

f) keep a record of all complaints whether resolved or not including the name of the complainant, the nature of the complaint, the date resolved or referred and the result of the dispute resolution.

1.9 Miscellaneous Charges

All miscellaneous charges that might arise from disputes, late payment, reconnection charges etc. can be found in the Distribution Rate Order Application. It has not been supplied here because of the ongoing changes that will occur to it.

Section 2 – DISTRIBUTION ACTIVITIES (GENERAL)

2 DISTRIBUTION ACTIVITIES (GENERAL)

2.1 Connections – Process and Timing

Under the terms of the Distribution System Code, Chapleau PUC has the obligation to either connect or to make an offer to connect any Customers that lie in its service area.

The Customer or its representative shall consult with Chapleau PUC concerning the availability of supply, the supply voltage, service location, metering, and any other details. These requirements are separate from and in addition to those of the Electrical Safety Authority. Chapleau PUC will confirm, in writing, the characteristics of the electric supply.

The Customer or its authorized representative shall apply for new or upgraded electric services and temporary power services in writing. The Customer is required to provide Chapleau PUC with 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.

Chapleau PUC shall make every reasonable effort to respond promptly to a Customer's request for connection. Chapleau PUC shall respond to a Customer's written request for a Customer connection within 15 calendar days of receipt of the written request. Chapleau PUC will make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the Customer before the offer can be made.

Chapleau PUC shall make every reasonable effort to respond promptly to a generator's request for connection. In any event, Chapleau PUC shall provide an initial consultation with a generator that wishes to connect to the distribution system regarding the connection process within thirty (30) calendar days of receiving a written request for connection. A final offer to connect a generator to its distribution system shall be made within ninety (90) calendar days of receiving a written request for connection, unless other necessary information outside the distributor's control is required before the offer can be made.

Chapleau PUC shall make every reasonable effort to respond promptly to another distributor's request for connection. Chapleau PUC shall provide an initial consultation with another distributor regarding the connection process within thirty (30) days of receiving a written request for connection. A final offer to connect the distributor to Chapleau PUC's distribution system shall be made within ninety (90) days of receiving the written request for connection, unless other necessary information outside the distributor's control is required before the offer can be made.

Chapleau PUC, in its discretion, may require a Customer, generator or distributor to enter into a Connection Agreement with Chapleau PUC including terms and conditions in addition to those expressed in this Conditions (refer to the sample in the DSC Code – Appendix D).

If special equipment is required or equipment delivery problems occur then longer lead times may be necessary. Chapleau PUC will notify the Customer of any extended lead times.

In addition to any other requirements in this Conditions, the supply of electricity is conditional upon Chapleau PUC being permitted and able to provide such a supply, obtaining the necessary apparatus and material, and constructing works to provide the service. Should Chapleau PUC not be permitted or able to do so, it is under no responsibility to the Customer whatsoever and the Customer releases Chapleau PUC from any liability in respect thereto.

2.1.1. Building that Lies Along

Chapleau PUC is obligated to supply connection to any service lying along an existing distribution line. The term "lying along" is defined as being immediately adjacent to a distribution line capable of servicing the load without any further addition or expansion to the system. This expansion does not include plant required to connect the new load such as switches, insulators, cable, etc…

Any new service located along an existing distribution system shall be connected to the most convenient and closest point of connection as determined by Chapleau PUC. Alternate points of connection are possible but may incur a fee.

Fees apply if the amount of work is considered beyond that than the standard amount of work and material allowed for in the DSC and corporate policy. Fees will include all extra labour, trucking, material, burdens and taxes associated with this extra work.

2.1.2 Expansions / Offer To Connect

Under the terms of the DSC, Chapleau PUC has the Obligation to make an Offer to connect any service that is in its service territory that cannot be connected without an expansion or enhancement, or "lies along" its distribution system, but may be denied connection for the reasons described in subsection 2.1.3.

The expansion project will include all work up to the point whereby the new load is considered "along side". Additional connection fees apply from that point onwards see section 2.1.1. A project is considered an expansion if it involves any of the following:

1. The installation of a transformer.
2. The upgrade of an existing transformer.
3. The extension of pole line involving 3 or more poles.
4. The re-conductoring of a primary system in order to accommodate new load.
5. The replacement or upgrade of any other primary component (i.e. fuses, switches, poles, guys…) in order to accommodate the new load.

An offer to connect will be prepared detailing the extent and costs of the project as required by

the DSC. The process of connecting a new load, in which an expansion is required, shall follow the following steps:
The Customer is to contact Chapleau PUC (Engineering Department) and request a new service.

The request should be in writing and include the following information:

- Name of requestor,
- Date of request,
- Preferred voltage,
- Expected number of new services,
- Anticipated load of each service (both demand – kW, if applicable, and consumption – KWH),
- Estimated schedule for new load to come on line over the next 5 years.

Note that preferred voltage levels may not be available in every area. In addition, Chapleau PUC's policy limits the transformation it will supply to 1000kVA, after which the Customer must provide transportation (i.e. substation). If there are any questions, a representative of Chapleau PUC will consult the Customer.

Chapleau PUC will apply the DCF method described in the DSC (Appendix B) to calculate any expected capital contribution that is required.

An Offer to Connect will be issued to the Customer and will include the details of the original request and the estimated quantities that were used in the calculation of any required capital contribution.

Upon acceptance of an Offer to Connect, Chapleau PUC will begin engineering and construction of the expansion required to service the new load. Final connection will only be completed when:

- The Customer installed electrical system passes all relevant inspections (i.e. ESA),
- The Customer signs the Connection Agreement,
- The Customer pays any outstanding capital contributions and fees (as applicable).

Upon receipt of final passed inspection from ESA, Chapleau PUC will connect the new service as quickly as possible.

In the case of a subdivision development ESA inspection may not be required but Chapleau PUC may still prove the system via Hypot test or other suitable test as determined by Chapleau PUC.

Subdivision Developments are considered an expansion project and the work is limited up to the service drop at the property line of each individual lot. Connection fees will be calculated on an individual basis as each new house is connected.

2.1.3 Connection Denial

The Distribution System Code provides for the ability of a Distributor to deny connections. A Distributor is not obligated to connect a building within its service area if the connection would result in any of the following:

- Contravention of existing laws of Canada and the Province of Ontario

- Violations of conditions in Chapleau PUC's 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 affect on the reliability or safety of the distribution system

- Public safety reasons or 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 distributor's distribution system
- A materially adverse effect on the quality of distribution services received by an existing connection
- Discriminatory access to distribution services
- If the person requesting the connection owes Chapleau PUC money for distribution services
- Potential increases in monetary amounts that already are in arrears with the distributor
- If an electrical connection to Chapleau PUC's distribution system does not meet Chapleau PUC's design requirements
- Any other conditions documented in Chapleau PUC's Conditions of Service document.

If Chapleau PUC refuses to connect a building in its service area that lies along one of its distribution lines, Chapleau PUC shall inform the person requesting the connection of the reasons for the denial, and where Chapleau PUC is able to provide a remedy, make an offer to connect. If Chapleau PUC is not capable of resolving the issue, it is the responsibility of the Customer to do so before a connection can be made.

2.1.4 Inspections Before Connections

All Customer electrical installations shall be inspected and approved by the Electrical Safety Authority and must also meet Chapleau PUC's requirements. Chapleau PUC requires notification from the Electrical Safety Authority of this approval prior to the energization of a Customer's supply of electricity.
Services that have been disconnected for a period of six months or longer must also be re-inspected and approved by the Electrical Safety Authority, prior to reconnection.

Temporary services, typically used for construction purposes and for a period of twelve months or less, must be approved by the Electrical Safety Authority and must be re-inspected should the period of use exceed twelve months.

Customer owned substations must be inspected by both the Electrical Safety Authority and Chapleau PUC.

Transformer rooms shall be inspected and approved by Chapleau PUC prior to the installation of Chapleau PUC's equipment.

Duct banks shall be inspected and approved by Chapleau PUC prior to the pouring of concrete and again before backfilling. The completed ducts must be rodded by the site contractor in the presence of a Chapleau PUC inspector and shall be clear of all extraneous material. A mandrel, approved by Chapleau PUC for a nominal diameter of duct, will be passed through each duct. In the event of ducts blocked by ice, the owner's representative will be responsible for clearing the ducts prior to the cable installation. Connection to existing concrete duct banks or

cable chamber shall be done only by a contractor approved by Chapleau PUC. All work done on existing Chapleau PUC's plant must be authorized by Chapleau PUC and carried out in accordance with all applicable safety acts and regulations.

Provision for metering shall be inspected and approved by Chapleau PUC prior to energization.

2.1.5 Relocation of Plant

When requested to relocate distribution plant, Chapleau PUC will exercise its rights and discharge its obligations in accordance with existing acts, by-laws and regulations including the *Public Service Works on Highways Act,* formal agreements, easements and law. In the absence of existing agreements, Chapleau PUC is not obligated to relocate the plant. However, Chapleau PUC shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner will include a response to the requesting party that explains the feasibility or unfeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles.

2.1.6 Easements

To maintain the reliability, integrity and efficiency of the distribution system, Chapleau PUC has the right to have supply facilities on private property and to have easements registered against title to the property. Easements are required where facilities serve property other than property where the facilities are located and/or where Chapleau PUC deems it necessary.

The Customer will prepare at its own cost any required reference plan to the satisfaction of Chapleau PUC. Easement documents are prepared by the Chapleau PUC Legal Services department. Four copies of the deposited reference plan must be supplied to Chapleau PUC prior to the preparation of the easement documents. Details will be provided upon application for service.

2.1.7 Contracts

2.1.7.1 Contract for New or Modified Electricity Service

Chapleau PUC shall only connect a Building for a new or modified supply of electricity upon receipt by Chapleau PUC of a completed and signed contract for service in a form acceptable to Chapleau PUC, payment to Chapleau PUC of any applicable connection charge, and an inspection and approval by the Electrical Safety Authority of the electrical equipment for the new service.

2.1.7.2 Implied Contract

In all cases, notwithstanding the absence of a written contract, Chapleau PUC has an implied contract with any Customer that is connected to Chapleau PUC's distribution system and receives distribution services from Chapleau PUC. The terms of the implied contract are embedded in Chapleau PUC's Conditions of Service, the Rate Handbook, Chapleau PUC's rate schedules, Chapleau PUC's licence and the Distribution System Code, as amended from time to time.

Any Person or Persons who take or use electricity from Chapleau PUC shall be liable for payment for such electricity. Any implied contract for the supply of electricity by Chapleau

PUC shall be binding upon the heirs, administrators, executors, successors or assigns of the Person or Persons who took and/or used electricity supplied by Chapleau PUC.

2.1.7.3 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

2.1.7.4.1 Payment by Building Owner

The owner of a Building is responsible for paying for the supply of electricity by Chapleau PUC to the owner's Building except for any supply of electricity to the Building by Chapleau PUC in accordance with a written request for electricity by an occupant(s) of the Building.

A Building owner wishing to terminate the supply of electricity to its Building must notify Chapleau PUC in writing. Until Chapleau PUC receives such written notice from the Building owner, the Building owner or the occupant(s), as applicable, shall be responsible for payment to Chapleau PUC for the supply of electricity to such Building. Chapleau PUC may refuse to terminate the supply of electricity to an owner's Building when there are occupant(s) in the Building (i.e. during certain periods of the winter).

2.1.7.4.2 Opening and Closing of Accounts

A Customer who wishes to open an account for the supply of electricity by Chapleau PUC shall contact Chapleau PUC's office by phone, by written request (including requests submitted by facsimile), or other means acceptable to Chapleau PUC.

A Customer who wishes to close an account with Chapleau PUC (i.e. because the Customer moves to another location, or the Customer wishes to purchase electricity from another supplier, or otherwise) must notify Chapleau PUC in writing. Until Chapleau PUC receives such written notice from the Customer or its authorized retailer, the Customer shall be responsible for payment to Chapleau PUC for the supply of electricity to the Customer.

2.2 Disconnection

Chapleau PUC reserves the right to disconnect the supply of electrical energy for causes not limited to:

- Contravention of the laws of Canada or the Province of Ontario.
- Adverse effect on the reliability and safety of the distribution system.
- Imposition of an unsafe worker situation beyond normal risks inherent in the

operation of the distribution system.
- A material decrease in the efficiency of the distributor's distribution system.
- A materially adverse effect on the quality of distribution services received by an existing connection.
- Discriminatory access to distribution services.

- Inability of Chapleau PUC to perform planned inspections and maintenance.
- Failure of the Consumer or Customer to comply with a directive of Chapleau PUC that Chapleau PUC makes for purposes of meeting its licence obligations.
- Overdue amounts payable to Chapleau PUC for the distribution or retail of electricity.
- Electrical disturbance propagation caused by Customer equipment that are not corrected in a timely fashion.
- Any other conditions identified in this Conditions of Service document.

Chapleau PUC may disconnect the supply of electricity to a Customer without notice in accordance with a court order, or for emergency, safety or system reliability reasons.

2.2.1 Disconnection & Reconnection – Process and Charges

Immediately following the due date, steps will be taken to collect the full amount of the bill. If the bill is still unpaid fourteen calendar days after the due date, the service may be disconnected and not restored until satisfactory payment arrangements have been made, including costs of reconnection. Such discontinuance of service does not relieve the Customer of the liability for arrears or minimum bills for the balance for the term of contract, nor shall Chapleau PUC be liable for any damage to the Customer's premises resulting from such discontinuance of service. Prior to shutting off the hydro, a service representative will make reasonable efforts to establish direct contact with the Customer.

Along with the disconnection notice, the customer will be given a hand out from the Ministry of Community and Correctional Services on Fire Safety while electricity has been disconnected.

Upon discovery that a hazardous condition or disturbance propagation (feedback) exists, Chapleau PUC will notify the Customer to rectify the condition at once. In case the Customer fails to make satisfactory arrangements to remedy the condition within seven calendar days after a disconnect notice has been given to the Customer, the service may be disconnected and not restored until satisfactory arrangements to remedy the condition have been made. Chapleau PUC shall not be liable for nay damage to the Customer's premises resulting from such discontinuance of service. Disconnect notices will be in writing and if given by mail shall be deemed to be received on the third business day after mailing.

Upon receipt of a Disconnection request by the Customer, Chapleau PUC will disconnect and/or remove Chapleau PUC's connection assets.

2.2.2 Unauthorized Energy Use

Chapleau PUC reserves the right to disconnect the supply of electrical energy to a Customer for causes not limited to energy diversion, fraud or abuse on the part of the Customer. Such service may not be reconnected until the Customer rectifies the condition and provides full payment to Chapleau PUC including all costs incurred by Chapleau PUC arising from unauthorized energy use, including inspections, repair costs, and the cost of disconnection and reconnection.

2.3 Conveyance of Electricity

2.3.1 Limitations on the Guaranty of Supply

Chapleau PUC will endeavor 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 higher degree of security than that of normal supply are responsible to provide their own back-up or standby facilities. Customers may require special protective equipment at their premises to minimize the effect of momentary power interruptions.

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 Distributor's supply.

During an emergency, Chapleau PUC may interrupt supply to a Consumer in response to a shortage of supply, or to effect repairs on the distribution system, or while repairs are being made to Consumer-owned equipment.

Chapleau PUC shall have rights to access to a property in accordance with section 40 of the *Electricity Act, 1998* and any successor acts thereto.

To assist with distribution system outages or emergency response, Chapleau PUC may require a Customer to provide Chapleau PUC with emergency access to Customer-owned distribution equipment that normally is operated by Chapleau PUC or Chapleau PUC-owned equipment on Customer's property.

2.3.2 Power Quality

2.3.2.1 Power Quality Testing

In response to a Consumer power quality concern, where the utilization of electric power adversely affects the performance of electrical equipment, Chapleau PUC will perform investigative analysis to attempt to identify the underlying cause.

Upon determination of the cause resulting in the power quality concern, where it is deemed a system delivery issue and where industry standards are not met, Chapleau PUC will recommend and/or take appropriate mitigation measures. Chapleau PUC will take appropriate actions to control power disturbances found to be detrimental to the Consumers. If Chapleau PUC is unable to correct the problem without adversely affecting other Chapleau PUC Consumers, then it is not obligated to make the corrections. If the problem lies on the Consumer side of the system, Chapleau PUC may seek reimbursement from the Consumer for the costs incurred in its investigation.

2.3.2.2 Obligation to Help in the Investigation

If Chapleau PUC determines the Consumer's equipment may be the source causing unacceptable harmonics, voltage flicker or voltage level on Chapleau PUC's distribution system, the Consumer is obligated to help Chapleau PUC by providing required equipment information, relevant data and necessary access for monitoring the equipment.

2.3.2.3 Timely Correction of Deficiencies

If an undesirable system disturbance is being caused by Consumer's equipment, the Consumer will be required to cease operation of the equipment until satisfactory remedial action has been taken by the Consumer at the Consumer's cost. If the Consumer does not take such action within a reasonable time, Chapleau PUC may disconnect the supply of power to the Consumer.

2.3.2.4 Notification for Interruptions

Although it is Chapleau PUC's policy to minimize inconvenience to Customers, it is necessary to occasionally interrupt a Customer's supply to allow work on the electrical system. Chapleau PUC will endeavor to provide the Customers with reasonable notice of planned power interruptions. Notice may not be given where work is of an emergency nature involving the possibility of injury to persons or damage to property or equipment.

However, during an emergency, Chapleau PUC may interrupt supply to a Consumer in response to a shortage of supply or to effect repairs on Chapleau PUC's distribution system or while repairs are being made ton Consumer-owned equipment.

2.3.2.5 Notification to Consumers on Life Support

Consumers who require an uninterrupted source of power for life support equipment must provide their own equipment for these purposes. Consumers with life support system are encouraged to inform Chapleau PUC of their medical needs and their available backup power. These Customers are responsible for ensuring that the information they provide Chapleau PUC is accurate and up-to-date.

With planned interruptions, the same procedure as prescribed in section 2.3.2.4 will be observed. For those unplanned power interruptions that extend beyond two hours and the time expected to restore power is longer than what was indicated by Consumers (registered on life support) as their available backup power, Chapleau PUC will endeavor to contact these Consumers but will not be liable in any manner to the Consumers for failure to do so.

2.3.2.6 Emergency Interruptions for Safety

Chapleau PUC will endeavor to notify Customers prior to interrupting the supply to any 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 Chapleau PUC or the public, service may be interrupted without notice.

2.3.2.7 Emergency Service (Trouble Calls)

Chapleau PUC will exercise reasonable diligence and care to deliver a continuous supply of electrical energy to the Customer. However, Chapleau PUC cannot guarantee a supply that is free from interruption.

When power is interrupted, the Customer should first ensure that failure is not due to blowing of fuses within the installation. If there is a partial power failure, the Customer should obtain the services of an electrical contractor to carry out necessary repairs. If, on examination, it appears that Chapleau PUC's main source of supply has failed, the Customer should report these conditions by calling one of these numbers: 864-0111, 864-1161, 864-1027, 864-2036 or 864-1437.

2.3.3 Electrical Disturbances

Chapleau PUC shall not be held liable for the failure to maintain supply voltages within standard levels due to Force Majeure as defined in Section 2.3.5 of this Conditions.

Voltage fluctuations and other disturbances can cause flickering of lights and other serious difficulties for Customers connected to Chapleau PUC's distribution system. Customers must ensure that their equipment does not cause disturbances such as harmonics and spikes that might interfere with the operation of adjacent Customer equipment. Equipment that may cause disturbances include large motors, welders and variable speed drives, etc. In planning the installation of such equipment, the Customer must consult with Chapleau PUC.

Customers who may require an uninterrupted source of power supply or a supply completely free from fluctuation and disturbance must provide their own power conditioning equipment for these purposes.

2.3.4 Standard Voltage Offerings

2.3.4.1 Primary Voltage

The primary voltage to be used will be determined by Chapleau PUC for both Chapleau PUC-owned and Customer-owned transformation. Depending on what voltage of the plant that "lies along", the preferred primary voltage will be at 4 kV/2.4 kV or 25 kV/14.4 kV, grounded wye, three phase, four-wire system. However, in the downtown core of the Town, the primary voltage will be 4 kV/2.4 kV grounded wye, three phase, four wire only.

2.3.4.2 Supply Voltage

Depending on what voltage of plant "lies along" Chapleau PUC's distribution system, the preferred secondary voltage will be at 120/240 V, single phase, 120/208 V, 600 V, three phase or 600/347 V, three phase.

The limit of supply capacity for any Customer is governed by the Supply Voltage. General Guidelines for supply from overhead street circuits are as follows:

(i) at 120/240 V, single phase up to 75 kVA demand load, or

(ii) at 600 V, three phase or 600/347 V, three phase, four wire up to 80 kVA demand load, or

(iii) at both 120/240 V, single phase and 600 V, three phase, or 600/347 V, three phase, four wire up to 100 kVA sum total demand load, or

(iv) at 208 V, three phase or 208/120 V, three phase, four wire up to 100 kVA demand load,

OR

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

2.3.5 Voltage Guidelines

Chapleau PUC maintains service voltage at the Customer's service entrance with the guidelines. See chart below.

NOMINAL SYSTEM VOLTAGE	EXTREME	OPERATING FAVOURABLE (NORMAL) OPERATING CONDITIONS		CONDITIONS
Single Phase				
120/24	106/212	110/220	125/250	127/254
240	212	220	250	254
600	530	550	625	635
Three-Phase 4 Conductor				
120/208 Y	110/190	112/194	125/216	127/220
347/600 Y	306/530	318/550	360/625	367/635
Three-Phase 3 Conductor				
240	212	220	250	254
600	530	550	625	635

Where voltages lie outside the indicated limits for Normal Operating Conditions but within the indicated limits for Extreme Operating Conditions, improvement or corrective action should 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 should 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.

Chapleau PUC shall practice reasonable diligence in maintaining voltage levels, but is not responsible for variations in voltage from external forces such as operating contingencies, exceptionally high loads and low voltage supply from the transmitter or host Distributor. Chapleau PUC shall not be liable for any delay or failure in the performance of any of its obligations under this conditions of Supply due to any events or causes beyond the reasonable control of Chapleau PUC, including, without limitation, severe weather, flood, fire, lightning, other forces of nature, acts of animals, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes ("Force Majeure").

2.3.6 Back-up Generators

Customers with portable or permanently connected generation capability used for emergency back-up shall comply with all applicable criteria of the Ontario Electrical Safety Code. In particular, the Customer shall ensure that Customer's emergency generation does not parallel with Chapleau PUC's system without a proper interface protection and does not adversely affect Chapleau PUC's distribution system.

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

2.3.7 Metering

Chapleau PUC will supply, install, own, and maintain all meters, ancillary devices, and secondary wiring required for revenue metering.

Additional metering requirements are listed in the Distribution System Code. Metered Market Participants in the Independent Electricity Market Operator ("IMO") administered wholesale market must meet or exceed all IMO metering requirements.

2.3.7.1 General

Chapleau PUC will typically install metering equipment at the Customer supply voltage. The Customer must provide a convenient and safe location satisfactory to Chapleau PUC, for the installation of meters, wires and ancillary equipment. Meters for new or upgraded residential services will be mounted outdoors on a meter socket approved by Chapleau PUC & E.S.A.

No person, except those authorized by Chapleau PUC, may remove, connect, or otherwise interfere with meters, wires, or ancillary equipment.

The Customer will be responsible for the 78care and safekeeping of Chapleau PUC meters,

wires and ancillary equipment on the Customer's premises. If any Chapleau PUC equipment installed on Customer premises is damaged, destroyed, or lost other than by ordinary wear and tear, tempest or lightning, the Customer will be liable to pay to Chapleau PUC the value of such equipment, or at the option of Chapleau PUC, the cost of repairing the same.

The location allocated by the owner for Chapleau PUC metering shall provide direct access for Chapleau PUC staff and shall be subject to satisfactory environmental conditions, some of which are:

- Maintain a safe and adequate working space in front of equipment, not less than 1.2 metres (48") and a minimum ceiling height of 2.1 metres (84").
- Maintain an unobstructed working space in front of equipment, free from, or protected against, the adverse effects of moving machinery, vibration, dust, moisture or fumes.

Where Chapleau PUC deems self-contained meters to be in a hazardous location, the Customer shall provide a meter cabinet or protective housing.

Any compartments, cabinets, boxes, sockets, or other work-space provided for the installation of Chapleau PUC's metering equipment shall be for the exclusive use of Chapleau PUC. No equipment, other than that provided and installed by Chapleau PUC, may be installed in any part of the Chapleau PUC metering work-space.

2.3.7.1.1 Main Switch and Meter Mounting Devices

The Customer's main switch immediately preceding the meter shall be installed so that the top of the switch is 1.83 m or less from the finished floor and shall permit the sealing and padlocking of:

(a) the handle in the "open" position; and
(b) the cover or door in the closed position.

Meter mounting devices for use on Commercial/Industrial accounts shall be installed on the load side of the Customer's main switch and be located indoors.

The Customer is required to supply and install a Chapleau PUC approved meter socket for the use of Chapleau PUC's self-contained socket meters for the main switch ratings and supply voltages listed in Table 3 appended to this Conditions.

The Customer is required to supply and install a meter cabinet to contain Chapleau PUC's metering equipment for the main switch ratings and supply voltages listed in Table 2 appended to this Conditions.

Meter centers installed for individual metering applications must meet the requirements specified in Table 4 appended to this Conditions.

The Customer shall permanently and legibly identify each metered service with respect to its specific address, including unit or apartment number. The identification shall be applied to all service switches, circuit breakers, meter cabinets, and meter mounting devices.

2.3.7.1.2 Service Mains Limitations

The metering provision and arrangement for service mains in excess of either 600 A or 600 V shall be submitted to Chapleau PUC for approval before building construction begins. Additional standards and requirements for services metered above 600 V can be made available upon request.

2.3.7.1.3 Special Enclosures

Specially constructed meter entrance enclosures will be permitted for outdoor use upon Chapleau PUC's approval of a written application for use.

2.3.7.1.4 Meter Loops

The Customer shall provide meter loops having a length of 610-mm in addition to the length between line and load entry points. Line and load entry points shall be approved by Chapleau PUC prior to installation. Where more than two conductors per phase are used, the connectors shall be provided by the Customer. (see Table 3 for required cabinets)

Mineral insulated, solid or hard drawn wire conductors are not acceptable for meter loops.

Any variation from the above must first be checked and approved by Chapleau PUC prior to installation.

2.3.7.2 Current Transformer Boxes

Where instrument transformers are incorporated in low voltage switchgear, the size of the chamber and number of instrument transformers shall be as shown in Table 2 appended to this Conditions. Installation must meet all of the Ontario Electrical Safety Code.

2.3.7.3 Interval Metering

Interval meters will be installed for any Customer wishing to participate in the spot market pass-through pricing. Prior to the installation of an interval meter, the Customer must provide a phone line jack in the meter cabinet. The Customer will be responsible for the installation and ongoing monthly costs of operating the phone line. A charge approved by the OEB for processing interval meters will be charged to Customers.

Other Customers that request interval metering shall compensate Chapleau PUC 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 reverification 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.

2.3.7.4 Meter Reading

The Customer must provide or arrange free, safe and unobstructed access during regular business hours to any authorized representative of Chapleau PUC for the purpose of meter reading, meter changing, or meter inspection. Where premises are closed during Chapleau PUC's normal business hours, the Customer must, on reasonable notice, arrange such access at a mutually convenient time.

2.3.7.5 Final Meter Reading

When a service is no longer required, the Customer shall provide sufficient notice of the date the service is to be discontinued so that Chapleau PUC can obtain a final meter reading as close as possible to the final reading date. The Customer shall provide access to Chapleau PUC 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.

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. Chapleau PUC's 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, Chapleau PUC 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 Chapleau PUC, due regard being given to any change in the characteristics of the installation and/or the demand. If Measurement Canada, Industry Canada determines that the Customer was overcharged, Chapleau PUC will reimburse the Customer for the amount incorrectly billed.

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. Chapleau PUC will correct the bills for that period in accordance with the regulations under the Electricity and Gas Inspection Act.

2.3.7.7 Meter Dispute Testing

Metering inaccuracy is an extremely rare occurrence. Most billing inquiries can be resolved between the Customer and Chapleau PUC without resorting to the meter dispute test.

Either Chapleau PUC or the Customer may request the service of Measurement Canada to resolve a dispute. If the Customer initiates the dispute, Chapleau PUC will charge the Customer a meter dispute fee if the meter is found to be accurate and Measurement Canada rules in favor of the utility.

2.4 Tariffs and Charges

2.4.1 Service Connection

Charges for distribution services are made as set out in the Schedule of Rates available from Chapleau PUC. Notice of Rate revisions shall be published in major local newspapers.

2.4.1.1 Customers Switching to

Retailer

There are no physical service connection differences between Standard Service Supply (SSS) Customers and third party retailers' Customers. Both Customer energy supplies are delivered through the local Distributor with the same distribution requirements. Therefore, all service connections requirements applicable to the SSS Customers are applicable to third party retailers' Customers.

2.4.1.2 Supply Deposits & Agreements

Where an owner proposes the development of premises that require Chapleau PUC to place orders for equipment for a specific project and before actual construction begins, the owner is required to sign the necessary Supply Agreement and furnish a suitable deposit before such equipment is ordered by Chapleau PUC.
An irrevocable (standby) letter of credit or a letter of guarantee from a chartered bank, trust company or credit union is acceptable in lieu of a cash deposit.

2.4.2 Energy Supply

2.4.2.1 Standard Service Supply (SSS)

All existing Chapleau PUC Customers are Standard Service Supply (SSS) Customers until Chapleau PUC is informed of their switch to a competitive electricity supplier. The Service Transfer Request (STR) must be made by the Customer or the Customer's authorized retailer.

2.4.2.2 Retailer Supply

Customers transferring from Standard Service Supply (SSS) to a retailer shall comply with the Service Transfer Request (STR) requirements as outlined in sections 10.5 through 10.5.6 of the Retail Settlement Code.

All requests shall be submitted as electronic file and transmitted through EBT Express. Service Transfer Request (STR) shall contain information as set out in section 10.3 of the Retail Settlement Code.

If the information is incomplete, Chapleau PUC shall notify the retailer or Customer about the specific deficiencies and await a reply before proceeding to process the transfer.

2.4.3 Deposits

Chapleau Public Utilities Corporation requires the following deposit and prudential requirements before providing a Customer with Distribution Services, supply through Standard Service Supply or through Distributor Consolidated Billing.

1) Except for Customers who meet the deposit waiver conditions described below, all Customers are required to either pay a security deposit or provide a guarantee to Chapleau Public Utilities Corporation for payment of all monies owing.

2) Security deposits for Residential Customers shall be in the form of cash or cheque. Security deposits for Non-Residential Customers shall be in the form of cash, cheque or an irrevocable (standby) letter of credit, a bond or a letter of guarantee from a reputable third party (i.e. parent company or customer of the Corporation whose

account is in good standing). Note: The following statement must be included on the irrevocable letter of credit: "It is a condition of this Letter of Credit that it shall be deemed to be automatically extended without amendment from year to year from the

present or any future expiration date hereof, unless at least 30 days prior to the present or any future expiration date, we notify you in writing by registered mail that we elect not to consider this Letter of Credit to be renewable for any additional period."

3) The amount of the security deposit will be calculated as follows:

- Residential Customer Billed Monthly – the average monthly bill for the residence in question (over the most recent 12 consecutive months within the past two years) multiplied by 2.5.
- Residential Customer Billed Bi-Monthly – the average bill for the residence in question (over the most recent 12 consecutive months within the past two years) multiplied by 1.75.
- Non Residential Customer – in any rate class other than a <50 kW demand rate who has a credit rating from a recognized credit rating agency shall have the maximum amount of a security deposit reduced according to the following table:

Credit Rating Allowable Reduction in Security Deposit
(Using Standard and Poor's Rating Terminology)

AAA – and above or equivalent	100%
AA-, AA, AA+ or equivalent	95%
A-, From A, A+ to below AA or equivalent	85%
BBB-, From BBB, BBB+ to below A or equivalent	75%
Below BBB- or equivalent	0%

4) A minimum of 25% of the required deposit must be paid before the service is transferred into the new customers name. The remaining 75% will be billed on the first three regular utility bills and must be paid by the due date of said bills or an immediate disconnection will be ordered.

5) Security Deposits will be reviewed annually. Deposits will be increased at that time if a recalculation warrants same. Deposits will be returned to the Customer if it is proven that the Customer is now in a position to be exempt from paying a Deposit. Returned amounts will usually be credited to the Customer's account.

6) Security deposits or guarantees may be waived if the following conditions are met:

a) Residential customers provide evidence of a good payment record during the previous one (1) year with another distributor or gas distributor in Canada.
Non-Residential customers in a <50kW demand rate class provide a good record of five (5) years and customers in any other rate class provide a good record of seven (7) years.

b) The customer provides a satisfactory credit check made at the customer's expense.

7) Security deposits shall not constitute payment of an outstanding account, in whole or in part, and shall only be applied to amounts owing on an Chapleau Public Utilities Corporation account when the account is closed at which time any excess deposit funds will be refunded to the Customer. However, the Utility reserves the right to transfer a deposit credit to the customer's new outstanding deposit account. The Security deposit will be returned within six weeks of the closure of the account.

8) The interest rate on cash deposits shall be at the Prime Business Rate less 2% and will be applied to the deposit, on receipt of the total deposit, on a yearly basis or on return or application of the security deposit or closure of the account, whichever comes first. Non-cash security (i.e. letter of credit) will be applied after the final-bill-due-date, if full payment is not received from the Customer.

2.4.4 Billing

Chapleau PUC may, at its option, render bills to its Customers on either a monthly or bi-monthly basis. Bills for the use of electrical energy may be based on either a metered rate or a flat rate, as determined by Chapleau PUC.

Where billing errors have resulted in over billing, the Customer will be credited with the amount erroneously paid for a period not exceeding six years.

Where billing errors have resulted in under billing, the Customer shall be charged with the amount erroneously not billed for a period not exceeding two years, in the case of an individual residential customer who was not responsible for the error and six years, in other cases.

2.4.5 Payments and Overdue Account Interest Charges

Bills are rendered for energy services provided to the Customer. Bills are payable in full by the due date; otherwise, overdue interest charge will apply. Where a partial payment has been made by the Customer on or before the due date, the interest charge will apply only to the amount of the bill outstanding at the due date. In the event of partial payment by a Customer, payments shall be allocated by the portions of the bill covering competitive and non-competitive electricity costs based on the ratios of the amount billed for competitive and non-competitive costs. Outstanding bills are subject to the collection process and may ultimately lead to the service being discontinued. Service will be restored once satisfactory payment has been made. Discontinuance of service does not relieve the Customer of the liability for arrears.

Chapleau PUC shall not be liable for any damage on the Customer's premises resulting from such discontinuance of service. A reconnection charge will 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 ($15.00).

There will be no late payment charges applied to the account within a 16-calendar day of the date of our mailing. Late payment charges of 1.5% per month will be applied after the due date.

Additional charges may be made for costs associated with the continued non-payment for amounts due, including costs of additional notices and of shutting off and reconnecting the utility.
NOTE: The late payment charge applied to your account after the due date is not an extension of credit.

Disconnect notices will be issued following due date, with disconnect date 10 days after due date. Prior to shutting off the utility, a service representative will make reasonable efforts to establish direct contact with the Customer. Chapleau PUC has adopted zero tolerance policy as follows:

Hydro bills will be issued on the 1st day of every month.

The due date will be the 16th day of every month.

A penalty of 1.5% will be applied immediately after the due date.

Following application of 1.5% penalty, disconnect notices will be mailed, disconnect date being 10 days after.

If the 16th day of the month should fall on a weekend, the following Monday will be considered the due date.

2.5 Customer Information

A third party who is not a retailer may request historical usage information with the written authorization of the Customer.

A retailer and Customer must follow the rules set out in Chapter 11 of the Retail Settlement Code. This will also be the rules Chapleau PUC will follow at all times.

Section 3 – CUSTOMER CLASS SPECIFIC

3 CUSTOMER CLASS SPECIFIC

3.1 Residential

Refer to Table 1 for Point of Demarcation, Standard Allowance and Connection Fees for Residential Services.

3.1.1 Overhead Services

3.1.1.1 Minimum Requirements

In addition to the requirements of the Ontario Electrical Safety Code (latest edition), the following conditions shall apply:

(i) This point of attachment device must be located:

(a) Not less than 4.5 metres (15 feet) nor greater than 5.5 metres (18 feet) above grade (to facilitate proper ladder handling techniques). Building must have a minimum offset from property line of 1.2 metres (4 feet).

(b) Between 150 millimeters and 300 millimeters (6 – 12 inches) below the service head.

(ii) Clearance must be provided between utility conductors and finished grade of at least 6 metres (19 feet) over traveled portions of the road allowance and 4.5 metres (15 feet) over all other areas.

A minimum horizontal clearance of 1.0 metres (39 inches) must be provided from utility conductors and any second storey windows.

(iii) A large, 4 jaw meter socket of an approved manufacturer shall be provided. Certain areas will require a 5-jaw socket as determined by Chapleau PUC. The Customer should contact Chapleau PUC to confirm details.

(iv) Clear unobstructed access must be maintained to and in front of the meter location.

(v) The approved meter base shall be mounted directly below the service mast such that the midpoint of the meter is 1.73 m (± 100 mm) above finished grade within 914 mm of the face of the building (in front of any existing or proposed fence), unless otherwise approved by Chapleau PUC.

3.1.2 Underground Services for Individual Residences

Customers requesting an underground service in an overhead area will be required to pay 100% connection costs for the 86underground service.

The owner shall pay for any necessary road crossings.

Where there are other services to be installed (e.g. gas, telephone and cable) these shall be coordinated to avoid conflict with Chapleau PUC's underground cables. Chapleau PUC's installation will not normally commence until all other servicing and grading have been completed.

It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including Hydro) before digging.

The owner shall provide unimpeded access for Chapleau PUC to install the service.

The owner shall ensure that any intended tree planting has appropriate clearance from underground electrical plant.

3.2 General Service

(a) The Customer shall supply the following to Chapleau PUC well in advance of installation commencement:

- Required in-service date
- Proposed Service Entrance equipment's Rated Capacity (Amperes) and Voltage rating and metering requirements
- Proposed Total Load details in kVA and/or kW (Winter and Summer)
- Locations of other services, gas, telephone, water and cable TV
- Details respecting heating equipment, air-conditioners, motor starting current limitation and any appliances which demand a high consumption of electrical energy.
- Survey plan and site plan indicating the proposed location of the service entrance equipment with respect to public rights-of-way and lot lines

(b) The Customer shall construct or install all civil infrastructure (including but not limited to poles, UG conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property, that is deemed required by Chapleau PUC as part of its Connection Assets. All civil infrastructure are to be in accordance with Electrical Safety Authorization Standards or Hydro One Construction Standards specifications and this Conditions of Service and are subject to Chapleau PUC's inspection and acceptance.

(c) Chapleau PUC is responsible for the maintenance and repairs of its Connection Assets **but not** the Transformer Room(s) or any other civil structure that forms part or is part of the Customer's building.

(d) When effecting changes the Customer shall maintain sufficient clearances between electrical equipment and Buildings and other permanent structures to meet the requirements of the Ontario Electrical Safety Code and the Occupational Health & Safety Act and Regulations.

(e) It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies (including Hydro) before digging. Refer to Table 1 for Point of Demarcation, Standard Allowance and Connection Fees for General Service.

3.2.1 Electrical Requirements (as applicable)

For low voltage supply, the Customer's service entrance equipment shall be suitable to accept conductors installed by Chapleau PUC. The Customer's cables shall be brought to a point determined by Chapleau PUC for connection to Chapleau PUC's supply.

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.

Access doors, panels, slabs and vents shall be kept free from obstructing objects. The Customer will provide unimpeded and safe access to Chapleau PUC at all times for the purpose of installing, removing, maintaining, operating or changing transformers and associated equipment.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code and shall be located indoors.

Outside doors providing access to electrical rooms must have at least 150-mm clearance between final grade and the bottom of the door. Electrical rooms 'on' or 'below' grade must have a drain including a "P" trap complete with a non-mechanical priming device and a backwater valve connected to the sanitary sewer. The electrical room floor must slope 6-mm/300 mm or 2% towards the drain.

The electrical room shall have a minimum ceiling height of 2.2 m clear, be provided with adequate lighting at the working level, in accordance with Illuminating Engineering Society (I.E.S.) standards, and a 120 V convenience outlet. The lights and convenience outlet noted above and any required vault circuit shall be supplied from a panel located and clearly identified in the electrical room.

3.2.2 Underground Service Requirements

The Customer shall construct or install all civil infrastructure (including but not limited to poles, UG conduits, cable chambers, cable pull rooms, transformer room/vault/pad) on private property, that is deemed required by Chapleau PUC as part of its Connection Assets. All civil infrastructure are to be in accordance with Electrical Safety Authorization or Hydro One Construction Standards, practices, specifications and this Conditions of Service and are subject to Chapleau PUC's inspection/acceptance.

The Customer is responsible to maintain all its structural and mechanical facilities on private property in a safe condition satisfactory to Chapleau PUC.

The Customer will be responsible for Chapleau PUC's costs associated with re-design and inspection services due to changes or deviations initiated by the Customer or its agents or any other body having jurisdiction.
It is the responsibility of the owner or his/her contractor to obtain clearances from all of the utility companies before digging.

It is the responsibility of the owner to contact Chapleau PUC to inspect each trench prior to the installation of Chapleau PUC's cables.

3.2.3 Temporary Services (other than Residential)

A temporary service is a normally metered service provided for construction purposes or special events. Temporary services can be supplied overhead or underground. The Customer will be responsible for all associated costs for **the installation and removal** of equipment required for a temporary service to Chapleau PUC's point of supply. Temporary services may be provided for a period of no more than 12 months. Temporary services must be renewed thereafter if an extension is required and the equipment for such temporary service must be reinspected at the end of the 12-month period.

Subject to the requirements of Chapleau PUC, supply will be connected after receipt of a 'Connection Authorization' from the Electrical Safety Authority.

Where meter bases are required, they must be approved by Electrical Safety Authority and shall be securely mounted on minimum 152 mm diameter poles so that the midpoint of the meter is 1.73 m (± 100 mm) from finished grade.

In the case of temporary overhead services, the Customer shall leave 760 mm of cable at the masthead for connection purposes.

In the case of temporary underground services, the Customer's cable shall extend to Chapleau PUC's point of supply.

3.3 General Service (Above 50 kW)

All non-residential Customers with an average peak demand between 50 kW and 999 kW over the past twelve months are to be classified as General Services above 50 kW. For new Customers without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer.

3.3.1 Electrical Requirements

Where the size of the Customer's electrical service warrants, the Customer will be required to provide facilities on its property and an easement as required (i.e. on the premises to be served), acceptable to Chapleau PUC, to house the necessary transformer(s) and/or switching equipment. Chapleau PUC will provide planning details upon application for service.

Chapleau PUC will supply, install and maintain the electrical transformation equipment within the transformer vault or pad. Chapleau PUC has the right to have this equipment connected to its distribution system.

The owner is required to supply and maintain an electrical room of sufficient size to accommodate the service entrance and meter requirements of the tenants and provide clear working space in accordance with the Ontario Electrical Safety Code.

The electrical room shall not be used for storage or contain equipment foreign to the electrical installation within the area designated as safe working space. All stairways leading to electrical rooms above or below grade shall have a handrail on at least one side as per the Ontario Building Code, and shall be located indoors.

The owner shall identify each Customer's metered service by address and/or unit number in a permanent and legible manner. The identification shall apply to all main switches, breakers and to all meter cabinets or meter mounting devices that are not immediately adjacent to the switch or breaker. The electrical room shall be visibly identified from the outside.

3.4 Unmetered Connections

3.4.1 Street Lighting

All services supplied to street lighting equipment owned by or operated for a municipality or the Province of Ontario shall be classified as Street Lighting Service. For rate structure details refer to Chapleau PUC's Distribution Rate Order Application.

Street Lighting plant, facilities, or equipment owned by the Customer are subject to the Electrical Safety Authority (ESA) requirements.

Street lights belonging to the Municipality are maintained and newly installed on an hourly basis according to Chapleau PUC's rates.

Ownership demarcation point will be line side of fuse, if no fuse, point of connection on Distributor's feed pole/lines.

3.4.2 Traffic Signals and Pedestrian X-Walk Signals/Beacons

Traffic signals and pedestrian x-walk signals/beacons are billed flat rate unless metered. Christmas lights are billed flat rate one time per year, and varies depending on the number of lights installed that year.

Ownership demarcation point will be top of Customer's service mast, if overhead.

For new services, there exists a $20.00 connection fee. Re-design and inspection services are at the expense of the Customer. The Customer is responsible for the

cost to maintain and repair the equipment.

4 SECTION 4 GLOSSARY OF TERMS

Sources for definitions:

A Electricity Act, 1998, Schedule A, Section 2, Definitions
MR Market Rules for the Ontario Electricity Market, Chapter 11, Definitions
TDL Transitional Distribution License, Part 1, Definitions
TTL Transitional Transmission License, Part 1, Definitions
DSC Distribution System Code Definitions
RSC Retail Settlement Code Definitions

"Accounting Procedures Handbook" means the handbook approved by the Board and in effect at the relevant time, which specifies the accounting records, accounting principles and accounting separation standards to be followed by the distributor;
(TDL, DSC)

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;
(TDL, DSC)

"ancillary services" means services necessary to maintain the reliability of the IMO-controlled grid; including frequency control, voltage control, reactive power and operating reserve services;
(MR, TDL, DSC)

"apartment building" means a structure containing four or more dwelling units having access from an interior corridor system or common entrance;

"apparent power" means the total power measured in kilo Volt Amperes (kVA);

"application for service" means the agreement or contract with Chapleau PUC under which electrical service is requested;

"bandwidth" means a distributor's defined tolerance used to flag data for further scrutiny at the stage in the VEE (validating, estimating and editing) process where a current reading is compared to a reading from an equivalent historical billing period. For example, a 30 percent bandwidth means a current reading that is either 30 percent lower or 30 percent higher that the measurement from an equivalent historical billing period will be identified by the VEE process as requiring further scrutiny and verification;
(DSC)

"billing demand" means the metered demand or connected load after necessary adjustments have been made for power factor, intermittent rating, transformer losses and minimum billing. A measurement in kilo Watts (kW) of the maximum rate at which electricity is consumed during a billing period;

"Board" or "OEB" means the Ontario Energy Board;

(A, TDL, DSC)

“building” means a building, portion of a building, structure or facility;

“complex metering installation” means a metering installation where instrument transformers, test blocks, recorders, pulse duplicators and multiple meters may be employed;
(DSC)

“Conditions of Service” means the document developed by a distributor in accordance with subsection 2.4 of the Code that describes the operating practices and connection rules for the distributor;
(DSC)

“connection” means the process of installing and activating connection assets in order to distribute electricity to a Customer;
(DSC)

“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 that connection;
(DSC)

“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 distributor’s main distribution system and the ownership demarcation point with that Customer;
(DSC)

“Consumer” means a person who uses, for the person’s own consumption, electricity that the person did not generate;
(A, MR, TDL, DSC)

“Customer” means a person that has contracted for or intends to contract for connection of a building. This includes developers of residential or commercial subdivisions;
(DSC)

“demand” means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes;
(DSC)

“demand meter” means a meter that measures a Consumer’s peak usage during a specified period of time;
(DSC)

“developer” means a person or persons owning property for which new or modified electrical services are to be installed;

“disconnection” means a deactivation of connection assets that results in cessation of distribution services to a Consumer;
(DSC)

“distribute” with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less;
(A, MR, TDL, DSC)

“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; (DSC)
“distribution loss factor” means a factor or factors 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;
(RSC)

“distribution services” means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under section 78 of the Ontario Energy Board Act;
(RSC, DSC)

“distribution system” 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;
(A, MR, TDL, DSC)

“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 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;
(TDL, DSC)

“distributor” means a person who owns or operates a distribution system;
(A, MR, TDL, DSC)

“duct bank” means two or more ducts that may be encased in concrete used for the purpose of containing and protecting underground electric cables;

“Electricity Act’ means the Electricity Act, 1998, S.O. 1998, c.15, Schedule A;
(MR, TDL, DSC)

“Electrical Safety Authority” or “ESA” means the person or body designated under the Electricity Act regulations as the Electrical Safety Authority;
(A)

“electric service” means the Customer’s conductors and equipment for energy from Chapleau PUC;

“emergency” means any abnormal system condition that requires remedial action to prevent or limit loss of a distribution system or supply of electricity that could adversely affect the reliability of the electricity system;
(DSC)

“emergency backup” means a generation facility that has a transfer switch that isolates it from a distribution system;
(DSC)

“energy” means the product of power multiplied by time, usually expressed in kilowatt-hours (kWH);

“Energy Competition Act” means the Energy Competition Act, 1998, S.O. 1998, c.15; (MR)

“energy diversion” means the electricity consumption unaccounted for but that can be quantified through various measures upon review of the meter mechanism, such as unbilled meter readings, tap off load(s) before revenue meter or meter tampering;

“enhancement” means a modification to an existing distribution system that is made for purposed of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting, for example, from general load growth;
(DSC)

“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;
(DSC)

“extreme operating conditions” means extreme operating conditions as defined in the Canadian Standards Association (“CSA”) Standard CAN3-C235-87 (latest edition);

“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;
(DSC)

“general service” means any service supplied to premises other than those designated as Residential and less than 50 kW, Large User, or Municipal Street Lighting. This includes multi-unit residential establishments such as apartments buildings supplied through one service (bulk-metered);

“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;
(A, TDL, DSC)

“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;
(A, MR, TDL, DSC)

“generator” means a person who owns or operates a generation facility;
(A, MR, TDL, DSC)

“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;
(DSC)

“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 judgement 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;
(MR, DSC)

“host distributor” means the registered wholesale market participant distributor who provides electricity to an embedded distributor;
(RSC, DSC)

“house service” means that portion of the electrical service in a multiple occupancy facility which is common to all occupants, (i.e. parking lot lighting, sign service, corridor and walkway lighting, et cetera);

“IEC” means International Electrotechnical Commission;

“IEEE” means Institute of Electrical and Electronics Engineers;

“IMO” means the Independent Electricity Market Operator established under the Electricity Act;
(A, TDL, DSC)

“IMO-controlled grid” means the transmission systems with respect to which, pursuant to agreements, the IMO has authority to direct operation;
(A, TDL, DSC)

“interval meter” means a meter that measures and records electricity use on an hourly or sub-hourly basis;
(RSC, DSC)

“large user” means a Customer with a monthly peak demand of 5000 kW or greater, regardless the demand occurs in the peak or off-peak periods, averaged over 12 months;

“load factor” means the ratio of average demand for a designated time period (usually one month) to the maximum demand occurring in that period;

“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;
(DSC)

“load transfer Customer” means a Customer that is provided distribution services through a load transfer;
(DSC)
“main service” refers to Chapleau PUC’s incoming cables, bus duct, disconnecting and protective equipment for a Building or from which all other metered sub-services are taken;

“Market Rules” means the rules made under section 32 of the Electricity Act;
(MR, TDL, DSC)

“Measurement Canada” means the Special Operating Agency established in August 1996 by the

Electricity and Gas Inspection Act, 1980-81-82-83, c.87., and Electricity and Gas Inspection Regulations (SOR/86-131);
(DSC)

“meter service provider” means any entity that performs metering services on behalf of a distributor;
(DSC)

“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;
(RSC, DSC)

“meter socket” means the mounting device for accommodating a socket type revenue meter;

“metering services” means installation, testing, reading and maintenance of meters;
(DSC)

“MIST meter” means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to “Metering Inside the Settlement Timeframe”;
(RSC, DSC)

“MOST meter” means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to “Metering Outside the Settlement Timeframe”;
(RSC, DSC)

“multiple dwelling” means a Building which contains more than one self-contained dwelling unit;

“municipal street lighting” means all services supplied to street lighting equipment owned and operated for a municipal corporation;

“non-competitive electricity costs” means costs for services from the IMO that are not deemed by the Board to be competitive electricity services plus costs for distribution services, other than Standard Supply Service (SSS);
(RSC)

“normal operating conditions” means the operating conditions comply with the standards set by the Canadian Standards Association (“CSA”) Standard CAN3-C235-87 (latest edition);

“Ontario Energy Board Act” means the Ontario Energy Board Act, 1998, C. O. 1998, c.15, Schedule B;
(MR, DSC)

“operational demarcation point” means the physical location at which a distributor’s responsibility for operational control of distribution equipment including connection assets ends at the Customer;
(DSC)

“ownership demarcation point” means the physical location at which a distributor’s ownership of distribution equipment including connection assets ends at the Customer;
(DSC)

“performance standards” means the performance targets for the distribution and connection

activities of the distributor as established by the Board pursuant to the Ontario Energy Board Act and in the Rate Handbook;
(DSC)

"person" includes an individual, a corporation, sole proprietorship, partnership, unincorporated organization, unincorporated association, body corporate, and any other legal entity;

"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;
(DSC)

"plaza" means any Building containing two or more commercial business tenants;

"point of supply" with respect to an embedded generator, means the connection point where electricity produced by the generator is injected into a distribution system;
(DSC)

"power factor" means the ration between Real Power and Apparent Power (i.e. kW/kVA);

"primary service" means any service which is supplied with a nominal voltage greater than 750 volts;

"private property" means the property beyond the existing public street allowances;

"rate" means any rate, charge or other consideration, and includes a penalty for late payment;
(TDL, DSC)

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

"reactive power" means the power component which does not produce work but is necessary to allow some equipment to operate, and is measured in kilo Volt Amperes Reactive (kVAR);

"real power" means the power component required to do real work, which is measured in kilo Watts (kW);

"Regulations" means the regulations made under the *Ontario Energy Board Act* or the *Electricity Act*;
(TDL, DSC)

"residential service" means a service which is less than 50 kW supplied to single-family dwelling units that is for domestic or household purposes, including seasonal occupancy. At Chapleau PUC's discretion, residential rates may be applied to apartment buildings with 6 or less units by simple application of the residential rate or by blocking the residential rate by the number of units;

"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;

(A, MR, TDL, DSC)

“Retail Settlement Code” means the code approved by the Board and in effect at the relevant time, 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 Consumers transfers among competitive retailers; (TDL, DSC)

“retailer” means a person who retails electricity;
(A, MR, TDL, DSC)

“secondary service” means any service which is supplied with a nominal voltage less than 750 Volts;

“service agreement” means the agreement that sets out the relationship between a licensed retailer and a distributor, in accordance with the provisions of Chapter 12 of the Retail Settlement Code;
(RSC)

“service area” with respect to a distributor, means the area in which the distributor is authorized by its license to distribute electricity;
(A, TDL, DSC)

“service date” means the date that the Customer and Chapleau PUC mutually agree upon to begin the supply of electricity by Chapleau PUC;

“Standard Supply Service Code” means the code approved by the Board and in effect at the relevant time, 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;
(TDL)

“sub-service” means a separately metered service that is taken from the main Building service;

“supply voltage” means the voltage measured at the Customer’s main service entrance equipment (typically below 750 volts). Operating conditions are defined in the Canadian Standards Association (“CSA”) Standard CAN3-C235 (latest edition);

“temporary service” means an electrical service granted temporarily for such purposes as construction, real estate sales, trailers, et cetera;

“terminal pole” refers to the Chapleau PUC’s distribution pole on which the service supply cables are terminated;
“total loss” means the sum of distribution losses and unaccounted for energy;
(DSC)

“transformer room” means an isolated enclosure built to applicable codes to house transformers and associated electrical equipment;

“transmission system” means a system for transmitting electricity, and includes any structures, equipment or other things used for that purpose;
(A, MR, TDL, DSC)

“Transmission System Code” means the code, approved by the Board, that is in force at the relevant time, which regulates the financial and information98obligations 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;
(DSC)

“transmit”, with respect to electricity, means to convey electricity at voltages of more than 50 kilovolts;
(A, TDL, DSC)

“transmitter” means a person who owns or operates a transmission system;
(A, MR, TDL, DSC)

“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 unmetered loads, energy theft and non-attributable billing errors;
(DSC)

“unmetered loads” means electricity consumption that is not metered and is billed based on estimated usage; (DSC)

“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;
(MR, DSC)

“wholesale buyer” means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator;
(TDL, DSC)

“wholesale market participant”, means a person that sells or purchases electricity or ancillary services through the IMO-administered markets;
(RSC, DSC)

“wholesale settlement cost” means costs for both competitive and non-competitive electricity services billed to a distributor by the IMO or a host distributor, or provided by an embedded retail generator or by a neighboring distributor;
(RSC, DSC)

“wholesale supplier” means a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person, other than a ‘Consumer;
(TDL, DSC)

TABLE 1

Type	Ownership Demarcation Point	Basic Connections	Service Charge and Basic Connection Fee (Reviewed (Annually)	Additional Services Charged Customer
Class 1 Residential Single Service				
Overhead	Top of Customer's Service Mast.		Does not include street crossing. Includes connections on distributor's system and line side of customer meter socket	$19.92/month service charge connection fee $65.00
U/G	Line side of Customer's meter base	Connections to Customer's stack and to feed pole or lines of Utility.	$19.92/month service charge connection fee $65.00	

Customer requesting U/G service in O/H area will be required to pay 100% connection costs, less basic	connections ESA. Cost covered by customer.			

Class 2 General Service 0 - 50 kW

			ownership .60/kw	Service charge $31.17. Basic connection fee $65.00
Overhead Single Service				
	Top of Customer's service mast. or to overhead transformer bank if secondary underground			
U/G Single Service		Includes connections on distributor's feed pole or lines at customer's service mast. Allowance for customer owned transformer .60/kw	Service charge $31.17. Basic connection fee $65.00	
	Connection to padmount owned by the Utility or not			
		Includes connection on distributor's system. Does not include street crossing. Allowance for transformer		Additional or redesign due to changes in initial proposal. ESA inspections cost covered by customer

	Additional or redesign due to changes in initial proposal. ESA inspections costs covered by customer			

Class 3 General Service > 50 kW

Overhead single building			customer transformer. Transformer ownership allowance .60/kW	Service charge $152.79 Connection fee $65.00
Single building	Top of customer's service mast or if underground service at transformer bank	Connections on distributor's system and customer's service mast. Customer owned transformer .60/kW	Service charge $152.79 Connection fee $65.00	
	Connection to padmount transformer Utility owned or not	Does not include street crossing. Includes connection on distribution system and		Additional or redesign due to changes in customer's initial proposal. ESA inspections

covered by customer	Additional or redesign due to changes in customer's initial proposal. ESA inspections covered by customer			

TABLE 2

INSTRUMENT TRANSFORMERS AND CHAMBERS						
Voltage	Phase	Wire	Service Size (Amperes)	Compartment Size	Number of Instrument Transformers	
					Current	Voltage

120/4200	1	3	Up to 800	A	1 or 2
			Over 800	B	
208/120			Up to 800	B	3
416/2403	3	4			
600/347			Over 800	D	3
600	3	3	Up to 800	A	2
			Over 800	C	2

COMPARTMENT SIZES (width x height x depth)

A	-	762 mm x 762 mm x 305 mm	(30” x 30” x 12”)
B	-	762 mm x 762 mm x 381 mm	(30” x 30” x 15”)
C	-	762 mm x 914 mm x 381 mm	(30” x 36” x 15”)
D	-	914 mm x 914 mm x 457 mm	(36” x 36” x 18”)
	or	762 mm x 1067 mm x 457 mm	(30” x 42” x 18”)

NOTES:

1. Instrument transformers will be supplied by the Customer and shall be installed in the switch gear
by the manufacturer. The manufacturer shall not disassemble and/or change in any manner the
Chapleau Public Utilities Corporation’s equipment sent to the manufacturer.

2. Voltage transformer connections shall be connected on the line side of the current transformers.
Current transformers shall be installed with their polarity marks towards the incoming Chapleau Public Utilities Corporation’s supply.

TABLE 3

SELF-CONTAINED SOCKET METERING

Maximum Service Voltage	Phase	Wire	Switch Size Rating Amperes
120/240	1	3	200
120/240 *	1	3	400
208/120	3	4	200
600/347	3	4	200

*Meter socket contains a 3 wire current transformer and transformer type meter.

Notes: 1. A list of approved meter sockets is available upon request.

2. Meter sockets shall be mounted so that the midpoint of the meter is set at 1700 mm $\pm$ 100 mm.

3. Where the supply is grounded, 600 V. metering shall be 4 wire. Where the

Customer does not require a neutral, 1 full size neutral conductor sized in accordance with Table 17 of the Ontario Electrical Safety Code must be provided to all meter cabinets or sockets. The neutral conductor is to be terminated in the socket (or cabinet) on an insulated block in accordance with the Ontario Electrical Safety Code.

TABLE 4

Meter centres may be used for 750 V applications or less, as far as they meet the following
specifications:

1) Side-hinged doors or panels shall be installed over all sections of the switchboard where Chapleau PUC may be required to work, such as unmetered sections and those sections containing breakers, switches and meter mounting devices. Hinged doors or panels shall have provision for sealing and padlocking in the closed position.
2) Breakers or switch handles shall have provision for positive sealing and padlocking in the "off" position.
3) Meter mounting devices shall be wired so as to be on the "load" side of the breakers or switches.
4) Each combination meter socket and breaker panel shall have adequate space for permanent Customer identification with respect to street address and/or unit number.
5) The centre of the bottom row of meter sockets shall be not less than 600 mm from the finished floor. The centre of the top row of meter sockets shall be not less than 1800 mm

from the finished floor.

6) The distance between adjacent meter socket rims in the horizontal plane shall not be less than 152 mm.

7) The distance between adjacent meter socket rims in the vertical plane shall be as follows:
   a) For 100 A., 4 or 5 jaw, not less than 76 mm.
   b) For 100 A., 7 jaw, not less than 152 mm.

8) The meter mounting socket and sealing ring shall be acceptable to Chapleau PUC.

9) Where a neutral is required, the meter mounting device shall have a pre-wired, ungrounded neutral connection to the 5^{th} or 7^{th} terminal. The connection, if not made directly to the neutral bus, shall be not less than #12 AWG copper or equivalent.

Section 6 - REFERENCES

1. Conditions of Service Toronto Hydro Electric System Limited.

Financial Statements of

CHAPLEAU PUBLIC UTILITIES CORPORATION

Year ended December 31, 2006

KPMG LLP
Chartered Accountants
Claridge Executive Centre
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Sudbury ON P3E 4R6

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AUDITORS' REPORT

To the Shareholder of Chapleau Public Utilities Corporation

We have audited the balance sheet of **Chapleau Public Utilities Corporation** as at December 31, 2006 and the statements of earnings and deficit 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.

In our opinion, 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 its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Sudbury, Canada
April 25, 2007

CHAPLEAU PUBLIC UTILITIES CORPORATION

Balance Sheet

December 31, 2006, with comparative figures for 2005

	2006	2005 (restated)
Assets		
Current assets:		
Cash	$ 173,608	$ 495,139
Term deposits and treasury bills	651,121	527,563
Trade receivables (note 2)	40,885	30,175
Plant materials and supplies - at cost	43,787	29,309
Prepaid expenses	10,318	9,200
Unbilled revenue - energy sales	424,856	449,301
Unbilled revenue - distribution	42,940	70,187
	1,387,515	1,610,874
Capital assets (note 3)	2,175,939	2,151,646
Less accumulated amortization	1,266,778	1,229,408
	909,161	922,238
	$ 2,296,676	$ 2,533,112
Liabilities and Shareholder's Deficiency		
Current liabilities:		
Accounts payable and accrued liabilities (note 4)	$ 267,048	$ 542,373
Accrued interest payable	-	203,905
Advances from related company (note 5)	20,551	121,903
	287,599	868,181
Other liabilities:		
Regulatory liabilities (note 6)	487,538	461,498
Customer deposits	21,989	27,259
Loan payable (notes 7 and 15)	360,727	717,560
Mortgage payable (notes 8 and 15)	1,321,493	1,321,493
Shareholder's deficiency:		
Share capital (note 9)	560,840	100
Deficit	(743,510)	(862,979)
	(182,670)	(862,879)
Commitments (note 12)		
Contingencies (note 13)		
Subsequent events (note 15)		
	$ 2,296,676	$ 2,533,112

See accompanying notes to financial statements.

On behalf of the Board:

_____ Director

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Earnings and Deficit

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005 (restated)
Revenue:		
Energy sales	$ 2,089,075	$ 2,143,133
Distribution	567,925	494,734
	2,657,000	2,637,867
Expenses:		
Power purchased	2,043,433	2,185,831
Operations and maintenance	262,647	291,278
Administration and general	164,663	181,879
Billing and collection	63,918	52,929
Amortization of capital assets	37,370	37,731
	2,572,031	2,749,648
Earnings (loss) before the undernoted	84,969	(111,781)
Other income (expenses):		
Interest earned	48,509	25,730
Late payment charges	4,684	5,091
Miscellaneous	17,421	8,459
Other interest	(36,114)	(51,351)
Chargebacks (note 11)	-	(46,540)
Interest on loans and mortgage payable (note 11)	-	(203,905)
	34,500	(262,516)
Net earnings (loss) for the year	119,469	(374,297)
Deficit, beginning of year	(862,979)	(488,682)
Deficit, end of year	$ (743,510)	$ (862,979)

See accompanying notes to financial statements.

CHAPLEAU PUBLIC UTILITIES CORPORATION

Statement of Cash Flows

Year ended December 31, 2006, with comparative figures for 2005

	2006	2005 (restated)
Cash provided by (used in):		
Operations:		
Net earnings (loss) for the year	$ 119,469	$ (374,297)
Item not involving cash:		
Amortization of capital assets	37,370	37,731
	156,839	(336,566)
Change in non-cash operating working capital:		
Increase in trade receivables	(10,710)	(1,799)
Decrease (increase) in plant materials and supplies - at cost	(14,478)	2,242
Decrease (increase) in prepaid expenses	(1,118)	1,262
Decrease (increase) in unbilled revenue - energy sales	24,445	(12,692)
Decrease (increase) in unbilled revenue - distribution	27,247	(1,046)
Increase (decrease) in accounts payable and accrued liabilities	(275,325)	231,617
Increase (decrease) in accrued interest payable	(203,905)	18,537
Decrease in customer deposits	(5,270)	(8,210)
Decrease in payment in lieu of taxes	-	4,000
Increase in advances from related company	-	10,480
	(302,275)	(92,175)
Financing:		
Decrease in advances from related company	(101,352)	-
Increase (decrease) loan payable	(356,833)	185,368
Issue of share capital	560,740	-
	102,555	185,368
Investments:		
Addition to capital assets	(24,293)	(33,080)
Increase in regulatory liabilities	26,040	172,549
	1,747	139,469
Increase (decrease) in cash position	(197,973)	232,662
Cash position, beginning of year	1,022,702	790,040
Cash position, end of year	$ 824,729	$ 1,022,702
Cash and cash equivalents are represented by:		
Cash	$ 173,608	$ 495,139
Term deposits and treasury bills	651,121	527,563
	$ 824,729	$ 1,022,702
Supplemental cash flow information:		
Interest paid	$ 203,905	$ 185,368

See accompanying notes to financial statements.

Chapleau Public Utilities Corporation (the "Corporation") was incorporated August 18, 1999 to operate as an electricity distribution company.

1. Significant accounting policies:

(a) General:

These financial statements are the representation's of the Corporation's management and are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and policies set forth in the Accounting Procedure Manual issued by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998 ("OEBA"). The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. In its capacity to set or approve rates, the OEB has the authority to specify regulatory treatments that may result in accounting treatments that differ from Canadian GAAP for enterprises operating in a non-rate regulated environment.

The Electricity Act, 1998 (Ontario) ("Electricity Act") provides for a competitive marketplace in the sale of electricity. The marketplace was deregulated effective May 1, 2002.

(b) Revenue recognition and power purchased:

Revenue is recorded in the accounts to various dates on the basis of monthly or bi-monthly meter readings. At the end of an accounting cycle, there is energy used by consumers for which meter readings are not available. The unbilled revenue is estimated and recorded in the accounts at the end of each fiscal year. The related cost of energy is recorded on the basis of energy used.

(c) Effects of rate regulation:

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in a non rate-regulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting and approval process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting and approval process.

1. Significant accounting policies (continued):

(d) Capital assets:

Capital assets are stated at cost. Amortization is provided using the following methods and annual rates:

Asset	Basis	Rate
Transmission and distribution systems	Declining-balance	25 - 40 years

(e) Payment in lieu of taxes:

Effective October 1, 2001 and pursuant to the Electricity Act, the Corporation is required to compute taxes under the Income Tax Act (Canada) and Ontario Corporations Tax Act and remit such amounts computed thereunder to the Ontario Electricity Financial Corporation ("OEFC"). These amounts, referred to as payments in lieu of taxes ("PILs") under the Electricity Act, are applied to reduce certain debt obligations of the former Ontario Hydro now owed by the OEFC.

The Corporation provides for amounts in lieu of income taxes using the taxes payable method. Under the taxes payable method, no provision is made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in rates approved by the OEB and recovered from customers at that time.

(f) Asset retirement obligations:

During 2004, the Corporation adopted the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3110, Asset Retirement Obligations. This accounting standard requires the Corporation to determine the fair value of the future expenditures required to settle legal obligations to remove capital assets. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated capital asset.

Some of the Corporation's transmission and distribution assets may have asset retirement obligations. As the Corporation expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Corporation is legally required to remove, an asset retirement obligation will be recognized at that time.

1. Significant accounting policies (continued):

(g) Use of estimates:

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates.

2. Trade receivables:

	2006	2005
Electrical	$ 50,785	$ 36,175
Provision for doubtful accounts	(9,900)	(6,000)
	$ 40,885	$ 30,175

3. Capital assets:

			2006	2005
	Cost	Accumulated amortization	Net book value	Net book value
Land	$ 141	$ -	$ 141	$ 141
Transmission and distribution systems	2,175,798	1,266,778	909,020	922,097
	$ 2,175,939	$ 1,266,778	$ 909,161	$ 922,238

4. Accounts payable and accrued liabilities:

	2006	2005
Power purchased	$ 224,317	$ 303,889
Miscellaneous	42,731	238,484
	$ 267,048	$ 542,373

5. Advances from related company:

The amounts advanced from related company are non-interest bearing, unsecured and have no specified terms of repayment. The Corporation is related by virtue of common ownership.

6. Regulatory liabilities:

Net regulatory liabilities represent costs incurred by the Corporation less amounts billed to the consumer at OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future recovery in electricity distribution rates. Management assesses the future uncertainty with respect to the final regulatory disposition of those amounts and the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

	2006	2005
Deferred transition costs (a)	$ 33,943	$ 54,718
Retail settlement variances (b)	(518,187)	(454,121)
Pre-market opening energy variances (c)	-	(42,085)
Deferred payments in lieu of taxes (d)	(3,294)	(20,010)
	$ (487,538)	$ (461,498)

(a) Deferred transition costs - the OEB established a process for the recording of costs incurred by the Corporation to be market ready, including related carrying costs, as deferred transition costs to be recovered in the future through the regulatory rate-setting process. In the absence of rate regulation, Canadian GAAP would require that the costs be recognized as an expense or capital asset, as applicable, when incurred. The Corporation filed for recovery of these costs in March 2005 and were granted final approval for recovery of these costs over a three year period.

(b) Retail settlement variances - represent the difference between the amount paid by the Corporation to the Independent Market System Operator ("IESO") for the cost of energy and the amount billed by the Corporation to its customers as energy sales, and related carrying costs which are recorded on the balance sheet as retail settlement variances until their final disposition is decided by the OEB. The Corporation recognizes retail settlement variances as as an asset or liability based on the expectation these amounts will be approved by the OEB for future collection from, or refund to, customers through the rate setting and approval process. The retail settlement variance liability represents the deficiency of amounts billed by the IESO for the cost of energy compared to the amounts charged to customers as energy sales. In the absence of rate regulation, Canadian GAAP would require that the total cost of energy be charged to operations when incurred and the total amount of energy sales be credited to operations when earned.

6. Regulatory liabilities (continued):

(c) Pre-market opening energy variances - represent the difference between the cost of energy purchased and the amounts billed to customers prior to Market Opening. The Corporation filed for recovery of these costs in March 2005 and were granted final approval for recovery of these costs in 2006.

(d) Deferred payments in lieu of taxes - represent variances that result from the difference between OEB approved PILs recoverable in electricity distribution service charges and the actual amount of these charges to customers that relates to the recovery of PILs.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Corporation may charge and the costs that the Corporation may recover, including the balance of its regulatory assets.

In the absence of rate regulation, Canadian GAAP would require the Corporation to record the costs and recoveries described above in the operating results of the year in which they are incurred and reported earnings before income taxes would be $16,716 (2005 - ($20,010)) lower than reported.

For certain of the regulatory assets and liabilities identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the OEB in determining the item's treatment for rate-setting purposes. The Corporation continually assesses the likelihood of recovery of each of its regulatory assets and refund each of its regulatory liabilities and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If at some future date the Corporation determines that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be charged to operations in the period the determination is made.

7. Loan payable:

The loan is repayable to the Corporation of the Township of Chapleau (the "Township"). The loan bears interest at 7.25%, is unsecured and has no specified terms of repayment. Payment of interest has been postponed indefinitely and the Township has indicated they will not demand repayment within the next twelve months.

During the year, the Corporation converted $560,740 of the loan payable into common shares of the Corporation.

8. Mortgage payable:

The mortgage payable is repayable to the Township, is secured by a general security agreement and specific assets of the Corporation, bears interest at 7.25% and has no specified terms of repayment. Payment of interest has been postponed indefinitely and the Township has indicated they will not demand repayment within the next twelve months.

9. Share capital:

	2006	2005
Authorized:		
Unlimited common shares		
Issued:		
560,840 common shares		
(2005 - 100 common shares) (note 7)	$ 560,840	$ 100

10. Payment in lieu of taxes:

For payment in lieu of tax purposes, the Corporation has losses of $728,423 carried forward which can be applied to reduce future years' taxable income. These losses will expire as follows:

2010	$ 128,130
2011	296,896
2012	303,397

11. Related party transactions:

The Corporation is related to the Township by virtue of the fact that the Township is the sole shareholder of the Corporation. The Corporation is related to Chapleau Energy Services Corporation by virtue of common ownership.

During the year, the Corporation was charged $Nil (2005 - $203,905) of interest by the Township and billed the Township $286,995 (2005 - $272,606) for power purchased.

Also, the Corporation was charged $Nil (2005 - $46,540) by Chapleau Energy Services Corporation, for the Corporation's portion of certain shared costs.

During the year, the Corporation paid $1,181 (2005 - $1,240) to the Township on account of municipal taxes.

12. Commitments:

The Corporation has issued a $300,205 Letter of Credit to the IMO for market opening on May 1, 2002. At December 31, 2006, no amounts have been drawn on this financing arrangement.

13. Contingencies:

A class action lawsuit claiming $500 million in restitutionary payments plus interest was served on the former Toronto Hydro Electric Commission, continuing as Toronto Hydro Corporation, on November 8, 1998. This action was initiated against the former Toronto Hydro Electric Commission as the representative of the defendant class consisting of all municipal electric utilities in Ontario which have charged late payment charges on overdue utility bills after April 1, 1981.

The claim is that late payment penalties result in municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under section 347(1)(b) of the Criminal Code. The Electricity Distributors Association has undertaken the defence of this class action. At this time it is not possible to quantify the effect, if any, on the financial statements.

Accordingly, no provision has been made in these financial statements with respect to any possible losses that may arise as a result of this matter.

14. Financial instruments:

Fair value of financial assets and financial liabilities

The carrying value of cash, trade receivable, unbilled revenue, term deposits and treasury bills, accounts payable and accrued liabilities, accrued interest payable, advances from related company and customer deposits approximate their fair value due to the relatively short periods to maturity of these items.

It was not practicable to estimate the fair value of the loan payable and mortgage payable as there are no principal repayment terms.

15. Subsequent events:

Subsequent to year-end, the Corporation passed a resolution authorizing the conversion of $360,727 of the loan payable and $199,813 of the mortgage payable owing to the Township into common shares of the Corporation.

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

Balance Sheet

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672
		-	-

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

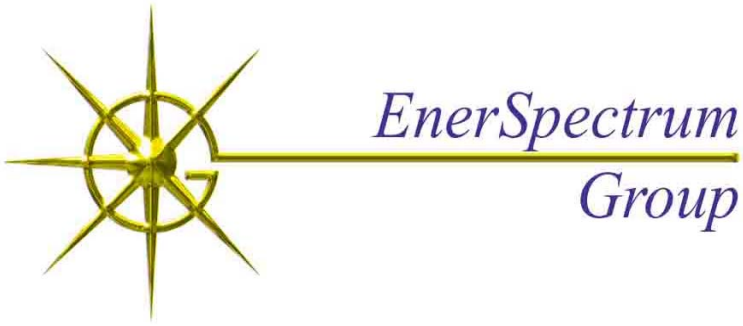
EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006	2006	Bridge Year	Test Year	Forecast
	Historical Board Approved	Historical Actual	2007	2008	2009
Revenue					
Distribution Revenue	$ 605,891	$ 567,925	$ 592,434	$ 680,023	$ 723,158
SSS Admin. and Retailer Charges	$ -	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,681	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	0	$ -	$ -	$ 24,631	$ 36,947
Revenue	$ 648,572	$ 611,964	$ 646,473	$ 749,633	$ 798,640
Operations and Maintenance	$ 263,311	$ 262,647	$ 296,913	$ 302,585	$ 308,637
Billing & Collecting	$ 65,879	$ 63,918	$ 66,539	$ 64,112	$ 66,035
Depreciation	$ 37,890	$ 37,370	$ 36,273	$ 36,563	$ 42,977
Administrative and General Expenses					
Community Relations	$ 2,607	$ 1,707	$ 1,063	$ 1,200	$ 1,200
Executive Salaries and Expense	$ 59,881	$ 59,331	$ 62,672	$ 64,552	$ 66,489
Office Supplies and Expense	$ 22,176	$ 19,432	$ 21,661	$ 22,248	$ 22,915
Outside Services Employed	$ 38,352	$ 47,795	$ 109,238	$ 60,820	$ 60,000
Property Insurance	$ 13,601	$ 12,119	$ 13,000	$ 13,500	$ 18,000
Regulatory Expenses	$ 5,734	$ 4,584	$ 5,769	$ 6,000	$ 12,000
Misc. General Expenses	$ 6,546	$ 10,612	$ 15,000	$ 12,000	$ 12,000
Bank Charges	$ 8,247	$ 8,941	$ 9,883	$ 9,200	$ 10,000
Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ 24,631	$ 36,947
Total Expenses	$ 524,224	$ 528,456	$ 638,011	$ 617,411	$ 657,200
Income (Loss)	$ 124,348	$ 83,508	$ 8,462	$ 132,222	$ 141,440
Interest Payable to Township of Chapleau	$ 48,454	$ -	$ -	$ 87,328	92207
Net Income (Loss)	$ 75,894	$ 83,508	$ 8,462	$ 44,894	$ 49,233

Cash Flow Forecast 2008 to 2012	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437
Net Income (Loss)	$ 8,462	$ 44,894	$ 49,000	$ 45,000	$ 45,000	$ 45,000
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (28,935)	$ (101,023)	$ (101,023)	$ (101,023)	$ (33,674)
Change in Accounts Reaceivable	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437	$ 515,654

APPENDIX D



Chapleau Public Utilities Corporation
Distribution System

System Analysis for Loss Optimization
E1059

September, 2007

Prepared by: Soheil Ebrahimzadeh, Distribution System Analyst
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Introduction

As part of its Conservation and Demand Management Plan, Chapleau PUC has identified an opportunity to reduce system losses and optimize performance on its distribution system. Prudently, the LDC has taken as its first action to commission a study of both its' 4.16 kV and 25 kV distribution system to provide a platform for optimizing value for future investments and expenditures to mitigate losses.

Chapleau PUC's distribution system is geographically captured on a drafted electronic Autocad geographic base with general system layout, feeders and loads spatially positioned. Although this formed a good base for geographic reference, the information contained therein required significant data acquisition and refreshing including:

- Capture of as-is system components
- Feeder characteristics (voltage, phasing, conductor size)
- Feeder loading measured at supply points
- Configuration updates to match actual field conditions

Despite the significant effort to gather and validate the required data, Chapleau PUC recognized the value of the investment in this work to ensure not only a valid base for accurate analyses at this time, but also to enable future assessment of system optimization opportunities.

Services Commissioned

Chapleau PUC commissioned EnerSpectrum Group to complete system modeling, assessments, and Total Resource Cost (TRC) analysis within the following scope:

1. Construct an accurate system model of Chapleau PUC suitable for analysis with Dromey Distribution Engineering Simulation Software (DESS). This includes modeling all overhead and underground lines, distribution transformers, switches, station transformers and primary supply lines.

2. Undertake system wide voltage adequacy at peak operating conditions.

3. Perform system analyses to assess overall system losses, opportunities for mitigation investments, and impacts of those investments on reducing losses.

4. Align highest value loss mitigation opportunities with Total Resource Cost criteria, and perform TRC analyses as required using EnerSpectrum Group's TRC Calculator.

5. Report on findings and recommend courses of action.

Methodology

To undertake the scope of deliverables commissioned by Chapleau PUC as efficiently as possible, EnerSpectrum Group has developed a standardized methodology that leverages system data and knowledge of LDC employees without an inordinate time commitment. It then applied this information to the modeling and analyses methodology required to identify loss reduction opportunities. The following process was followed:

1. **Acquire data for the system model.** Establish and implement data acquisition and verification through an on-site presence of EnerSpectrum Group personnel working with Chapleau PUC technical/field staff.

2. **Build the system model.** Trace and capture in Dromey DESS software the supply points and physical route of the feeders from the data acquisition process in 1.

3. **Populate Transformer Data.** Populate the system model with characteristics of all transformers or loads on the feeders. Confirm modeled configuration with technical/field staff as required.

4. **Calibrate System Simulations.** Run the model at defined parameters and calibrate for feeder load and specific customer load conditions as required.

5. **Run System Simulations.** Run the calibrated model and assess system losses over OEB prescribed time frames (summer, winter, shoulder; on-peak, mid-peak, off-peak), and with various loss mitigation interventions.

6. **Conduct Total Resource Cost Analysis.** Undertake TRC calculations using EnerSpectrum Group's TRC Calculator to determine the full benefits of options for loss mitigation, and indicate where expenditures will be most prudently directed.

Chapleau PUC System Model Parameters

System modeling was performed by first establishing spatial reference from the Chapleau PUC supplied DWG file (see Appendix 1). Using existing system configuration on the drawing file, supplemental electrical model data was then acquired through field visits.

All resulting configuration, feeder size and phasing, and customer transformer size data were loaded onto DESS software as the base model.

Since customer transformer loading data was not available, a fixed percentage of each transformer's nameplate capacity was applied as a proxy load, and default DESS loads, load patterns, and characteristics were used. Resultant feeder loading from the model was then compared to average hourly load readings derived from manually recorded substation readings. Load scaling was then performed to fine tune modeled loads to measured loads in order to complete the calibration of the system model.

Diagnostics were performed against system capacity and ampacity limits, and a system voltage profile was assessed against CSA prescribed minimum levels at identified system peak load conditions.

Having established the base case, or model of the distribution systems as currently constituted , the calibrated model was then used to identify and analyze optimization scenarios across several parameters:

- Apply DESS phase balancing, switch and capacitor optimization routines
- Model optimum location for line regulation and rebalance phases accordingly
- Determine loss reductions for optimization runs over 24 hour periods for each seasonal time frame (winter, summer, shoulder)
- Tabulate and analyze results
- Recommend optimal configuration changes and/or capacitor additions

All modeled scenarios complied with The Ontario Energy Board (OEB)'s three season model to provide output data valid for TRC analysis:

- Summer - June, July, August, September
- Winter - December, January, February, March, and
- Shoulder - April, May, October, November

System Supply Adequacy Analysis

All system loading conditions are well within system component ampacity limits. All transformer loadings are within nameplate capacity ratings.

Voltage Adequacy

In the Base Case (current system) model, feeder F9 (4.16 kV) is configured to feed part of the north area across the Kebsquasheshung Lake and the out of town area in the south. During peak hours, the DESS model has shown that the voltage levels may be less than 92% of nominal on remote sections of the existing F9. Analysis indicates the section starting from Fox Lake Road and south may experience voltages as low as 87% of nominal feeder voltage on the red phase with a significant voltage imbalance in the three phases. In order to resolve the problem, switch optimization, phase balancing and line voltage regulation were identified as appropriate interventions. These interventions were then modeled as revisions to the base model. Several design iterations were then undertaken to determine the optimal configuration. The optimized system changes are identified in the description of Phase 1 which follows. These changes would adequately address voltage issues and restore all supply points to within 92 % of nominal voltage.

Having established the basis for voltage adequacy, subsequent interventions could then be modeled into scenarios for loss reduction.

Scenarios

Phase I - Base Case with Voltage Improvement

The Base Case (current system) is the existing 4.16kV and 25 kV systems, scale adjusted to represent an average day for each of the three TRC specified seasons. Following calibration against hourly metered system loads, voltage improvement scenarios were developed and the base case was adjusted accordingly.

Open Point Reconfiguration, Load Balancing, Voltage Regulation

Open point reconfiguration, load balancing, and voltage regulation were considered as a combined option for voltage improvement. The objective was to establish an appropriate basis from which to determine the impacts of loss mitigation scenarios.

Several iterations were necessary to determine the point of diminishing returns, whereby the incremental loss savings did not warrant the additional study time or configuration changes to achieve this.

The following tables illustrate the optimum combination of switch changes and load re-phasing.

Open Point Reconfiguration

Switch Number	Configuration Change
F81-x	Closed
F8-x	Open
S50(200)	Open
S22(140)	Closed

Table 1 – Open Point Configuration Changes

Load Balancing

Transformer Number	Configuration Change
262	Blue to red
256	Red to white
102	Blue to white
101	Blue to white
329-1	Red to white
334-1	Red to white
151	Red to white
229	Red to white
180	Red to white
280	Red to white
302	Red to blue
303	Red to blue
Single phase tap north of Richard and Adele (Include transformer 356, 357, 248, 247)	Red to blue
Single phase tap off transformer 353 (Include transformer 306, 307)	Red to blue
299	White to Red
Single phase tap off transformer 335 (Include transformer 305)	White to Red
273	Blue to Red

310	Bring the Blue phase line one more pole north and change 310 from blue to red

Table 2 – Load Balancing Configuration Changes

A three phase line voltage regulator bank was also modeled at node 463, on Highway No. 129.

The above configured changes are represented geographically in Appendix 2.

This revised Base Case establishes the system losses before any mitigation scenarios are deployed. Total system losses from the revised Base Case analysis was then the basis of comparison with alternative scenarios to determine where optimal gains could be made.

Total feeder losses were acquired and summed through system model runs over a 24 hour period. The peak power savings (kW) were calculated by taking the average of the hourly consumption during the on peak period. Results are detailed in Appendix 3 and summarized in the Table below.

	System Energy Losses			***Power Losses***
Season	Peak kWh	Mid-peak kWh	Off Peak kWh	On Peak kW
Winter	119,597	158,233	279,348	**243**
Summer	66,612	82,760	163,475	**125**
Shoulder	-	186,675	197,363	**-**

Table 3 – Reconfigured Open Point Reconfiguration, Load Balancing and Voltage Regulation – Phase I System Losses

Capacitor Installation – Phase II

Capacitor installation was considered as an additional option for loss reduction. Key for identifying additional loss mitigation opportunities was to reduce the reactive load on the system, thereby improving overall system power factor.

After applying the DESS capacitor optimization routine, two 225 kVAr capacitor banks were identified to be installed on the system.

The following table illustrates the location of these capacitor banks to be installed.

Capacitor Installation

Capacitor Bank Number	Feeder	Location
1	F8	At Node 342(Junction Point). In Richardson St. and Gold Course Road
2	F9	On the same pole as Node 225 (junction Point). On Elm and Elgin St.

Table 4 – Capacitor Installations

The above configured changes are represented geographically in the attached Appendix 2.

The system model runs with the two capacitor banks resulted in reduced losses as tabled below and detailed in Appendix 3:

	System Energy Losses			***Power Losses***
Season	Peak kWh	Mid-peak kWh	Off Peak kWh	On Peak kW
Winter	114380	152052	267325	**235**
Summer	64365	79214	159123	**119**
Shoulder	-	179482	189891	-

Table 5 – Two 3x75 kVAr capacitor banks – Phase ll System Losses

System Loss Differential

The total energy loss savings for each time period forms the foundation for TRC analysis, and the difference in the losses between the Phase I optimization scenario (Table 3) and the Phase II optimization scenario (Table 5) provides the incremental loss savings resulting from the capacitor installations. Loss savings for representative average days for each seasonal period are tabled below and detailed in Appendix 3:

	System Loss Savings			***Power Loss Savings***
Season	Peak kWh	Mid-peak kWh	Off Peak kWh	On Peak kW
Winter	5,217	6,181	12,023	**9**
Summer	2,247	3,547	4,316	**4**
Shoulder	-	7,193	7,472	-

Table 6 - Loss Savings for Optimized Chapleau PUC System

Estimated Overall Losses as a Percentage of Load

Average system measured losses as a percentage of total load are shown below:

Losses - Percentage of Total Load

Season Average	Phase I	Phase II
Winter	5.72%	5.53%
Summer	5.21%	4.99%
Shoulder	5.03%	4.84%
Overall Average	5.32%	5.12%

Table 7 – System Losses to Total Load

Contingency Supply

In the optimized system, there is a concern about whether the load on F2 can be transferred to F9 upon F2 supply interruption. The reason for this concern is that F2 currently crosses Kebsquasheshing Lake to serve loads in the north of town. The submarine cable represents an outage risk with few restoration options.

If an emergency situation should arise, it would be possible to transfer loads on F2 to F9. Analysis showed the resulting marginal voltage problem at the south end of F9 would be rectified through installation of the new line voltage regulator.

Another solution to the situation is to reconfigure the F81-X feeder to carry the load of F2. This could be done by building a connection from transformer 101 to switch S50(200), thereby permitting a connection to the F2 loads. Under this option, there would be no voltage concern during peak or other periods.

Supplemental Configuration Changes

Chapleau PUC staff have also expressed their interest in supplying existing 25 kV load on F5 to 4.16 kV, thereby off-loading current Hydro One 25kV supply feeder. With this incremental load added to the 4.16kV system, utilizing available F8 feeder capacity, and system reconfiguration as required, initial tests indicate adequate capacity and voltage levels. To prove the economic viability of system investment required, further study and data gathering need to be performed.

Phase I Costs

Cost estimates for work required to ensure acceptable voltage levels in phase I are as follows:

- Switch Changes: $450/switch pair operation
- Re-phasing: $450/ phase change
- 3 x 50 kVA phase line voltage regulator: $25,400

These costs are not attributable to reducing system losses and are therefore excluded from subsequent TRC analysis

TRC Analysis

TRC analysis was performed using EnerSpectrum Group's Total Resource Cost Calculator, which is an Excel-based tool for performing TRC calculations in accordance with the OEB's Total Resource Cost Guide.

A 30-year assessment period was selected for the TRC analysis, with the present year as 2007. As such, all capital expenditures were assumed to occur in 2007 with loss reduction savings starting in 2008.

TRC analyses was performed for the phase II scenario outlined above. Costing assumptions applied for capacitor bank installations are as follows:

- Capacitor Installations: $5000/installed 225 kVAr, 3 phase cap. Bank

The resulting TRC net present value analysis and supporting avoided cost tables associated with the assessed system changes are attached as Appendix 4.

The results of the TRC analysis for phase II are summarized in the following table. Chapleau PUC's weighted average cost of capital assumed in the calculations below was 7.25%, consistent with their most recent rate approval.

	TRC Results ($)
Total TRC Benefits	$ 59,362
Total TRC Costs	$ 10,000
Net TRC	**$ 49,362**

Table 8 – Phase II TRC Results

System Data Quality

Limited risk continues to reside within a number of assumptions that were taken to complete the DESS model, populate it with data, and then undertake the system analyses. EnerSpectrum Group believes that it is important that Chapleau PUC consider the risks, the proposed mitigation, and the likely residual risk in tabular form. The overall objective of mitigating the risks identified is to improve the accuracy of the analysis and confirm optimal operating configuration. In order to minimize residual risk, mitigation efforts should be considered in sequence as they appear from top to bottom in the following table:

Risk	Proposed Mitigation	Residual Risk
1) A lack of individual customer transformer loading data. The process of creating assumed customer transformer loading is robust when calibrating against interval metered supply point data. However, variations in individual load magnitudes, patterns, characteristics, etc. cannot be totally accurate.	Comprehensive conversion of customer load data from primary data source (eg., customer system, smart meter data, etc.) into the DESS model.	Minimal residual risk if customer load data can be synchronized with feeder loading data.
2) Overall system loading currently calibrates at metered supply points). Inaccuracies exist where supply points are not one to one with preferred calibration points (ie., feeders)	Install and monitor feeder metering (permanent and temporary) on key feeders (eg., heavily loaded compared to other feeders, non homogeneous customer loads, etc.). Recalibrate model based on feeder specific data.	Residual risk inversely proportional to the number of feeders metered.
3) DESS model inconsistencies with revisions/additions to actual field operating configuration	Establish a process for regular system model updates, using most current DESS model as the baseline and redlining changes accordingly.	Residual risk inversely proportional to the relative accuracy of the DESS model as compared to actual configuration.
4) Opportunities for other connectivity based analyses (outage management, work management, on line system queries, etc.) not exploited.	Initiate design and implementation of a GIS backbone system.	Residual risk is a function of the degree of commitment Chapleau PUC is prepared to make toward implementing GIS.

Table 9 – Risk Mitigation

Conclusions

Reconfiguring the normal operating configuration with the recommended switch changes, phase balancing and voltage regulation will improve year round voltage to within acceptable levels as per CSA standards.

The loss analysis was based on an average representative day for each period, in which many days will have loads and loss savings below this representative value, while many days will be above the representative value. Since losses and

consequently loss savings increase with the square of the load, this is a conservative approach which errs on the lower loss savings side.

Several risk mitigation efforts identified could potentially improve the accuracy of the study results and expose other opportunities for loss reduction. Further efforts in these areas would, for example, identify:

- √ The most cost effective method for tying customer loads to the system, thereby improving accuracy of feeder by feeder loading analysis.
- √ The most beneficial and cost effective procurement and placement of metering equipment, driving improvements in calibration accuracy.
- √ A more comprehensive analysis of the Chapleau PUC system including 4.16 kV and 25 kV supply.
- √ A process for routinely refreshing both configuration data and analyses.
- √ Options for consideration in pursuing a GIS backbone for Chapleau PUC.

Since capacitor installations introduce an active supply of kVAr's into the system, care must be taken to ensure the analysis accuracy. It would therefore be prudent to further refine calibration and analysis of the individual feeders identified for proposed capacitor installation(s).

Installed safety features and training for installation of capacitor banks on distribution systems is available through capacitor manufacturers/suppliers and with engineering support from EnerSpectrum Group.

Opportunities also exist to seek out and encourage large commercial customers with poor power factors to install capacitors at their supply substations where feasible. The benefit to the customer would be realized as a reduction to their monthly power bill, resulting from the reduction of power factor penalties. Both the customer and Chapleau PUC benefit from the resulting system kVAr injection and improvement to power factor and losses.

Recommendations

EnerSpectrum Group recommends the following:

- Address voltage adequacy issues at the peak period through the proposed open point reconfiguration, phase rebalancing and new line voltage regulator interventions.

- Consider using TRC analysis of proposed Phase II capacitor installations performed by EnerSpectrum Group in order to meet year end OEB reporting requirements.

- With assistance from EnerSpectrum Group, Chapleau PUC.pursue risk mitigation measures identified in the Risk/Mitigation/Residual Risk table to confirm the results of this study and to improve the accuracy and reliability of future studies.

- To maintain a viable loss profile, and accurate system models for planning and operational purposes, it is recommended that the systems be evaluated on 3-5 year routine.

Appendix 1 – System Configuration

Appendix 2 – Reconfigured System

Appendix 3 – Loss Summaries

Appendix 4 – TRC Analysis

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

Balance Sheet

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672
		-	-

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006	2006	Bridge Year	Test Year	Forecast
	Historical Board Approved	Historical Actual	2007	2008	2009
Revenue					
Distribution Revenue	$ 605,891	$ 567,925	$ 592,434	$ 680,023	$ 723,158
SSS Admin. and Retailer Charges	$ -	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,681	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	0	$ -	$ -	$ 24,631	$ 36,947
Revenue	$ 648,572	$ 611,964	$ 646,473	$ 749,633	$ 798,640
Operations and Maintenance	$ 263,311	$ 262,647	$ 296,913	$ 302,585	$ 308,637
Billing & Collecting	$ 65,879	$ 63,918	$ 66,539	$ 64,112	$ 66,035
Depreciation	$ 37,890	$ 37,370	$ 36,273	$ 36,563	$ 42,977
Administrative and General Expenses					
Community Relations	$ 2,607	$ 1,707	$ 1,063	$ 1,200	$ 1,200
Executive Salaries and Expense	$ 59,881	$ 59,331	$ 62,672	$ 64,552	$ 66,489
Office Supplies and Expense	$ 22,176	$ 19,432	$ 21,661	$ 22,248	$ 22,915
Outside Services Employed	$ 38,352	$ 47,795	$ 109,238	$ 60,820	$ 60,000
Property Insurance	$ 13,601	$ 12,119	$ 13,000	$ 13,500	$ 18,000
Regulatory Expenses	$ 5,734	$ 4,584	$ 5,769	$ 6,000	$ 12,000
Misc. General Expenses	$ 6,546	$ 10,612	$ 15,000	$ 12,000	$ 12,000
Bank Charges	$ 8,247	$ 8,941	$ 9,883	$ 9,200	$ 10,000
Low Voltage Charges (8 Moths Only)	$ -	$ -	$ -	$ 24,631	$ 36,947
Total Expenses	$ 524,224	$ 528,456	$ 638,011	$ 617,411	$ 657,200
Income (Loss)	$ 124,348	$ 83,508	$ 8,462	$ 132,222	$ 141,440
Interest Payable to Township of Chapleau	$ 48,454	$ -	$ -	$ 87,328	92207
Net Income (Loss)	$ 75,894	$ 83,508	$ 8,462	$ 44,894	$ 49,233

Cash Flow Forecast 2008 to 2012	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437
Net Income (Loss)	$ 8,462	$ 44,894	$ 49,000	$ 45,000	$ 45,000	$ 45,000
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (28,935)	$ (101,023)	$ (101,023)	$ (101,023)	$ (33,674)
Change in Accounts Reaceivable	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 977,637	$ 966,298	$ 525,684	$ 472,782	$ 461,437	$ 515,654

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Revenue Deficiency (Current Base Rates to Continue)

Revenue	Historical Actual 2006	(Forecast - Current Rates) Bridge Year 2007	Test Year 2008	2009
Distribution Revenue	$ 558,385	$ 592,434	$ 619,408	$ 619,631
SSS Admin. and Retailer Charges	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,657	$ 52,304	$ 43,244	$ 36,800
Low Voltage Revenue (8 Moths Only)	$ -	$ -	$ 24,631	$ 36,947
	$ 602,424	$ 646,473	$ 689,019	$ 695,113
Expenses				
Operations and Maintenance	$ 262,647	$ 296,913	$ 302,585	311,663
Administrative and General Expenses	$ 164,521	$ 238,286	$ 214,151	239,551
Billing & Collecting	$ 63,918	$ 66,539	$ 64,112	66,035
Depreciation	$ 37,370	$ 36,273	$ 36,563	42,977
Profit (Loss)	$ 73,968	$ 8,462	$ 71,607	$ 34,887
Interest Payable to Township of Chapleau	$ -	$ -	$ 87,328	92207
Profit (Loss)	$ 73,968	$ 8,462	$ (15,721)	$ (57,320)

Cash Flow Forecast 2008 to 2012

	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 824,729	$ 977,637	$ 905,683	$ 358,749	$ 198,847	$ 80,502
Net Income (Loss)	$ 8,462	$ (15,721)	$ (57,320)	$ (62,000)	$ (62,000)	$ (62,000)
Adjustments For Cash Flow						
Depreciation	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ (9,402)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ 114,075	$ (28,935)	$ (101,023)	$ (101,023)	$ (101,023)	$ (33,674)
Change in Accounts Reaceivable & other.	$ 3,500	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 977,637	$ 905,683	$ 358,749	$ 198,847	$ 80,502	$ 27,719

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

CUSTOMER CLASS IMPACT

	2008 TEST YEAR DATA				2008 Proposed Rates ($)								
					Volumetric Rate per kWh/kW							Fixed Service Charge	
	Number of Customers (Connections)	kWh	kW	Volumetric Rate Type	Base Rates (From Exhib. 8(b))	LV/ Wheeling (From Exhib. 5(a))	WMS & Rural per kWh (From Exhib. 5(b))	Trans. Rates CN & NW (From Exhib. 5(b))	Reg. Assets (From Exhib. 5(b))	Total Volumetric Rates kWh	Total Volumetric Rates kW	Base Rates	Total Revenue $
RESIDENTIAL													
Regular	1,177	14,611,894		kWh	0.0108	0.0013	0.0051	0.0062	(0.0036)	**0.0199**		**21.82**	**598,982.37**
GENERAL SERVICE													
Less than 50 kW	166	5,492,773		kWh	0.0108	0.0013	0.0051	0.0057	(0.0036)	**0.0194**		**39.99**	**186,053.23**
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	kW	1.7646	0.4809	0.0051	2.2960	(1.3205)	**0.0051**	**3.2210**	**223.14**	**145,218.47**
Unmetered Scattered Load	6	6,991		kWh	0.0108	0.0013	0.0051	0.0057	(0.0036)	**0.0193**		**19.61**	**1,547.04**
Sentinel Lighting	24	23,871	66	kW	6.1196	0.4738	0.0051	1.7613	(1.2956)	**0.0051**	**7.0591**	**4.33**	**1,834.26**
Street Lighting	341	295,064	780	kW	4.4562	0.4956	0.0051	1.7443	(1.3551)	**0.0051**	**5.3409**	**1.47**	**11,685.16**
TOTALS	**1,728**	**28,200,840**	**21,925**		258,790	36,903	144,573	172,115	(101,023)	438,830	72,528	433,963	**945,320.52**

	2008 TEST YEAR DATA				2007 Currently Approved Rates ($)								
					Volumetric Rate per kWh/kW							Fixed Service Charge	
	Number of Customers (Connections)	kWh	kW	Volumetric Rate Type	Base Rate	LV/ Wheeling	WMS & Rural	Trans. Rates CN & NW	Reg. Assets	Total Volumetric Rates kWh	Total Volumetric Rates kW	Base Rates	Total Revenue $
RESIDENTIAL													
Regular	1,177	14,611,894		kWh	0.0100	0.0	0.0062	0.0099	0.0007	**0.0268**		**19.92**	**672,949**
GENERAL SERVICE													
Less than 50 kW	166	5,492,773		kWh	0.0085	0.0	0.0062	0.0090	(0.0001)	**0.0236**		**31.17**	**191,720**
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	kW	1.2099	0.0	0.0062	3.6186	(0.2732)	**0.0062**	**4.5553**	**152.82**	**169,872**
Unmetered Scattered Load	6	6,991		kWh	0.0085	0.0	0.0062	0.0090	(0.0001)	**0.0236**		**15.46**	**1,278**
Sentinel Lighting	24	23,871	66	kW	3.7484	0.0	0.0062	2.7987	3.0482	**0.0062**	**9.5953**	**2.65**	**1,544**
Street Lighting	341	295,064	780	kW	2.4286	0.0	0.0062	2.7628	0.0178	**0.0062**	**5.2092**	**0.80**	**9,166**
TOTALS	**1,728**	**28,200,840**	**21,925**		220,513	0.0000	174,845	272,773	4,135	571,546	100,719	374,264	**1,046,530**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

CUSTOMER CLASS IMPACT

	2008 Total Revenue $	2007Total Revenue $	Class Impact Variance $	Class Impact Variance %
RESIDENTIAL				
Regular	598,982.37	672,948.84	(73,966.47)	-10.99%
GENERAL SERVICE				
Less than 50 kW	186,053.23	191,720.07	(5,666.85)	-2.96%
Greater than 50 kW (to 3000 kW)	145,218.47	169,871.99	(24,653.51)	-14.51%
Unmetered Scattered Load	1,547.04	1,278.11	268.93	21.04%
Sentinel Lighting	1,834.26	1,544.49	289.77	18.76%
Street Lighting	11,685.16	9,166.17	2,518.99	27.48%
TOTALS	945,320.52	1,046,529.67	(101,209.15)	-9.67%

	2008 Test Year Total Revenue $	2007 Bridge Year Total Revenue$	Revenue Change $
Rate Base - Volumetric charge	258,790	220,513	38,278
Rate Base - Service charge	429,729	370,031	59,698
- Smart Meter Rate	4234	4234	-
Low Voltage Rate	36,903	0.00	36,903
Wholesale Market Rate and Rural Rate	144,573	174,845	(30,272)
Transmission Rates (Connection and Network)	172,115	272,773	(100,658)
Regulatory Assets	(101,023)	4,135	(105,158)
Total Revenue	945,321	1,046,530	(101,209)

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Assets and Depreciation

Assets 2006	**Opening Balance at Jan. 1, 2006**	**Actual Purchases to Dec. 31, 2006**	**Closing Balance at Dec. 31, 2006**
Land	$ 140.50	$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56	$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,110,648.07	$ 1,550.88	$ 1,112,198.95
Underground Conduit	$ 77,299.99	$ -	$ 77,299.99
Line Transformers	$ 339,040.90	$ 21,899.21	$ 360,940.11
Meters	$ 167,009.20	$ 842.40	$ 167,851.60
	$ 2,151,646.22	$ 24,292.49	**$ 2,175,938.71**

2006 Average of Opening and Closing Year Balance of Gross Assets	**$ 2,163,792.47**

Depreciation 2006				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (148,293.56)	4%	$ (12,369.00)	$ (160,662.56)
Poles Towers and Fixtures	$ (737,693.07)	4%	$ (14,948.88)	$ (752,641.95)
Underground conduit	$ (44,342.99)	4%	$ (1,318.00)	$ (45,660.99)
Line Transformers	$ (219,647.90)	4%	$ (5,214.21)	$ (224,862.11)
Meters	$ (79,430.20)	4%	$ (3,520.40)	$ (82,950.60)
	$ (1,229,407.72)		$ (37,370.49)	**$ (1,266,778.21)**

2006 Capital Expenditures

1 - 5 Poles $1,551 in-service in Sept. 2006 to replace old existing Poles.
2 - 8 Line Transformers $21,899 in-service throuout 2006 to replace old existing Line Transformers
3 - 3 GS and 5 Res. Meters $842 in service at various times during 2006 to replace old Meters.

2006 Average of Opening and Closing Year Balance for Depreciation	**$ (1,248,092.97)**
2006 Average of Opening and Closing Year Balance for Net Assets	**$ 915,699.50**
2006 Net Fixed Assets	**$ 909,160.50**
Materiality Threshold of 1%	**$ 9,091.61**

Assets 2007	**Opening Balance at Jan. 1, 2007**	**Actual Purchases to Jun. 30, 2007**	**Forecast Purchases to Dec. 31, 2007**	**Forecast to Dec. 31, 2007**
Land	$ 140.50	$ -	$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56	$ -	$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,112,198.95	$ -	$ 2,500.00	$ 1,114,698.95
Underground Conduit	$ 77,299.99	$ -	$ -	$ 77,299.99
Line Transformers	$ 360,940.11	$ 6,901.83	$ -	$ 367,841.94
Meters	$ 167,851.60	$ -	$ -	$ 167,851.60
	$ 2,175,938.71	**$ 6,901.83**	**$ 2,500.00**	**$ 2,185,340.54**

2007 Average of Opening and Closing Year Balance of Gross Assets	**$ 2,180,639.63**

Depreciation 2007				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (160,662.56)	4%	$ (11,873.80)	$ (172,536.36)
Poles Towers and Fixtures	$ (752,641.95)	4%	$ (14,432.28)	$ (767,074.23)
Underground conduit	$ (45,660.99)	4%	$ (1,265.56)	$ (46,926.55)
Line Transformers	$ (224,862.11)	4%	$ (5,305.08)	$ (230,167.19)
Meters	$ (82,950.60)	4%	$ (3,396.04)	$ (86,346.64)
	$ (1,266,778.21)		**$ (36,272.76)**	**$ (1,303,050.97)**

2007 Capital Expenditures

1 - 8 Poles $2,500 in-service in Sept/Oct. 2007 to replace old existing Poles.
2 - 2 Line Transformers & 1 Padmount transformer $6,902 in-service during 2076 to replace old existing Transformers.

2007 Average of Opening and Closing Year Balance of Depreciation	**$ (1,284,914.59)**
2007 Average of Opening and Closing Year Balance of Net Assets	**$ 895,725.03**
2007 Net Fixed Assets	**$ 882,289.57**
Materiality Threshold of 1%	**$ 8,822.90**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Assets 2008	**Opening Balance at Jan. 1, 2008**	**Budget Purchases to Dec. 31, 2008**	**Budget to Dec. 31, 2008**
Land	$ 140.50	$ -	$ 140.50
Distribution Station Equip. Below 50kV	$ 457,507.56	$ -	$ 457,507.56
Poles Towers and Fixtures	$ 1,114,698.95	$ 4,000.00	$ 1,118,698.95
Overhead Conductors and Devices	$ -	$ 23,500.00	$ 23,500.00
Underground conduit	$ 77,299.99	$ -	$ 77,299.99
Line Transformers	$ 367,841.94	$ 7,000.00	$ 374,841.94
Meters	$ 167,851.60	$ 29,361.30	$ 197,212.90
	$ 2,185,340.54	**$ 63,861.30**	**$ 2,249,201.84**
2008 Average of Opening and Closing Year Balance of Gross Assets			**$ 2,217,271.19**

Depreciation 2008				
Land	$ -		$ -	$ -
Distribution Station Equip. Below 50kV	$ (172,536.36)	4%	$ (11,398.85)	$ (183,935.17)
Poles Towers and Fixtures	$ (767,074.23)	4%	$ (13,984.99)	$ (781,059.18)
Overhead Conductors and Devices	$ -	4%	$ (470.00)	$ (469.96)
Underground conduit	$ (46,926.55)	4%	$ (1,214.94)	$ (48,141.45)
Line Transformers	$ (230,167.19)	4%	$ (5,646.99)	$ (235,814.14)
Meters	$ (86,346.64)	4%	$ (3,847.42)	$ (90,194.02)
	$ (1,303,050.97)		**$ (36,563.19)**	**$ (1,339,613.92)**

2008 Capital Expenditures

1 - 10 Poles $4,000 in-service during 2008 to replace old existing Poles.
2 - 3 Regulators $23,500 in-service during 2008 to help reduce line losses
3 - 3 Line Transformers $7,000 in-service during 2008 to replace old existing Line Transformers
4 - Start-up cost for Smart Meters $29,361 (Legal, Consulting, etc.) during 2008.

2008 Average of Opening and Closing Year Balance of Depreciation	**$ (1,321,332.45)**
2008 Average of Opening and Closing Year Balance of Net Assets	**$ 895,938.74**
2008 Net Fixed Assets	**$ 909,587.92**
Materiality Threshold of 1%	**$ 9,095.88**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

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Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Rate Base Calculation	**Board Approved 2006**		**Historical Actual 2006**		**Bridge Year 2007**		**Test Year 2008**	
Net Fixed Assets - at December 31		**$ 943,844**		**$ 909,161**		**$ 882,290**		**$ 909,588**
Materiality Level (1% of net assets)	**$ 9,438**		**$ 9,092**		**$ 8,823**		**$ 9,096**	
Working Capital Allowance								
Power Purchased			$ 1,721,671		$ 1,782,162		$ 1,751,917	
WMS charges			$ 154,628		$ 152,308		$ 153,468	
Network charges			$ 153,524		$ 147,202		$ 133,613	
Connection charges			$ 59,948		$ 51,081		$ 49,458	
Low Voltage charges			$ 13,195		$ 36,947		$ 36,947	
Power adjustment			$ -		$ -		$ -	
			$ 2,102,966		$ 2,169,700		$ 2,125,403	
Expenses - Net of Depreciation less Low Voltage Charges			$ 491,086		$ 601,738		$ 556,217	
Working Capital	$ 2,618,701		$ 2,594,052		$ 2,771,438		$ 2,681,620	
Working Capital Allowance @15%		**392,805.15**		**389,107.80**		**415,715.70**		**$ 402,243.00**
Rate Base		**$ 1,336,649**		**$ 1,298,268**		**$ 1,298,005**		**$ 1,311,831**
Fixed Assets for Energy Conservation (Smart Meters)								
Smart Meter purchases 2008							$ 29,361	
Smart Meter purchases 2009 to 2012							$ 505,156	
Service Revenue Requirement								
Rate Base	**$ 1,336,649**		**$ 1,298,268**		**$ 1,298,005**		**$ 1,311,831**	
Cost of Capital	**8.13%**		**8.13%**		**8.13%**		**8.13%**	
Return on Ratebase		$ 108,603		$ 105,549		$ 105,528		$ 106,652
Distribution Expenses		$ 524,223		$ 528,456		$ 638,011		$ 617,239
Revenue Requirement Before Income Taxes		**$ 632,826**		**$ 634,005**		**$ 743,539**		**$ 723,891**
Income Taxes - from PILS Model				$ -		$ -		$ -
Service Revenue Requirement		**$ 632,826**		**$ 634,005**		**$ 743,539**		**$ 723,891**

3 Variance Analysis for Rate Base

Board Approved vs Historical Actual — **Board Approved net fixed assets were ovestated to Historical Actual by $34,683 caused by an understatement in both Gross Assets and Accumulated Depreciation of $59,364 and $94,046 respectively. Net Impact to Board Approved Rate Base is $$38,381 (overstated). Net impact to Service Revenue Requirement is below materiality level.**

Historical Actual vs Bridge Year. — **Bridge Year is $10,131 higher than Historical Year due to Lower Capital Expenditures that reduced Net Assets by $27,851 and an increase in Working Capital Allowance of $37,982, this is mainly due to an increase in the Cost of Power of $95,979, an increase (full year) in Low Voltage charges of $23,493 and higher than expected Distribution Expenses (Outside Servises employed of $77,545 and Operations and Maintenanse of $37,353)**

Bridge Year vs Test Year. — **Test Year is higher than Bridge Year by $12,995 due to an increase in Capital Expenditures of $27,337and is a reduction in Working Capital Allowance of $14,343, this is manly due to a reduction in the Cost of Power of $47,990 and a reduction in Distribution Expenses of $48,560 (Redused spending in Outside Servises employed of $65,340 and increased spending in Operation and Maintanance of $6,400 and inflationary increases in other areas of $10,380)**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 2

Cost of Capital

Rate Base: (from above *Ratebase Calc.*)	**$ 1,311,831**		
Size of LDC (based on Rate Base)	**small**		
Debt Rate (based on Size)	**6.25%**		
Deemed Debt (based on Size)	**53.3%**		
Deemed Equity (based on Size)	**46.7%**		
Proposed Debt Rate	**7.25%**		
Utility's Proposed ROE	**9.00%**		
Cost of Capital	**8.07%**		
Revenue Requirement other than PILS		**$**	**723,891**
Distribution Expenses other than PILS and interest		$	617,239
		$	**106,652**
Calculated Interest			
Rate Base	**$ 1,311,831**		
Debt Component	**53.3%**		
Debt Rate reflected in Revenue Requirement	**7.25%**		50,692
Target Net Income (for PILs)		**$**	**55,959**
Service Revenue Requirement		**$**	**723,891**
Board Approved Charges			
Specific Service Charges	$ 17,728		
Late Payment Charges	$ 4,665		
Other Distribution Revenue	$ 1,735		
Other Income & Deductions	$ 20,852		
	$ 44,980	**$**	**44,980**
Base Revenue Requirement		**$**	**678,911**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528
EXHIBIT 3 (a)
CUSTOMER DATA

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Year	Month	Wholesale purchase kWh		Resident kWh	GS<50kW kWh	GS>50kW kWh	GS>50kW kW	USL kWh	Sentinel Lights kWh	Sentinel Lights kW	Street Lights kWh	Street Lights kW	Total KWh	Total KW
2005	Jan	4,114,085		2,075,699	720,780	919,963	2,335	603	1992	7	32798	75	3,751,835	2,417
2005	Feb	3,275,429		1,784,654	624,726	808,068	2,416	603	1917	7	26726	75	3,246,694	2,498
2005	Mar	3,236,656		1,533,173	567,873	736,474	2,321	603	1928	6	26024	70	2,866,075	2,397
2005	Apr	2,386,028		1,127,220	458,349	614,989	2,001	603	1881	6	21390	70	2,224,432	2,077
2005	May	2,131,198		937,262	400,057	573,698	1,839	603	1929	5	18716	60	1,932,265	1,903
2005	Jun	1,758,000		772,380	355,015	519,014	1,604	603	1933	5	15870	55	1,664,815	1,663
2005	Jul	1,681,638		723,513	365,980	503,146	1,553	603	1988	4	17469	55	1,612,699	1,612
2005	Aug	1,681,674		719,897	351,866	517,144	1,457	603	1874	5	20499	55	1,611,883	1,516
2005	Sept	1,779,924		787,517	343,299	558,804	1,452	603	1909	5	23460	60	1,715,592	1,516
2005	Oct	2,294,542		1,106,552	422,670	690,677	1,670	603	2498	6	28163	65	2,251,163	1,741
2005	Nov	3,029,797		1,467,052	532,427	815,577	2,061	603	1979	6	30705	70	2,848,343	2,137
2005	Dec	3,689,681		1,778,206	621,704	852,391	2,232	603	2003	6	33867	70	3,288,774	2,308
TOTALS		31,058,652		14,813,125	5,764,746	8,109,945	22,939	7236	23831	66	295687	780	29,014,570	23,785
2006	Jan	3,371,350		1,832,027	644,101	849,594	2,482	603	1922	7	31740	75	3,359,987	2,564
2006	Feb	3,384,486		1,631,657	582,176	809,941	2,297	603	1829	7	26726	75	3,052,932	2,379
2006	Mar	3,170,628		1,581,749	564,919	836,060	2,026	603	2123	6	26024	70	3,011,478	2,102
2006	Apr	2,363,723		1,172,907	425,432	589,581	1,952	603	1946	6	21390	70	2,211,859	2,028
2006	May	2,001,924		954,508	378,171	544,763	1,528	451	1907	5	18716	60	1,898,516	1,592
2006	Jun	1,697,230		768,369	338,149	493,188	1,310	451	1897	5	15870	55	1,617,924	1,369
2006	Jul	1,663,765		725,730	353,593	467,853	1,268	451	1900	4	17468	55	1,566,995	1,327
2006	Aug	1,600,280		735,225	344,233	451,826	1,231	601	1928	5	20499	55	1,554,312	1,290
2006	Sept	1,818,043		857,734	337,367	511,801	1,336	601	1977	4.5	23460	60	1,732,940	1,400
2006	Oct	2,466,157		1,165,113	429,726	666,461	1,692	601	1965	6	28037	65	2,291,903	1,763
2006	Nov	2,765,361		1,402,127	505,312	738,317	1,892	601	2019	6	30705	70	2,679,081	1,968
2006	Dec	3,266,327		1,631,376	554,463	763,778	1,882	601	1984	6	33868	70	2,986,070	1,958
TOTALS		29,569,274		14,458,522	5,457,642	7,723,163	20,894	6770	23397	66	294503	780	27,963,997	21,740
2007	Jan	3,618,490 A	A	1,876,237	654,759	828,146	1,906	601	2108	7	32798	75	3,394,649	1,988
2007	Feb	3,629,416 A	A	1,775,994	635,459	803,081	2,069	601	2046	7	26726	75	3,243,907	2,151
2007	Mar	3,152,119 A	A	1,663,322	579,362	789,176	2,041	601	2148	6	26024	70	3,060,633	2,117
2007	Apr	2,500,401 A	A	1,219,276	424,026	572,381	1,879	601	1960	6	21390	70	2,239,634	1,955
2007	May	1,871,049 A	A	910,041	369,435	486,521	1,693	601	2155	5	18716	60	1,787,469	1,757
2007	Jun	1,676,726 A	E	770375	346582	506101	1,457	601	1915	5	15870	55	1,641,444	1516
2007	Jul	1,672,702	E	724622	359787	485500	1,411	601	1944	4	17469	55	1,589,921	1470
2007	Aug	1,640,977	E	727561	348050	484485	1,344	601	1901	5	20499	55	1,583,097	1403
2007	Sept	1,798,984	E	822626	340333	535303	1,394	601	1943	5	23460	60	1,724,265	1458
2007	Oct	2,380,350	E	1135833	426198	678569	1,681	601	2232	6	28100	65	2,271,532	1752
2007	Nov	2,897,579	E	1434590	518870	776947	1,977	601	1999	6	30705	70	2,763,711	2053
2007	Dec	3,478,004	E	1704791	588084	808085	2,057	601	1994	6	33868	70	3,137,421	2133
	Adjustments				-47280	47280	269						0	269
		30,316,796		14,765,266	5,543,663	7,801,574	21,175	7,212	24,344	66	295,624	780	28,437,682	22,021
		2008 estimates are the average of 2005/6/7											28,437,682	
2008	Jan	3,494,920	E	1,854,132	649,430	838,870	2,194	602	2,015	7	32,269	75	3377318	2,276
2008	Feb	3,506,951	E	1,703,826	608,818	806,511	2,183	602	1,938	7	26,726	75	3148420	2,265
2008	Mar	3,161,374	E	1,622,536	572,141	812,618	2,034	602	2,136	6	26,024	70	3036056	2,110
2008	Apr	2,432,062	E	1,196,092	424,729	580,981	1,916	602	1,953	6	21,390	70	2225747	1,992
2008	May	1,936,487	E	932,275	373,803	515,642	1,610	526	2,031	5	18,716	60	1842993	1,675
2008	Jun	1,686,978	E	769,372	342,366	499,645	1,383	526	1,906	5	15,870	55	1629684	1,443
2008	Jul	1,668,233	E	725,176	356,690	476,676	1,339	526	1,922	4	17,468	55	1578458	1,398
2008	Aug	1,620,629	E	731,393	346,141	468,156	1,287	601	1,915	5	20,499	55	1568704	1,347
2008	Sept	1,808,513	E	840,180	338,850	523,552	1,365	601	1,960	5	23,460	60	1728603	1,429
2008	Oct	2,423,253	E	1,150,473	427,962	672,515	1,687	601	2,098	6	28,069	65	2281718	1,758
2008	Nov	2,831,470	E	1,418,358	512,091	757,632	1,934	601	2,009	6	30,705	70	2721396	2,010
2008	Dec	3,372,166	E	1,668,084	571,273	785,931	1,970	601	1,989	6	33,868	70	3061746	2,046
	Adjustments				-47280	47280	269							269
		29,943,035		14,611,894	5,477,013	7,786,008	21,169	6,991	23,871	66	295,064	780	28,200,840	22,015

Chapleau Public Utilities Corporation

License Number: ED-2002-0528
EXHIBIT 3 (a)
CUSTOMER DATA

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Year	Wholesale Purchases	Customer Data by Class															Total		
		Residential		GS <50kW		GS >50kW			USL		Sentinel Lights			Street Lights					
	kWh	# of Cust	kWh	# of Cust	kWh	# of Cust	kWh	kW	# of Cust	kWh	# of Cust	kWh	kW	# of Cust	kWh	kW	# of Cust	kWh	kW
2002	34,764,471	1,175	16,842,271	175	6,062,613	15	10,415,498	22,852	6	7,212	30	33,333	98	341	220,459	650	1,742	33,581,386	23,600
2003	33,611,224	1,164	16,533,903	162	6,027,452	14	9,668,139	25,121	6	7,212	27	27,506	76	341	219,856	771	1,714	32,484,068	25,968
2004	32,654,946	1,166	15,978,327	163	5,952,232	13	8,798,182	24,094	6	7,212	24	23,670	66	341	221,064	789	1,713	30,980,687	24,949
2005	31,058,652	1,171	14,813,125	167	5,764,746	13	8,109,945	22,939	6	7,236	24	23,831	66	341	295,687	780	1,722	29,014,570	23,785
2006	29,569,274	1,190	14,458,522	165	5,457,642	14	7,723,163	20,894	6	6,770	24	23,397	66	341	294,503	780	1,740	27,963,997	21,740
2007	30,316,796	1,164	14,765,266	166	5,543,663	14	7,801,574	21,175	6	7,212	24	24,344	66	341	295,624	780	1,715	28,437,682	22,021
2008	29,943,035	1,177	14,611,894	166	5,477,013	14	7,786,008	21,169	6	6,991	24	23,871	66	341	295,064	780	1,728	28,200,840	22,015

Loss Factor Calculation

Year	Wholesale Purchases	Distribution	Loss Factor
	kWh	kWh	%
2002	34,764,471	33,581,386	1.0352
2003	33,611,224	32,484,068	1.0347
2004	32,654,946	30,980,687	1.0540
2005	31,058,652	29,014,570	1.0705
2006	29,569,274	27,963,997	1.0574
2007	30,316,796	28,437,682	1.0661
2008	29,943,035	28,200,840	1.0618
Average Loss Factor 2003 to 2007 (5 Years)			**1.0565**

Notes To this Page

1 2007 Forecast of Data is actual data to May, and from June to December is forecasted to be the average consumption for the previous two years (2005/2006).

2 2008 Forecast of Data is the average consumption level for 2006 and 2007 for all classes.

3 Data supplied from 2002 to 2006 is to show the reduced consumption levels by 16.7% (and therefore reduced distribution revenue) for all classes caused mainly throughrecent economic conditions and reduced population levels.

4 The increase in loss factors is due the age of Chapleau's infrastructure in certain parts of the town. A study has been undertaken to address this. Chapleau PUC will invest $23,500 in the replasement of conductors during 2007 in an efford to reduce line losses.

5 Customer transfers: 1 from GS <50kW to GS >50kW and 1 from GS >50kW to GS <50kW - Data adjusted for 2007 and 2008.

Average Consumptions by customer

Year	Purchases	Residential		Ave. kWh		GS <50kW		Ave. kWh	GS >50kW			Ave kWh	Ave. kW
	kWh	# of Cust	kWh	Consump		# of Cust	kWh	Consump	# of Cust	kWh	kW	Consump	Consump
2002	34,764,471	1,175	16,842,271	14,334		175	6,062,613	34,644	15	10,415,498	22,852	694,367	1,523.5
2003	33,611,224	1,164	16,533,903	14,204		162	6,027,452	37,206	14	9,668,139	25,121	690,581	1,794.4
2004	32,654,946	1,166	15,978,327	13,704		163	5,952,232	36,517	15	8,798,182	24,094	586,545	1,606.3
2005	31,058,652	1,171	14,813,125	12,650		167	5,764,746	34,519	13	8,109,945	22,939	623,842	1,764.5
2006	29,569,274	1,190	14,458,522	12,150		165	5,457,642	33,077	14	7,723,163	20,894	551,655	1,492.4
2007	30,316,796	1,164	14,765,266	12,685		166	5,543,663	33,396	14	7,801,574	21,175	557,255	1,512.5
2008	29,943,035	1,177	14,611,894	12,415		166	5,477,013	32,994	14	7,786,008	21,169	556,143	1,512.1

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (b)

CONSUMPTION DATA

	Number of Customers (Connections)			Demand Data - kWh			Demand Data - kW			2007 Approved Rates		
	2006	2007	2008	2006	2007	2008	2006	2007	2008	Distribution Rate kWh	Distribution Rate kW	Mthly Service Chrg (Per Cust. or Connection)
	#	#	#	kWh	kWh	kWh	kW	kW	kW	$	$	$
RESIDENTIAL												
Regular	1,190	1,164	1,177	14,458,522	14,765,266	14,611,894	0	0	0	0.0100		19.92
GENERAL SERVICE												
Less than 50 kW	165	166	166	5,457,642	5,543,663	5,477,013	0	0	0	0.0085		31.17
Greater than 50 kW (to 3000 kW)	14	14	14	7,723,163	7,801,574	7,786,008	20,894	21,175	21,169		1.2099	152.82
Unmetered Scattered Load	6	6	6	6,770	7,212	6,991	0	0	0	0.0085		15.46
Sentinel Lighting	24	24	24	23,397	24,344	23,871	66	66	66		3.7484	2.65
Street Lighting	341	341	341	294,503	295,624	295,064	780	780	780		2.4286	0.80
TOTALS	1,740	1,715	1,728	27,963,997	28,437,682	28,200,840	21,740	22,021	22,015			

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (b)

TRANSFORMER CREDIT

	2006			2007			2008		
	kW	$/kW	$	kW	$/kW	$	kW	$/kW	$
RESIDENTIAL									
Regular			0.00			0.00			0.00
GENERAL SERVICE									
Less than 50 kW			0.00			0.00			0.00
Greater than 50 kW (to 3000 kW)	16,462	0.60	9,877.06	15,572	0.60	9,343.00	16,017	0.60	9,610.03
Unmetered Scattered Load			0.00			0.00			0.00
Sentinel Lighting	0	0.60	0.00		0.60	0.00	0	0.60	0.00
Street Lighting	0	0.60	0.00		0.60	0.00	0	0.60	0.00
TOTALS	16,462		9,877.06	15,572		9,343.00	16,017		**9,610.03**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (c)

2006 Board Approved (DISTRIBUTION REVENUE)

2006 Data by Class (From Cust. Data Sheet)	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2006	
					Fixed	Variable
Residential Class		16,417,968	1,166	$438,740	$ 19.74	$ 0.0099
General Service Less than 50 kW		5,887,927	163	$109,879	$ 30.89	$ 0.0084
General Service 50 to 4,999 kW	22,409	8,934,168	13	$50,489	$ 151.43	$ 1.1989
Unmetered Scattered Load		7,212	6	$1,164	$ 15.32	$ 0.0084
Sentinel Lighting	71	24,929	24	$1,021	$ 2.63	$ 3.7142
Street Lighting	737	220,460	341	$5,006	$ 0.79	$ 2.4065
TOTALS	**23,217**	**31,492,664**	**1,713**	**$605,891**		

Actual Distribution Revenue as per 2006 Financial Statements **$ 567,925**

2006 Actual (DISTRIBUTION REVENUE)

2006 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2006	
					Fixed	Variable
Residential Class		14,458,522	1,190	$425,027	$ 19.74	$ 0.0099
General Service Less than 50 kW		5,457,642	165	$107,006	$ 30.89	$ 0.0084
General Service 50 to 4,999 kW	20,894	7,723,163	14	$50,490	$ 151.43	$ 1.1989
Unmetered Scattered Load		6,770	6	$1,160	$ 15.32	$ 0.0084
Sentinel Lighting	66	23,397	24	$1,003	$ 2.63	$ 3.7142
Street Lighting	780	294,503	341	$5,110	$ 0.79	$ 2.4065
TOTALS	**21,740**	**27,963,997**	**1,740**	**$589,795**		

Less Revenue Jan to April @ old Rates. **$ 21,870**
Actual Distribution Revenue as per Financial Statements **$ 567,925**

2007 Bridge Year (DISTRIBUTION REVENUE)

2007 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	APPROVED RATES EFFECTIVE MAY 1, 2007	
					Fixed	Variable
Residential Class		14,765,266	1,164	$425,895	$ 19.92	$ 0.0100
General Service Less than 50 kW		5,543,663	166	$109,212	$ 31.17	$ 0.0085
General Service 50 to 4,999 kW	21,175	7,801,574	14	$51,293	$ 152.82	$ 1.2099
Unmetered Scattered Load		7,212	6	$1,174	$ 15.46	$ 0.0085
Sentinel Lighting	66	24,344	24	$1,011	$ 2.65	$ 3.7484
Street Lighting	780	295,624	341	$5,168	$ 0.80	$ 2.4286
TOTALS	**22,021**	**28,437,683**	**1,715**	**$593,753**		

Less Revenue Jan to April @ old Rates = 1/3 of ($593,753 - $589,795) = $3,958/3 = $1,319 **$ 1,319**
$592,434

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

2008 Test Year (DISTRIBUTION REVENUE)

2008 Data by Class (From Exhibit 3(a))	kW	kWh	Number of Customers (Connections)	Distribution Revenues	PROPOSED RATES 2008	
					Fixed	Variable
Residential Class		14,611,894	1,177	$484,473	$ 21.68	$ 0.0122
General Service Less than 50 kW		5,477,013	166	$145,115	$ 39.58	$ 0.0121
General Service 50 to 4,999 kW	21,169	7,786,008	14	$84,675	$ 222.22	$ 2.2364
Unmetered Scattered Load		6,991	6	$1,362	$ 17.84	$ 0.0111
Sentinel Lighting	66	23,871	24	$1,198	$ 3.06	$ 4.7963
Street Lighting	780	295,064	341	$6,335	$ 0.92	$ 3.2948
TOTALS	**22,015**	**28,200,841**	**1,728**	**$723,158**		

Less Revenue Jan to April @ old Rates = 1/3 of ($723,158 - $593,753) = $129,405/3 = $43,135 **$ 43,135**
$680,023

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 3 (c)

SPECIFIC SERVICE CHARGES

Description	Standard Amount (Rate) $	2006 Revenue	2007 Revenue
Returned cheque charge (plus bank charges)	15.00	$ -	$ 330.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	30.00	$ 1,132.50	$ 5,062.50
Disconnect/Reconnect at meter - during regular hours	65.00	$ 1,200.00	$ 1,675.00
Specific Charge for Access to the Power Poles $/pole/year	22.35	$ 1,471.87	$ 4,498.54
TOTAL REVENUE - SPECIFIC SERVICE CHARGES		$ 3,804.37	$11,566.04

OTHER REVENUE SOURCES	2006	2007	2008
Interest Earned	$ 12,395.10	$16,087.12	$ 15,575.00
Meter Exit Rebate from Hydro One	$ 14,126.90	$17,100.00	$ -
Sale of Material	$ 7,286.84	$ 2,206.70	$ 4,747.00
Miscellaneous	$ 360.44	$ 698.77	$ 530.00
TOTAL OTHER REVENUE	**$ 34,169.28**	**$36,092.59**	**$ 20,852.00**

Description	Standard Amount (Rate) $	2005 Volume	2006 Volume	2007 Volume	2008 Test Year Volume (3 yr. avg.)	Calc'd. Amt. Std. Formula $
Arrears certificate	15.00	44	35	0	0	**0.00**
Credit reference/credit check (plus credit agency costs)	15.00	2	12	10	8	**120.00**
Returned cheque charge (plus bank charges)	15.00	34	28	22	28	**420.00**
Charge to certify cheque	15.00	0	0	0	0	**0.00**
Legal letter charge	15.00	0	0	0	0	**0.00**
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	30.00	274	286	262	274	**8,220.00**
Special meter reads	30.00	0	0	0	0	**0.00**
Collection of account charge - no disconnection	30.00	0	0	0	0	**0.00**
Collection of account charge - no disconnection - after regular hours	165.00				0	**0.00**
Disconnect/Reconnect at meter - during regular hours	65.00	12	60	50	41	**2,643.00**
Install/Remove load control device - during regular hours	65.00				0	**0.00**
Meter dispute charge plus Measurement Canada fees (if meter found correct)	30.00	0	0	0	0	**0.00**
Specific Charge for Access to the Power Poles $/pole/year	22.35	283	283	283	283	**6,325.05**
TOTAL REVENUE - SPECIFIC SERVICE CHARGES						**17,728.05**

DISTRIBUTION, MISCELLANEOUS AND OTHER REVENUE

	Board Approved 2006	Historical Yr 2006	Bridge Yr 2007 (est)	Test Year 2008 (est)
Distribution Revenue	**$ 605,891**	**$ 567,925**	**$592,434**	**$680,023**
Late Payment Charges	**$ 5,900**	**$ 4,683.71**	**$ 4,645.83**	**$ 4,664.77**
Specific Service Charges	**$ 16,737**	**$ 3,804.37**	**$11,566.04**	**$ 17,728.05**
Other Revenue Sources	**$ 14,822**	**$ 34,169.28**	**$36,092.59**	**$ 20,852.00**
Total Miscellaneous Revenue	**$ 37,459.00**	**$ 42,657.36**	**$52,304.46**	**$ 43,244.82**
Other Distribution Revenue - Retailer Charges	**$ 5,222**	**$ 1,381.60**	**$ 1,735.00**	**$ 1,735.00**
TOTAL REVENUE	**$ 648,572**	**$ 611,964**	**$ 646,474**	**$ 725,003**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 4

OPERATING COSTS

	Oparating and Maintenance	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
1	**Operations and Maintenance**	$ 263,311	$ 274,181	$ 296,913	$ 302,585
2	**Billing & Collecting**	$ 65,879	$ 60,018	$ 66,539	$ 64,112
3	**Depreciation**	$ 37,890	$ 37,370	$ 36,273	$ 36,563
	Administrative and General Expenses				
4	**Community Relations**	$ 2,607	$ 1,707	$ 1,063	$ 1,200
5	**Executive Salaries and Expense**	$ 59,881	$ 59,331	$ 62,672	$ 64,552
6	**Office Supplies and Expense**	$ 22,176	$ 19,432	$ 21,661	$ 22,248
7	**Outside Services Employed**	$ 38,352	$ 47,795	$ 109,238	$ 60,820
8	**Property Insurance**	$ 13,601	$ 12,119	$ 13,000	$ 13,500
9	**Regulatory Expenses**	$ 5,734	$ 4,584	$ 5,769	$ 6,000
10	**Misc. General Expenses**	$ 6,546	$ 10,612	$ 15,000	$ 12,000
11	**Bank Charges**	$ 8,247	$ 8,941	$ 9,883	$ 9,200
12	**Low Voltage Charges (8 Moths Only)**	$ -	$ -	$ -	$ 24,631
	TOTAL OPERATING COSTS	$ 524,224	$ 536,090	$ 638,011	$ 617,411
	Variance Analysis Threshold 1%		$ 5,361	$ 6,380	$ 6,174

Variance Analysis

Board Approved - Historical Year. Historical Year Billing and Collections lower due mainly to lower write offs/Bad Debt Expense.
Historical Year Office Supplies and Expense lower due to the timing of perchasing supplies.
Historical Year - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000
Historical Year Misc. Gen. Expenses higher due to additional travel expenses for Board members and Management to attend industry meetings.

Historical Year - Bridge Year Bridge Year Billing and Collections higher due mainly to write offs/Bad Debt Expense.
Bridge Year - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000
Bridge Year Misc. General Expense higher due to higher travel expenses required for Smart Meter Program.

Operations and Maintenance	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Dist. Station Equipment Labour		$ 1,829	$ 1,572	$ 1,619
OH Dist. Lines Labour		$ 95,936	$ 108,056	$ 111,298
Group Insurance		$ 27,260	$ 28,428	$ 29,281
Holidays and Sick Time		$ 18,788	$ 22,238	$ 20,513
OH Dist. Lines Supplies		$ 18,580	$ 15,120	$ 15,574
OH Dist. Transformer Supplies		$ -	$ 709	$ 700
Meter Expense Labour		$ 1,789	$ 1,534	$ 1,500
Meter Expense Supplies		$ 1,074	$ 1,470	$ 1,450
Truck Expense		$ 65,063	$ 68,292	$ 70,332
On Call Expense		$ 7,800	$ 7,800	$ 8,034
WSIB		$ 2,242	$ 2,483	$ 2,500
Taxes Other Than Income Taxes		$ 7,678	$ 7,688	$ 7,700
CPP Expense		$ 7,253	$ 7,982	$ 8,000
EI Expense		$ 3,961	$ 4,039	$ 4,050
EHT Expense		$ 3,394	$ 3,400	$ 3,450
Pension (OMERS)		$ 11,534	$ 16,102	$ 16,585
	$ 263,311	$ 274,181	$ 296,913	$ 302,585

Variance Analysis

* 2006-2007 - Operations and Maintenance for 2007, (Bridge Year) is expected to be higher than 2006 (Historical Year) actual by $22,732 due to additional repairs and maintenance to Chapleau's distribution system over 2006 but compares well with 2005 actual of $291,278 which was a normal year. Salaries and Wages increased by 3% January 1, 2007.
* 2007-2008 - Expectation is to do the same volume work (repairs and maintenance) in 2008. Salaries and Wages will increase by 3% effective January 1, 2008. Material costs and insurance to increase by 3%. Overall incease from 2007 is 1.9% ($5,672)

Billing & Collecting	2006 Board Approved	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Meter Reading		$ 16,933	$ 16,618	$ 17,279
Customer Billing		$ 37,715	$ 39,421	$ 39,725
Collections Overdue Accounts		$ -	$ 823	$ 412
Collection Charges		$ (270)	$ (205)	$ (238)
Bad Debt Expense		$ 9,540	$ 6,950	$ 8,245
Sub Total		$ 63,918	$ 63,607	$ 65,423
Less Bad Debt Expense		$ (9,540)	$ (6,950)	$ (8,245)
Add Write Offs		$ 5,640	$ 9,882	$ 6,934
	$ 65,879	**$ 60,018**	**$ 66,539**	**$ 64,112**

Variance Analysis

2006-2007 - Customer billing clerk in 2006 was off on LTD and lower rate paid to temp. replacement by approx. $3,000

2007-2008 - 2008 costs determined to be the average of 2006/07 plus 3% for increase in payroll as of January 1, 2008.

	2005 Historical Yr	2006 Historical Yr	2007 Bridge Year	2008 Test Year
Write Offs by Class				
Residential	$ 4,572.85	$ 4,476.48	$ 6,023.18	$ 5,024.17
General Service <50kW	$ 706.61	$ 1,163.52	$ 3,858.69	$ 1,909.61
Total Write Offs	**$ 5,279.46**	**$ 5,640.00**	**$ 9,881.87**	**$ 6,933.78**

Outside Services Employed		2006 Historical Yr	2007 Bridge Year	2008 Test Year
Regulatory Compliance Services	Rates Applications, Cost of Service, Dist. Rates Rebasing and interrogatories	$ 3,878	$ 39,675	$ 18,000
KPMG	Annual Audit, PILs Submission, Review for OEB, 3 Year Bus. Plan	$ 16,672	$ 38,387	$ 15,000
Spi Group	EBT License, Maintenance and Monthly Support	$ 6,120	$ 4,120	$ 4,120
Peterborough Utilities	MDMA & MSP Wholesale Meters	$ 17,718	$ 17,754	$ 17,800
MacGillivray Janitorial	Janitorial Services	$ 2,700	$ 2,700	$ 2,700
Valentine Farms Snow Removal	Snow Removal	$ 707	$ 800	$ 800
Hydro One	Weather Normalization	$ -	$ 3,500	$ -
Sudbury Control	Infra Red Scan	$ -	$ 600	$ 600
AESI	ESA Audit	$ -	$ 1,702	$ 1,800
		$ 47,795	**$ 109,238**	**$ 60,820**

Variance Analysis

Historical Year - Bridge Year: Bridge Year increase of $61,443 is maily due to prepararion of CA Model and Rebasing Rates for 2008 by RCS, (increase of $35,797), costs incurred for the OEB review and 3 year business plan pepared by KPMG ($21,715) and the weather normalization data prepared by Hydro One ($3,500).

Bridge Year - Test Year: Test Year expectation is for expenditures to be lower by $48,418. Expected expenditures beyond standard is for RCS to assist with rate rebasing interrogatories in 2008.

Bank Charges	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Bank processing fees	$ 3,537	$ 4,420	$ 4,350
Letter of Credit fee	$ 5,403	$ 5,462	$ 4,850
	$ 8,940	**$ 9,882**	**$ 9,200**

Variance Analysis

2006-2007 - Increase in processing and letter of credit fees in 2007. Letter of credit reduced August 2007 by approx. $100,000 and fee also reduced by $1,160.

2007-2008 - Lower fees in 2008 is due to letter of credit.

Employee Benefit Programs.	2006 Historical Yr.	2007 Bridge Year	2008 Test Year
Holidays And Sick Time	$ 18,788	$ 22,238	$ 21,128
Group Insurance	$ 27,260	$ 28,428	$ 29,281
WSIB	$ 2,242	$ 2,483	$ 2,500
CPP Expense	$ 7,253	$ 7,982	$ 8,000
EI Expense	$ 3,961	$ 4,039	$ 4,050
EHT Expense	$ 3,394	$ 3,400	$ 3,450
Pension (OMERS)	$ 11,534	$ 16,102	$ 16,585
	$ 74,432	**$ 84,672**	**$ 84,994**

Variance Analysis

2006-2007 - 2007 Holiday and Sick Time, increase is due to additional 1 week vacation for 2 employees, increase sick time and increase in salaries and wages of 3%.

- 2006 OMERS Pension is only for May to December. Pension for January to April is in Deferral account number 1508.

2007-2008 - 2008 Holiday and Sick Time is average for 2006 and 2007 plus increase in salaries and wages of 3%.

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (a)

REGULATORY ASSETS and VARIANCES

Retail Settlement Variance Accounts - for 2006

	WMS				NW				CN				Energy				Low Voltage		
	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance			**30663.40**	**5546.68**			**-64326.35**	**-6390.98**			**-230732.66**	**-40267.08**			**-27743.25**	**8330.99**		**0**	**0**
Iterest Rate %																			
Jan. '06	**0.006042**				**0.006042**				**0.006042**				**0.006042**				**0.006042**		
May '06	**0.003450**				**0.003450**				**0.003450**				**0.003450**				**0.003450**		
July '06	**0.003825**				**0.003825**				**0.003825**				**0.003825**				**0.003825**		
January	22719.65	19354.65	34028.40	185.27	17323.64	17345.13	-64347.84	-388.66	9193.28	15014.92	-236554.3	-1394.09	233734.53	178160.82	27830.46	-167.62			
February	16494.5	22501.03	28021.87	205.60	19356.07	20551.43	-65543.20	-388.79	10237.1	17804.34	-244121.54	-1429.26	170645.17	206613.48	-8137.85	168.15			
March	11541.86	22374.1	17189.63	169.31	19847.46	19707.15	-65402.89	-396.01	10176.76	17076.56	-251021.34	-1474.98	181245.06	199475.06	-26367.85	-49.17			
Adjustment			-21747.00	-4168.01			39106.12	7789.63			153615.28	-1326.66			8568.00	2500.00			
April	20533.4	20542.16	-4566.13	103.86	16636.52	17709.05	-27369.30	-395.16	5069.38	15347.39	-107684.07	-1516.67	177095.23	180490.16	-21194.78	-159.31			
May	13133.76	16890.77	-8323.14	-15.75	13937.09	15084.91	-28517.12	-94.42	4265.16	13060.01	-116478.92	-371.51	123563.44	147389.51	-45020.85	-73.12			
June	13749.11	13821.06	-8395.09	-28.71	11073.62	11907.58	-29351.08	-98.38	3585.02	10884.05	-123777.95	-401.85	115295.05	125107.28	-54833.08	-155.32			
July	8098.27	11679.97	-11976.79	-32.11	8772.46	8817.43	-29396.05	-112.27	2723.58	8775.84	-129830.21	-473.45	104968.18	113332.07	-63196.97	-209.74	2387.08	2387.08	0
Aug	8636.6	10210.76	-13550.95	-45.81	8080.65	7700.02	-29015.42	-112.44	2542.18	7723.92	-135011.95	-496.60	107748.29	99307.95	-54756.63	-241.73	1967.65	4354.73	9.13
Sept	8420.14	10622.63	-15753.44	-51.83	7480.14	8046.9	-29582.18	-110.98	2306.98	8074.77	-140779.74	-516.42	88765.12	109375.27	-75366.78	-209.44	1812.61	6167.34	16.66
Oct	7287.15	9850.83	-18317.12	-60.26	7857.06	7736.28	-29461.40	-113.15	2570.26	7757.15	-145966.63	-538.48	106796.14	95585.72	-64156.36	-288.28	1695.14	7862.48	23.59
Nov	9959.89	12474.1	-20831.33	-70.06	10560.7	9918.95	-28819.65	-112.69	3423.52	9954.3	-152497.41	-558.32	152526.93	121597.42	-33226.85	-245.40	2434.68	10297.16	30.07
Dec	14053.45	16481.01	-23258.89	-79.68	12599.08	12227.44	-28448.01	-110.24	3854.94	12280.88	-160923.35	-583.30	159288.13	165391.65	-39330.37	-127.09	2897.74	13194.9	39.39
	154627.78	186803.07			153524.49	156752.27			59948.16	143754.13			1721671.27	1741826.39			13194.90		
		-32175.29	**-23258.89**	**1658.49**		**-3227.78**	**-28448.01**	**-1034.55**		**-83805.97**	**-160923.35**	**-51348.68**		**-20155.12**	**-39330.37**	**9072.91**	**13194.90**	**13194.90**	**118.84**
Adjustment posted to recovery				**-4168.00**				3714.00				17967.00				-3693.00			
				-2509.51				**2679.45**				**-33381.68**				**5379.91**			

Retail Settlement Variance Accounts - for 2007

	WMS				NW				CN				Energy				Low Voltage		
	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Billed Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance			**-23258.89**	**-2509.51**			**-28448.01**	**2679.45**			**-160923.35**	**-33381.68**			**-39330.37**	**5379.91**		**13194.9**	**118.84**
Iterest Rate	**0.003825**				**0.003825**				**0.003825**				**0.003825**				**0.003825**		
January	14237.76	16966.19	-25987.32	-88.97	15355.84	12982.65	-26074.82	-108.81	4525.44	13048.89	-169446.8	-615.53	178488.68	169115.75	-29957.44	-150.44	3194.99	16389.89	50.47
February	21479.41	21626.31	-26134.22	-99.40	16726.07	15703.13	-25051.88	-99.74	5231.54	15814.29	-180029.55	-648.13	241429.08	209848.63	1623.01	-114.59	3728.88	20118.77	62.69
March	20143.55	22620.45	-28611.12	-99.96	18024.23	17106.74	-24134.39	-95.82	5577.96	17224.99	-191676.58	-688.61	211466.62	230338.58	-17248.95	6.21	4218.14	24336.91	76.95
April	14781.42	21276.25	-35105.95	-109.44	17987.86	15877.91	-22024.44	-92.31	5691.92	15977.67	-201962.33	-733.16	168005.4	215035.68	-64279.23	-65.98	4601.43	28938.34	93.09
May	8837.93	19047	-45315.02	-134.28	14708.56	14389.82	-21705.7	-84.24	4707.76	14484.19	-211738.76	-772.51	144630.2	184597.17	-104246.2	-245.87	4284.31	33222.65	110.69
June	9204.53	13109.28	-49219.77	-173.33	10550.72	10316.13	-21471.11	-83.02	3325.26	10354.9	-218768.4	-809.90	96160.46	121971.78	-130057.52	-398.74	3496.26	36718.91	127.08
July	8745.18	10061.89	-50536.48	-188.27	8913.98	8184.04	-20741.17	-82.13	2597.24	8205.51	-224376.67	-836.79	111159.6	94136.43	-113034.35	-497.47	2356.57	39075.48	140.45
Aug	7375.44	10103.78	-53264.82	-193.30	8105.2	7782.99	-20418.96	-79.33	2422.94	7804.14	-229757.87	-858.24	91379.66	96031.66	-117686.35	-432.36	2116.55	41192.03	149.46
Sept *	8469.34	9977.89	-54773.37	-203.74	7326.74	7461.06	-20553.28	-78.10	2326.6	7483.79	-234915.06	-878.82	93095.72	95981.6	-120572.23	-450.15	1921.87	43113.9	157.56
Oct	10424.13	10439.14	-54788.38	-209.51	7948.17	8789.88	-21394.99	-78.62	4556.32	8126.98	-238485.72	-898.55	131012.07	101134.54	-90694.7	-461.19	1695.14	44809.04	164.91
Nov **	13019.33	12143.09	-53912.14	-209.57	9139.2664	10308.9	-22564.624	-81.84	4697.78	9598	-243385.94	-912.21	151838.51	118241.06	-57097.25	-346.91	2434.68	47243.72	171.39
Dec	15589.74	17030.37	-55352.77	-206.21	12415.4712	13658.34	-23807.492	-86.31	5419.76	12668.4	-250634.58	-930.95	163496.17	162095.51	-55696.59	-218.40	2897.74	50141.46	180.71
	152307.76	**184401.64**			**147202.11**	**142561.59**			**51080.52**	**140791.75**			1782162.17	1798528.39			36946.56		
Variance		**-32093.88**	**-55352.77**	**-4425.48**		**4640.5176**	**-23807.492**	**1629.17**		**-89711.225**	**-250634.58**	**-42965.09**		-16366.22	**-55696.59**	**2004.04**	**36946.56**	**50141.46**	**1604.30**

Retail Settlement Variance Accounts - January to April 30, 2008

January	18478.71	18160.42	-55034.48	-211.72	14378.9712	15163.89	-24592.411	-91.06	6034.48	14031.91	-258632.01	-958.68	206111.61	173638.29	-23223.27	-213.04	3194.99	53336.45	191.79
February	18986.96	22063.67	-58111.19	-210.51	15876.1416	18127.28	-26843.55	-94.07	6806.20	16809.32	-268635.13	-989.27	206037.13	208231.06	-25417.2	-88.83	3728.88	57065.33	204.01
March	15842.71	22497.2	-64765.68	-222.28	16663.548	18406.95	-28586.952	-102.68	6932.08	17150.78	-278853.83	-1027.53	196355.84	214906.82	-43968.18	-97.22	4218.14	61283.47	218.27
April	17657.41	20909.21	-68017.48	-247.73	15234.7272	16793.48	-30145.704	-109.35	4734.97	15662.53	-289781.39	-1066.62	172550.32	197762.92	-69180.78	-168.18	4601.43	65884.90	234.41
	70965.79	**83630.50**			**62153.39**	**68491.60**			**24507.73**	**63654.54**			**781054.90**	**794539.09**			**15743.44**		
		-12664.71	**-68017.48**	**-5317.72**		**-6338.212**	**-30145.704**	**1232.02**		**-39146.813**	**-289781.39**	**-47007.18**		**-13484.19**	**-69180.78**	**1436.77**	**15743.44**	**65884.90**	**2452.78**

***Actuals to September 2007 - October to December 2007 (est) used average 2005 and 2006 data.**
- January to April 2008 (est) used average 2006 and 2007 data.
- Transmission rates effective November 1, 2007 to April 30, 2008 have been redused by 12% to minimize variance.

**** Charge accounts for Transmission Network and Connection adjusted to reflect the 12 % reduction as per OEB advice.**

Deferral Accounts

	Pension			Regulatory Costs		
	Charge Accounts	Cumulative Variance	Interest	Charge Accounts	Cumulative Variance	Interest
Opening Balance		**0**	**0**		**0**	**0**
Iterest Rate %						
Jan. '04				**0.0048**		
Jan. '05	**0.003233**					
May '06	**0.003450**			**0.003450**		
July '06	**0.003825**			**0.003825**		
2004						
July				338	338	
Aug				0	338	1.62
Sept				338	676	1.62
Oct				0	676	3.24
Nov				338	1014	3.24
Dec				0	1014	4.87
2005						
January	995.12	995.12	0.00	0	1014	4.87
February	995.12	1990.24	3.22	0	1014	4.87
March	995.12	2985.36	6.43	0	1014	4.87
April	995.12	3980.48	9.65	898.25	1912.25	4.87
May	995.12	4975.6	12.87	0	1912.25	9.18
June	1492.79	6468.39	16.09	898.25	2810.5	9.18
July	995.12	7463.51	20.91	0	2810.5	13.49
Aug	995.12	8458.63	24.13	0	2810.5	13.49
Sept *	995.12	9453.75	27.35	508.25	3318.75	13.49
Oct	995.12	10448.87	30.56	0	3318.75	15.93
Nov	995.12	11443.99	33.78	0	3318.75	15.93
Dec	1492.79	12936.78	37.00	508.25	3827	15.93
2006						
January	1032.95	13969.73	41.82	0	3827	18.37
February	1071.65	15041.38	45.16	0	3827	18.37
March	1117.71	16159.09	48.63	695.5	4522.5	18.37
April	1163.77	17322.86	52.24	0	4522.5	21.71
May	0	17322.86	59.76	0	4522.5	15.60
June	0	17322.86	59.76	0	4522.5	15.60
July	0	17322.86	66.26	0	4522.5	17.30
Aug	0	17322.86	66.26	0	4522.5	17.30
Sept	0	17322.86	66.26	0	4522.5	17.30
Oct	0	17322.86	66.26	0	4522.5	17.30
Nov	0	17322.86	66.26	0	4522.5	17.30
Dec	0	17322.86	66.26	-1014	3508.5	17.30
2007				**Posted to Recovery**		-123.20
January	0	17322.86	66.26	0	3508.5	13.42
February	0	17322.86	66.26	0	3508.5	13.42
March	0	17322.86	66.26	0	3508.5	13.42
April	0	17322.86	66.26	0	3508.5	13.42
May	0	17322.86	66.26	0	3508.5	13.42
June	0	17322.86	66.26	0	3508.5	13.42
July	0	17322.86	66.26	0	3508.5	13.42
Aug	0	17322.86	66.26	0	3508.5	13.42
Sept	0	17322.86	66.26	0.00	3508.5	13.42
Oct	0	17322.86	66.26	0	3508.5	13.42
Nov	0	17322.86	66.26	0	3508.5	13.42
Dec	0	17322.86	66.26	0	3508.5	13.42
2008						
January	0	17322.86	66.26	0	3508.5	13.42
February	0	17322.86	66.26	0	3508.5	13.42
March	0	17322.86	66.26	0	3508.5	13.42
April	0	17322.86	66.26	0	3508.50	13.42
	$ 17,322.86		**$ 1,987.10**	**$ 3,508.50**		**$ 444.02**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (b)

REGULATORY ASSETS and VARIANCES

Year		WMS	NW ***	CN ***	Low Voltage	Energy	Total
2003	**Cost**	$ 212,355.10	$ 175,998.88	$ 55,134.73		$ 1,520,327.01	$ 1,963,815.72
	Revenue	$ 215,545.34	$ 189,711.40	$ 164,175.43		$ 1,611,478.99	$ 2,180,911.16
	Variance	$ (3,190.24)	$ (13,712.52)	$ (109,040.70)		$ (91,151.98)	$ (217,095.44)
2004	**Cost**	$ 202,551.32	$ 160,793.35	$ 50,313.08		$ 1,552,785.53	$ 1,966,443.28
	Revenue	$ 205,570.31	$ 183,106.60	$ 158,481.90		$ 1,570,632.14	$ 2,117,790.95
	Variance	$ (3,018.99)	$ (22,313.25)	$ (108,168.82)		$ (17,846.61)	$ (151,347.67)
2005	**Cost**	$ 205,779.62	$ 152,107.86	$ 59,596.96		$ 1,851,442.13	$ 2,268,926.57
	Revenue	$ 195,348.49	$ 175,395.57	$ 151,806.76		$ 1,737,263.21	$ 2,259,814.03
	Variance	$ 10,431.13	$ (23,287.71)	$ (92,209.80)		$ 114,178.92	$ 9,112.54
2006	**Cost**	$ 154,627.78	$ 153,524.49	$ 59,948.16	$ 13,194.90	$ 1,721,671.27	$ 2,102,966.60
	Revenue	$ 186,803.07	$ 156,752.27	$ 143,754.13	$ -	$ 1,741,826.39	$ 2,229,135.86
	Variance	$ (32,175.29)	$ (3,227.78)	$ (83,805.97)	$ 13,194.90	$ (20,155.12)	$ (126,169.26)
2007 *	**Cost**	$ 152,307.76	$ 147,202.11	$ 51,080.52	$ 36,946.56	$ 1,782,162.17	$ 2,169,699.12
	Revenue	$ 184,401.64	$ 142,561.59	$ 140,791.75	$ -	$ 1,798,528.39	$ 2,266,283.37
	Variance	$ (32,093.88)	$ 4,640.52	$ (89,711.23)	$ 36,946.56	$ (16,366.22)	$ (96,584.25)
2008**	**Cost**	$ 153,467.77	$ 133,612.99	$ 49,457.91	$ 36,946.56	$ 1,751,916.72	$ 2,125,401.95
	Revenue	$ 185,602.36	$ 149,656.93	$ 142,272.94	$ -	$ 1,770,177.39	$ 2,247,709.62
	Variance	$ (32,134.59)	$ (16,043.94)	$ (92,815.03)	$ 36,946.56	$ (18,260.67)	$ (122,307.67)

* **Years 2003 to 2006 are actuals. 2007 is actual to May 31 and estimated From June 1 to December 31.**
** **Year 2008 is the average of 2006 and 2007**
*** **Transmission Rates Cost reduced by 12% from November 2007.**

Average (2006/07/08)	**Cost**	**$ 153,467.77**	**$ 132,750.80**	**$ 53,495.53**	**$ 36,946.56**	**$ 376,660.66**
	Revenue	**$ 185,602.36**	**$ 149,656.93**	**$ 142,272.94**	**$ -**	**$ 477,532.23**
	Variance	**$ (32,134.59)**	**$ (16,906.13)**	**$ (88,777.41)**	**$ 36,946.56**	**$ (100,871.57)**

Customer Class	**Unit of measure**	**Current Rates**			**Calculated Rates Rates**			
		WMS& Rural kWh	**Network**	**Connection**	**WMS& Rural kWh**	**Network**	**Connection**	**Low Voltage**
Residential	**kWh**	**$ 0.0062**	**$ 0.0049**	**$ 0.0050**	**$ 0.0051**	**$ 0.0043**	**$ 0.0019**	**$ 0.0013**
GS <50kW	**kWh**	**$ 0.0062**	**$ 0.0045**	**$ 0.0045**	**$ 0.0051**	**$ 0.0040**	**$ 0.0017**	**$ 0.0013**
GS >50kW	**kW**	**$ 0.0062**	**$ 1.8304**	**$ 1.7882**	**$ 0.0051**	**$ 1.6236**	**$ 0.6724**	**$ 0.4809**
USL	**kWh**	**$ 0.0062**	**$ 0.0045**	**$ 0.0045**	**$ 0.0051**	**$ 0.0040**	**$ 0.0017**	**$ 0.0013**
Sentinel Lights	**kW**	**$ 0.0062**	**$ 1.3874**	**$ 1.4113**	**$ 0.0051**	**$ 1.2307**	**$ 0.5307**	**$ 0.4738**
Street Lights	**kW**	**$ 0.0062**	**$ 1.3804**	**$ 1.3824**	**$ 0.0051**	**$ 1.2245**	**$ 0.5198**	**$ 0.4956**

Calculated rates for Network, Connection and Wholesale were calculated by using the average of 3 years 2006, 2007 and 2008.
For Network and Connection rates, Cost for the 3 Years is reduced by 12 % to reflect lower rates in effect November 1, 2007.
Calculated rates for Low Voltage charges were calculated using the 12 months actual cost from August 2006 to July 2007
of $36,946.56 and the average consumptions of 2006, 2007 and 2008 (see below).

Low Voltage Rate Calculation

	Total	**Residential**	**GS <50kW**	**GS >50kW**	**USL**	**Sent. Lights**	**Street Lights**
Estimated Consumpion 2008. (From Sheet '1- Customer Data")							
kWh	28,200,840	14,611,894	5,492,773	7,770,248	6,991	23,871	295,064
Customer class Allocation	100%	51.81%	19.48%	27.55%	0.02%	0.08%	1.05%
kW	22,015	-	-	21,169	-	66	780
Low Voltage Cost Allocation	**$ 36,946.56**	$ 19,143.22	$ 7,196.15	$ 10,179.90	$ 9.16	$ 31.27	$ 386.57
Proposed Low Voltage Rate		**$ 0.0013**	**$ 0.0013**	**$ 0.4809**	**$ 0.0013**	**$ 0.4738**	**$ 0.4956**

PROPOSAL.

Based on the above comparison of current to calculated rates it's recomented that Chapleau PUC adopt the following rates :

- **Current WMS and Rural rate of $0.0052 and $0.0010 to be reduced to the calculated rate of $0.0051 being WMS $0.0041 and Rural $0.0010.**
- **Transmission Network and Connection rates to be reduced to the calculated rates.**
- **Low Voltage rates to be adopted as calculated above.**

Customer Class	**Unit of measure**	**Proposed Rates**				
		WMS/kWh	**Rural/kWh**	**Network**	**Connection**	**Low Voltage**
Residential	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0043**	**$ 0.0019**	**$ 0.0013**
GS <50kW	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0040**	**$ 0.0017**	**$ 0.0013**
GS >50kW	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.6236**	**$ 0.6724**	**$ 0.4809**
USL	**kWh**	**$ 0.0041**	**$ 0.0010**	**$ 0.0040**	**$ 0.0017**	**$ 0.0013**
Sentinel Lights	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.2307**	**$ 0.5307**	**$ 0.4738**
Street Lights	**kW**	**$ 0.0041**	**$ 0.0010**	**$ 1.2245**	**$ 0.5198**	**$ 0.4956**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 5 (c)

REGULATORY ASSETS	Account Number	Opening Balance at Jan. 1/07	Charges Net of Revenue to Dec. 31, 2007	Charges Net of Revenue to Apr. 30/08	Interest to Apr. 30/08	TOTAL CLAIM
RSVA - Wholesale Market Service Charge	1580	$ (23,258.89)	$ (32,093.88)	$ (12,664.71)	$ (5,317.72)	$ (73,335.20)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -	$ -
RSVA - Retail Transmission Network Charge	1584	$ (28,448.01)	$ 4,640.52	$ (6,338.12)	$ 12,320.20	$ (17,825.41)
RSVA - Retail Transmission Connection Charge	1586	$ (160,923.35)	$ (89,711.23)	$ (39,146.81)	$ (47,007.18)	$ (336,788.57)
RSVA - Power	1588	$ (39,330.37)	$ (16,366.22)	$ (13,484.19)	$ 1,436.77	$ (67,744.01)
Low Voltage Charges	1550	$ 13,194.90	$ 36,946.56	$ 15,743.44	$ 2,452.78	$ 68,337.68
Other Reg. Assets (Pension and OEB Assessment)	1508	$ 20,831.36	$ -	$ -	$ 2,431.12	$ 23,262.48
TOTAL		$ (217,934.36)	$ (96,584.25)	$ (55,890.39)	$ (33,684.03)	$ (404,093.03)

Rate Rider Calculation		**Total**	**Residential**	**GS <50kW**	**GS >50kW**	**USL**	**Sent. Lights**	**Street Lights**
Estimated Consumption 2008. (From "Exhibit 3(a) Op. Rev. (Data 1)")								
kWh		28,200,840	14,611,894	5,492,773	7,770,248	6,991	23,871	295,064
Customer class Allocation		100%	51.8137%	19.4773%	27.5533%	0.0248%	0.0846%	1.0463%
kW		21,925	-	-	21,079	-	66	780
RSVA - Wholesale Market Service Charge	1580	$ (73,335.20)	$ (37,997.67)	$ (14,283.74)	$ (20,206.23)	$ (18.18)	$ (62.07)	$ (767.30)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RSVA - Retail Transmission Network Charge	1584	$ (17,825.41)	$ (9,236.00)	$ (3,471.92)	$ (4,911.48)	$ (4.42)	$ (15.09)	$ (186.51)
RSVA - Retail Transmission Connection Charge	1586	$ (336,788.57)	$ (174,502.56)	$ (65,597.45)	$ (92,796.20)	$ (83.49)	$ (285.08)	$ (3,523.80)
RSVA - Power	1588	$ (67,744.01)	$ (35,100.67)	$ (13,194.73)	$ (18,665.68)	$ (16.79)	$ (57.34)	$ (708.80)
Low Voltage Charges	1550	$ 68,337.68	$ 35,408.27	$ 13,310.36	$ 18,829.25	$ 16.94	$ 57.84	$ 715.01
Other Reg. Assets (Pension and OEB Assessment)	1508	$ 23,262.48	$ 12,053.15	$ 4,530.91	$ 6,409.57	$ 5.77	$ 19.69	$ 243.39
TOTAL		$ (404,093.03)	$ (209,375.47)	$ (78,706.56)	$ (111,340.77)	$ (100.17)	$ (342.05)	$ (4,228.00)
Balance to be collected/refunded		$ (404,093.03)	$ (209,375.47)	$ (78,706.56)	$ (111,340.77)	$ (100.17)	$ (342.05)	$ (4,228.00)
Rate per kWh/kW - Over 1 Year		$ (404,093.03)	$ (0.0143)	$ (0.0143)	$ (5.2820)	$ (0.0143)	$ (5.1825)	$ (5.4205)
Rate per kWh/kW - Over 2 Years		$ (202,046.52)	$ (0.0072)	$ (0.0072)	$ (2.6410)	$ (0.0072)	$ (2.5913)	$ (2.7103)
Rate per kWh/kW - Over 4 Years	*	**$ (101,023.26)**	**$ (0.0036)**	**$ (0.0036)**	**$ (1.3205)**	**$ (0.0036)**	**$ (1.2956)**	**$ (1.3551)**
Rate per kWh/kW - Over 6 Years		$ (67,348.84)	(0.0024)	(0.0024)	(0.8803)	(0.0024)	(0.8638)	(0.9034)
Rate per kWh/kW - Over 8 Years		$ (50,511.63)	(0.0018)	(0.0018)	(0.6602)	(0.0018)	(0.6478)	(0.6776)

* **The recommended option by CPUC is to refund the over collection of regulatory assets over a 4 year period that will allow CPUC to retain sufficient cash for its day to day operations.**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170

EDR File Number: EB-2005-0349

Cost Allocation File Number: EB-2007-0001

EXHIBIT 6

COST OF CAPITAL AND RATE OF RETURN

Capital Structure	Board Approved 2006		Historical Year 2006		Test Year 2008	
Long-Term Debt	$ 1,853,685	99.99%	$ 1,321,493	58.9%	$ 1,195,551	53.3%
Short-Term Debt/Unfunded Debt	$ -		$ 360,727	16.1%	$ -	
Total Debt	$ 1,853,685	99.99%	$ 1,682,220	75.0%	$ 1,195,551	53.3%
Preference Shares	$ -	0.00%	$ -	0.0%	$ -	0.0%
Common Equity	$ 100	0.01%	$ 560,840	25.0%	$ 1,047,509	46.7%
Total Equity	$ 100	0.01%	$ 560,840	25.0%	$ 1,047,509	46.7%
Total Rate Base	$ 1,853,785	100.0%	$ 2,243,060	100.0%	$ 2,243,060	100.0%

Long Term Debt is payable to the Township of Chapleau for an unspecified term at a debt rate cost of 7.25%

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Pro Forma Operating Statements

	2006 Historical Actual	Bridge Year 2007	Test Year 2008
Assets			
Current Assets:			
Cash	173,608	174,637	176,298
Term Deposits and Treasury Bills	651,121	803,000	790,000
Trade Receivable	40,885	40,885	40,885
Plant Material and Supplies	43,787	43,787	43,787
Prepaid Expenses	10,318	10,318	10,318
Unbilled revenue - Energy sales	424,856	424,856	424,856
Unbilled revenue - Distribution	42,940	42,940	42,940
	1,387,515	1,540,423	1,529,084
Capital Assets	2,175,939	2,185,341	2,249,202
Accumulated Dipreciation	1,266,778	1,303,051	1,339,614
	909,161	882,290	909,588
	2,296,676	2,422,713	2,438,672
Liabilities and Shareholder's Equity			
Current Liabilities			
Accounts Payable and accrued Liabilities	267,048	270,548	266,874
Advanses from Related Companies	20,551	20,551	20,551
	287,599	291,099	287,425
Other Liabilities			
Regulatory Liabilities	487,538	601,613	572,678
Customer Deposits	21,989	21,989	21,989
Loan Payable	360,727	360,727	-
Mortgage Payable	1,321,493	1,321,493	1,195,551
Shareholders Deficiency			
Share Capital	560,840	560,840	1,047,509
Deficit	(743,510)	(735,048)	(686,480)
	(182,670)	(174,208)	361,029
	2,296,676	2,422,713	2,438,672

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1
Revenue Sufficiency (Proposed Base Rates)

Pro Forma Operating Statements

	2006 Historical Board Approved	2006 Historical Actual	2007 Budget	YTD to July Budget	Aug. - Dec. Forecast	YTD Actual Jul. 2007	Bridge Year 2007	Test Year 2008	Forecast 2009
Revenue									
Distribution Revenue	**$ 590,145**	**$ 567,925**	$ 555,545	$ 372,720	$ 202,280	$ 392,265	**$ 592,434**	**$ 680,023**	$ 723,158
SSS Admin. and Retailer Charges	**$ -**	**$ 1,382**	$ 1,735	$ 1,012	$ 723	$ 1,012	**$ 1,735**	**$ 1,735**	$ 1,735
Miscellaneous Revenue	**$ 42,681**	**$ 42,657**	$ 36,804	$ 21,469	$ 7,835	$ 33,389	**$ 52,304**	**$ 43,244**	$ 36,800
Revenue	$ 632,826	$ 611,964	$ 594,084	$ 395,201	$ 210,838	$ 426,666	**$ 646,473**	**$ 725,002**	$ 761,693
Cost of Energy Revenue	**0**	**$ 2,089,075**	$ 2,322,000	$ 1,550,000	$ 666,311	$ 1,151,339	**$ 1,782,162**	**$ 1,751,917**	$ 1,767,040
Cost of Energy Expense	**0**	**$ 2,089,075**	$ 2,322,000	$ 1,550,000	$ 666,311	$ 1,151,339	**$ 1,782,162**	**$ 1,751,917**	$ 1,767,040
Cost of Power	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**	**$ -**	$ -
Operations and Maintenance	**$ 263,311**	**$ 262,647**	$ 300,000	$ 175,000	$ 131,528	$ 168,472	**$ 296,913**	**$ 302,585**	$ 308,637
Billing & Collecting	**$ 65,879**	**$ 63,918**	$ 60,000	$ 35,000	$ 34,103	$ 25,897	**$ 66,539**	**$ 64,112**	$ 66,035
Depreciation	**$ 37,890**	**$ 37,370**	$ 36,000	$ 21,000	$ 15,125	$ 21,148	**$ 36,273**	**$ 36,563**	$ 42,977
Administrative and General Expenses									
Community Relations	**$ 2,607**	**$ 1,707**	$ 2,400	$ 1,400	$ 1,000	$ 63	**$ 1,063**	**$ 1,200**	$ 1,200
Executive Salaries and Expense	**$ 59,881**	**$ 59,331**	$ 60,000	$ 35,000	$ 25,000	$ 37,672	**$ 62,672**	**$ 64,552**	$ 66,489
Office Supplies and Expense	**$ 22,176**	**$ 19,432**	$ 21,000	$ 12,250	$ 8,750	$ 12,911	**$ 21,661**	**$ 22,248**	$ 22,915
Outside Services Employed	**$ 38,352**	**$ 47,795**	$ 57,000	$ 33,250	$ 47,948	$ 61,290	**$ 109,238**	**$ 60,820**	$ 60,000
Property Insurance	**$ 13,601**	**$ 12,119**	$ 18,000	$ 10,500	$ 9,657	$ 8,343	**$ 13,000**	**$ 13,500**	$ 18,000
Regulatory Expenses	**$ 5,734**	**$ 4,584**	$ 12,000	$ 7,000	$ 8,551	$ 3,449	**$ 5,769**	**$ 6,000**	$ 12,000
Misc. General Expenses	**$ 6,546**	**$ 10,612**	$ 12,000	$ 7,000	$ 8,901	$ 6,099	**$ 15,000**	**$ 12,000**	$ 12,000
Bank Charges	**$ 8,247**	**$ 8,941**	$ 11,100	$ 9,000	$ 2,100	$ 9,395	**$ 9,883**	**$ 9,200**	$ 10,000
Low Voltage Charges (8 Moths Only)	**$ -**	**$ -**	$ -	$ -	$ -	$ -	**$ -**	**$ 24,631**	$ 36,947
Total Expenses	**$ 524,224**	**$ 528,456**	$ 589,500	$ 346,400	$ 292,663	$ 354,739	**$ 638,011**	**$ 617,411**	$ 657,200
Income (Loss)	**$ 108,602**	**$ 83,508**	**$ 4,584**	**$ 48,801**	**$ (81,826)**	**$ 71,927**	**$ 8,462**	**$ 107,591**	**$ 104,493**
Interest Payable to Township of Chapleau	**$ 48,454**	**$ -**	$ 45,000	$ 26,250	$ 45,000	$ -	**$ 45,000**	**$ 45,000**	45000
Net Income (Loss)	**$ 60,148**	**$ 83,508**	$ (40,416)	$ 22,551	$ (126,826)	$ 71,927	**$ (36,538)**	**$ 62,591**	$ 59,493
Adjustments For Cash Flow									
Depreciation			$ 36,000	$ 21,000	$ 15,105	$ 21,148	$ 36,273	$ 36,563	
Purchase of Capital assets					$ (1,500)	$ (6,902)	$ (8,402)	$ (63,861)	
Ovecollection/(Refund) of Regulatory Assets					$ 36,439	$ 51,015	$ 87,454	$ (38,886)	
Change in Accounts Reaceivable			$ 3,500	$ 13,000	$ 3,500	$ -	$ 3,500	$ -	
Net Cash Flow			$ (916)	$ 56,551	$ (108,221)	$ 93,075	$ 82,287	$ (3,593)	
Cash Biginning of the Year			$ 172,400	$ 172,400	$ 228,951	$ 172,400	$ 824,729	$ 907,016	
Cash End of the Year			$ 171,484	$ 228,951	$ 120,731	$ 265,475	$ 907,016	$ 903,422	

Cash Flow Forecast 2008 to 2012	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Cash Biginning of the Year	**$ 824,729**	**$ 907,016**	**$ 931,082**	**$ 500,961**	**$ 453,059**	**$ 446,714**
Net Income (Loss)	**$ (36,538)**	**$ 62,591**	**$ 59,493**	**$ 50,000**	**$ 50,000**	**$ 50,000**
Adjustments For Cash Flow						
Depreciation	**$ 36,273**	**$ 36,563**	**$ 42,977**	**$ 52,885**	**$ 51,910**	**$ 50,123**
Purchase of Capital Assets	**$ (8,402)**	**$ (63,861)**	**$ (431,568)**	**$ (49,764)**	**$ (7,232)**	**$ (7,232)**
Net Ovecollection/(Refund) of Regulatory Assets	**$ 107,647**	**$ (11,226)**	**$ (101,023)**	**$ (101,023)**	**$ (101,023)**	**$ (33,674)**
Change in Accounts Reaceivable	**$ 3,500**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Cash End of the Year	**$ 927,209**	**$ 931,082**	**$ 500,961**	**$ 453,059**	**$ 446,714**	**$ 505,931**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 1

Revenue Deficiency (Current Base Rates to Continue)

	Historical Actual	(Forecast - Current Rates) Bridge Year	Test Year	
Revenue	**2006**	**2007**	**2008**	**2009**
Distribution Revenue	$ 558,385	$ 592,434	$ 619,408	$ 619,631
SSS Admin. and Retailer Charges	$ 1,382	$ 1,735	$ 1,735	$ 1,735
Miscellaneous Revenue	$ 42,657	$ 52,304	$ 43,244	$ 36,800
	$ 602,424	$ 646,473	$ 664,387	$ 658,166
Expenses				
Operations and Maintenance	$ 262,647	$ 296,913	$ 302,585	311,663
Administrative and General Expenses	$ 164,521	$ 238,286	$ 214,151	239,551
Billing & Collecting	$ 63,918	$ 66,539	$ 64,112	66,035
Depreciation	$ 37,370	$ 36,273	$ 36,563	42,977
Profit (Loss)	$ 73,968	$ 8,462	$ 46,976	$ (2,060)
Interest Payable to Township of Chapleau	$ -	$ 45,000	$ 45,000	$ 45,000
Profit (Loss)	$ 73,968	$ (36,538)	$ 1,976	$ (47,060)

Cash Flow Forecast 2008 to 2012

	2006	2007	2008	2009	2010	2011	2012
Cash Biginning of the Year	$ 1,022,702	$ 824,729	$ 925,209	$ 888,661	$ 351,987	$ 194,085	$ 77,740
Net Income (Loss)	$ 119,469	$ (36,538)	$ 1,976	$ (47,060)	$ (60,000)	$ (60,000)	$ (60,000)
Adjustments For Cash Flow							
Depreciation	$ 37,370	$ 36,273	$ 36,563	$ 42,977	$ 52,885	$ 51,910	$ 50,123
Purchase of Capital Assets	$ 24,292	$ (6,902)	$ (63,861)	$ (431,568)	$ (49,764)	$ (7,232)	$ (7,232)
Net Ovecollection/(Refund) of Regulatory Assets	$ (126,169)	$ 107,647	$ (11,226)	$ (101,023)	$ (101,023)	$ (101,023)	$ (33,674)
Change in Accounts Reaceivable & other.	$ (252,935)	$ -	$ -	$ -	$ -	$ -	$ -
Cash End of the Year	$ 824,729	$ 925,209	$ 888,661	$ 351,987	$ 194,085	$ 77,740	$ 26,957

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 8 (a)

COST ALLOCATION TO BASE REVENUE REQUIREMENT

Results from the 2006 Cost Allocation Information Filing	Total Current Revenue (From 2006 EDR Model)	Revenue Requirement (From CA Model)	Adjustment Required to Total Current Revenue	% Revenue Requirement (Per CA Model)
RESIDENTIAL				
Regular	462,269	407,234	(55,035)	63.20%
GENERAL SERVICE				
Less than 50 kW	118,553	129,751	11,198	20.14%
Greater than 50 kW (to 3000 kW)	55,037	69,856	14,819	10.84%
Unmetered Scattered Load	1,690	2,148	458	0.33%
Sentinel Lighting	1,107	2,441	1,334	0.38%
Street Lighting	5,729	32,955	27,226	5.11%
TOTALS	**644,385**	**644,385**	**0**	**100.00%**

Cost Allocation to 2008 Revenue Requirement	Total Revenue as Calculated Exhibit9(a) L31-L36	Cost Allocated Revenue Requirement	Adjustment Required to Revenue as Calculated	Proposed Adjustment to Revenue as Calculated	Proposed Cost Allocated Revenue Requirement
RESIDENTIAL					
Regular	494,842	435,125	(59,716)	$ (32,221)	$ 462,621
GENERAL SERVICE					
Less than 50 kW	125,924	138,638	12,714	$ 12,714	$ 138,638
Greater than 50 kW (to 3000 kW)	59,244	74,640	15,397	$ 15,397	$ 74,640
Unmetered Scattered Load	1,357	2,295	938	$ 130	$ 1,487
Sentinel Lighting	1,170	2,608	1,438	$ 480	$ 1,650
Street Lighting	5,982	35,212	29,230	$ 3,500	$ 9,482
TOTALS	**688,519**	**688,519**	**0**	**$ -**	**$ 688,519**

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Allocation - Base Revenue Requirement

	Number of Customers (Connections)	kWh per Customer			Calculated kWh per Customer	Calculated kWh	kW per Customer			Calculated kW per Customer	Calculated kW
	2008 Customer count	2006	2007	2008	3 yr average per customer	2008 cust. count x 3 yr average per cust.	2006	2007	2008	3 yr average per customer	2008 cust. count x 3 yr average per cust.
RESIDENTIAL											
Regular	1,177	12,284.2	12,544.8	12,414.5	12,414.5	14,611,894	0.0	0.0	0.0	0.0	0.0
Less than 50 kW	166	32,877.4	33,395.6	32,994.1	33,089.0	5,492,773	0.0	0.0	0.0	0.0	0.0
Greater than 50 kW (to 3000 kW)	14	551,654.5	557,255.3	556,143.4	555,017.7	7,770,248	1,492.4	1,512.5	1,512.1	1,505.7	21,079.3
Unmetered Scattered Load	6	1,128.3	1,202.0	1,165.2	1,165.2	6,991	0.0	0.0	0.0	0.0	0.0
Sentinel Lighting	24	974.9	1,014.3	994.6	994.6	23,871	2.8	2.8	2.8	2.8	66.0
Street Lighting	341	863.6	866.9	865.3	865.3	295,064	2.3	2.3	2.3	2.3	780.0
TOTALS	1,728					28,200,840					21,925.3

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Allocation - Base Revenue Requirement

	Calculated Revenue for Allocation to Customer Classes: 2008 Consumption determinants x Existing Rates for 2007				Allocation to Customer Classes	Allocation between Fixed and Variable %			Base Revenue Requirement Allocated (adjusted for Transformer Credit)		
	Volumetric kWh ($)	Volumetric kW ($)	Monthly Fixed Charges ($)	Total ($)	Total for customer class as % of Total for all classes	Volumetric as percent of Total for customer	Fixed charges as percent of total for customer		Overall Allocation to Classes	Variable Component	Fixed Component
RESIDENTIAL											
Regular	146,119	0	281,350	427,469	71.87%	34.18%	65.82%	100.00%	494,842	169,149	325,693
Less than 50 kW	46,689	0	62,091	108,779	18.29%	42.92%	57.08%	100.00%	125,924	54,047	71,877
Greater than 50 kW (to 3000 kW)	0	25,504	25,674	51,178	8.60%	49.83%	50.17%	100.00%	59,244	29,524	29,720
Unmetered Scattered Load	59	0	1,113	1,173	0.20%	5.07%	94.93%	100.00%	1,357	69	1,289
Sentinel Lighting	0	247	763	1,011	0.17%	24.48%	75.52%	100.00%	1,170	286	883
Street Lighting	0	1,894	3,274	5,168	0.87%	36.66%	63.34%	100.00%	5,982	2,193	3,790
TOTALS	192,867	27,646	374,264	594,777	100.00%	37.07%	62.93%	100.00%	**688,521**	**255,268**	**433,253**
									9,610	<< Less Transformer Credit	
									678,911	<< Base Revenue Req. B.R.R.#	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (a)

Rates - Base Revenue Requirement

	Number of Customers (Connections)	kWh	kW	Base Revenue Requirement Allocated		Base Rates - Revenue Requirement *divided by consumption plus Low Voltage Rates* for 2008.			
	2008 Customer count	2008 cust. count x 3 yr per cust. avg. kWh	2008 cust. count x 3 yr per cust. avg. kW	Variable Component	Fixed Component	Volumetric Rate Type	Rate per kWh $	Rate per kW $	Fixed service charge $
RESIDENTIAL									
Regular	1,177	14,611,894	0	169,149	325,693	kWh	0.0129		23.06
GENERAL SERVICE									
Less than 50 kW	166	5,492,773	0	54,047	71,877	kWh	0.0111		36.08
Greater than 50 kW (to 3000 kW)	14	7,770,248	21,079	29,524	29,720	kW		1.8825	176.91
Unmetered Scattered Load	6	6,991	0	69	1,289	kWh	0.0111		17.90
Sentinel Lighting	24	23,871	66	286	883	kW		4.8130	3.07
Street Lighting	341	295,064	780	2,193	3,790	kW		3.3070	0.93
TOTALS	1,728	28,200,840	21,925	**255,268**	**433,253**				

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT 9 (b)

Cost Allocation - Base Revenue Requirement / Proposed Rates

	Cost Allocated Base Revenue Requirement Between Fixed and Variable and Adjusted for Transformer Credit			Number of Customers (Connections)	kWh	kW	Base Rates - Revenue Requirement for 2008 test yr. + Low Voltage Charge + Meter Charge $0.26 for Metered Cusomers..			
	Cost Allocation to Classes from Exhibit3(d) F25 - F31	Variable Component	Fixed Component	2008 Customer count	2008 cust. count x 3 yr per cust. avg. kWh	2008 cust. count x 3 yr per cust. avg. kW	Volumetric Rate Type	Rate per kWh $	Rate per kW $	Fixed service charge $
RESIDENTIAL										
Regular	462,621	158,135	304,486	1,177	14,611,894	0	kWh	0.0121		21.82
GENERAL SERVICE										
Less than 50 kW	138,638	59,504	79,134	166	5,492,773	0	kWh	0.0121		39.99
Greater than 50 kW (to 3000 kW)	74,640	37,196	37,444	14	7,770,248	21,079	kW		2.2455	223.14
Unmetered Scattered Load	1,487	75	1,412	6	6,991	0	kWh	0.0121		19.61
Sentinel Lighting	1,650	404	1,246	24	23,871	66	kW		6.5934	4.33
Street Lighting	9,482	3,476	6,007	341	295,064	780	kW		4.9518	1.47
TOTALS	**688,521**	258,790	429,729	1,728	28,200,840	21,925				
	9,610	<< Less Transformer Credit								
	678,911	<< Base Rev. Req. B.R.R.#1								

Chapleau Public Utilities Corporation

Tariff OF RATES AND CHARGES
Effective May 1, 2008

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	21.82
Distribution Volumetric Rate	$/kWh	0.0121
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	39.99
Distribution Volumetric Rate	$/kWh	0.0121
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	223.14
Distribution Volumetric Rate	$/kW	2.2455
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	(1.3205)
Retail Transmission Rate – Network Service Rate	$/kW	1.6236
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.6724
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Unmetered Scattered Load

Service Charge	$	19.61
Distribution Volumetric Rate	$/kWh	0.0121
Rate Rider 1 (if applicable)	$/kWh	0.0000
Rate Rider 2 (if applicable)	$/kWh	0.0000
Regulatory Asset Recovery	$/kWh	(0.0036)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0017
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kWh	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kWh	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Sentinel Lighting

Service Charge	$	4.33
Distribution Volumetric Rate	$/kW	6.5934
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	(1.2956)
Retail Transmission Rate – Network Service Rate	$/kW	1.2307
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5307
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Street Lighting

Service Charge	$	1.47
Distribution Volumetric Rate	$/kW	4.9518
Rate Rider 1 (if applicable)	$/kW	0.0000
Rate Rider 2 (if applicable)	$/kW	0.0000
Regulatory Asset Recovery	$/kW	(1.3551)
Retail Transmission Rate – Network Service Rate	$/kW	1.2245
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	0.5198
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Network Service Rate (if applicable)	$/kW	0.0000
Retail Transmission Rate – Line and Transformation Connection Service Rate (if applicable)	$/kW	0.0000
Wholesale Market Service Rate	$/kWh	0.0041
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

Specific Service Charges

Customer Administration

Arrears certificate	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
	$	0.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Disconnect/Reconnect at meter - during regular hours	$	60.00
	$	0.00

Install/Remove load control device - during regular hours	$	65.00
Specific Charge for Access to the Power Poles $/pole/year	$	22.35
	$	0.00

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
	$/kW	0.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0613
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0506
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045
	0.0000

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

EXHIBIT

Customer Impacts - Annualized Average

Residential

Consumption	0 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 21.82	$ 1.90	9.54%	100.00%
Distribution (kWh)	0	$ 0.0100	$ -	0	$ 0.0121	$ -	$ -	0.00%	0.00%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	0	$ 0.0007	$ -	0	-$ 0.0036	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 19.92**			**$ 21.82**	**$ 1.90**	**9.54%**	**100.00%**
Other Charges (kWh)	0	$ 0.0231	$ -	0	$ 0.0183	$ -	$ -	0.00%	0.00%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	0	$ 0.0580	$ -	0	$ 0.0580	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 19.92**			**$ 21.82**	**$ 1.90**	**9.54%**	**100%**
GST (6%)			**$ 1.20**			**$ 1.31**	**$ 0.11**	**9.54%**	
Total Bill after Taxes			**$ 21.12**			**$ 23.13**	**$ 2.01**	**9.54%**	

Residential

Consumption	250 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 21.82	$ 1.90	9.54%	49.48%
Distribution (kWh)	250	$ 0.0100	$ 2.50	250	$ 0.0121	$ 3.03	$ 0.5250	21.00%	6.86%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	250	$ 0.0007	$ 0.18	250	-$ 0.0036	-$ 0.90	$ (1.08)	-614.29%	-2.04%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 22.60**			**$ 23.95**	**$ 1.35**	**5.97%**	**54.30%**
Other Charges (kWh)	264	$ 0.0231	$ 6.10	264	$ 0.0183	$ 4.83	$ (1.27)	-20.78%	10.96%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	264	$ 0.0580	$ 15.32	264	$ 0.0580	$ 15.32	$ -	0.00%	34.74%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 44.02**			**$ 44.10**	**$ 0.08**	**0.19%**	**100%**
GST (6%)			**$ 2.64**			**$ 2.65**	**$ 0.00**	**0.19%**	
Total Bill after Taxes			**$ 46.66**			**$ 46.74**	**$ 0.09**	**0.19%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Residential

Consumption	500 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 21.82	$ 1.90	9.54%	32.87%
Distribution (kWh)	500	$ 0.0100	$ 5.00	500	$ 0.0121	$ 6.05	$ 1.0500	21.00%	9.11%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	500	$ 0.0007	$ 0.35	500	-$ 0.0036	-$ 1.80	$ (2.15)	-614.29%	-2.71%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 25.27**			**$ 26.07**	**$ 0.80**	**3.17%**	**39.28%**
Other Charges (kWh)	528	$ 0.0231	$ 12.20	528	$ 0.0183	$ 9.67	$ (2.54)	-20.78%	14.56%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	528	$ 0.0580	$ 30.64	528	$ 0.0580	$ 30.64	$ -	0.00%	46.16%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 68.11**			**$ 66.38**	**$ (1.74)**	**-2.55%**	**100%**
GST (6%)			**$ 4.09**			**$ 3.98**	**$ (0.10)**	**-2.55%**	
Total Bill after Taxes			**$ 72.20**			**$ 70.36**	**$ (1.84)**	**-2.55%**	

Residential

Consumption	1,000 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 21.82	$ 1.90	9.54%	19.27%
Distribution (kWh)	1,000	$ 0.0100	$ 10.00	1,000	$ 0.0121	$ 12.10	$ 2.1000	21.00%	10.69%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	1,000	$ 0.0007	$ 0.70	1,000	-$ 0.0036	-$ 3.60	$ (4.30)	-614.29%	-3.18%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 30.62**			**$ 30.32**	**-$ 0.30**	**-0.98%**	**26.78%**
Other Charges (kWh)	1057	$ 0.0231	$ 24.41	1057	$ 0.0183	$ 19.33	$ (5.07)	-20.78%	17.07%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	800	$ 0.0580	$ 46.40	800	$ 0.0580	$ 46.40	$ -	0.00%	40.98%
Cost of Power Commodity (kWh)	257	$ 0.0670	$ 17.19	257	$ 0.0670	$ 17.19	$ -	0.00%	15.18%
Total Bill before Taxes			**$ 118.61**			**$ 113.24**	**$ (5.37)**	**-4.53%**	**100%**
GST (6%)			**$ 7.12**			**$ 6.79**	**$ (0.32)**	**-4.53%**	
Total Bill after Taxes			**$ 125.73**			**$ 120.03**	**$ (5.69)**	**-4.53%**	

Residential

Consumption	2,000 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 19.92			$ 21.82	$ 1.90	9.54%	10.30%
Distribution (kWh)	2,000	$ 0.0100	$ 20.00	2,000	$ 0.0121	$ 24.20	$ 4.2000	21.00%	11.42%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	2,000	$ 0.0007	$ 1.40	2,000	-$ 0.0036	-$ 7.20	$ (8.60)	-614.29%	-3.40%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 41.32**			**$ 38.82**	**-$ 2.50**	**-6.05%**	**18.32%**
Other Charges (kWh)	2113	$ 0.0231	$ 48.81	2113	$ 0.0183	$ 38.67	$ (10.14)	-20.78%	18.25%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	800	$ 0.0580	$ 46.40	800	$ 0.0580	$ 46.40	$ -	0.00%	21.90%
Cost of Power Commodity (kWh)	1,313	$ 0.0670	$ 87.97	1,313	$ 0.0670	$ 87.97	$ -	0.00%	41.52%
Total Bill before Taxes			**$ 224.50**			**$ 211.86**	**$ (12.64)**	**-5.63%**	**100%**
GST (6%)			**$ 13.47**			**$ 12.71**	**$ (0.76)**	**-5.63%**	
Total Bill after Taxes			**$ 237.97**			**$ 224.57**	**$ (13.40)**	**-5.63%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service Less Than 50 kW

Consumption 0 kWh 0 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 39.99	$ 8.82	28.30%	100.00%
Distribution (kWh)	0	$ 0.0085	$ -	0	$ 0.0121	$ -	$ -	0.00%	0.00%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	0	-$ 0.0001	$ -	0	-$ 0.0036	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 31.17**			**$ 39.99**	**$ 8.82**	**28.30%**	**100.00%**
Other Charges (kWh)	0	$ 0.0222	$ -	0	$ 0.0178	$ -	$ -	0.00%	0.00%
Other Charges (kW)	0	$ -	$ -	0		$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	0	$ 0.0580	$ -	0	$ 0.0580	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 31.17**			**$ 39.99**	**$ 8.82**	**28.30%**	**100%**
GST (6%)			**$ 1.87**			**$ 2.40**	**$ 0.53**	**28.30%**	
Total Bill after Taxes			**$ 33.04**			**$ 42.39**	**$ 9.35**	**28.30%**	

General Service Less Than 50 kW

Consumption 2,000 kWh 0 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 39.99	$ 8.82	28.30%	17.43%
Distribution (kWh)	2,000	$ 0.0085	$ 17.00	2,000	$ 0.0121	$ 24.20	$ 7.2000	42.35%	10.55%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	2,000	-$ 0.0001	-$ 0.20	2,000	-$ 0.0036	-$ 7.20	$ (7.00)	3500.00%	-3.14%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 47.97**			**$ 56.99**	**$ 9.02**	**18.80%**	**24.84%**
Other Charges (kWh)	2113	$ 0.0222	$ 46.91	2113	$ 0.0178	$ 37.61	$ (9.30)	-19.82%	16.39%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	18.96%
Cost of Power Commodity (kWh)	1,363	$ 0.0670	$ 91.32	1,363	$ 0.0670	$ 91.32	$ -	0.00%	39.80%
Total Bill before Taxes			**$ 229.70**			**$ 229.42**	**$ (0.28)**	**-0.12%**	**100%**
GST (6%)			**$ 13.78**			**$ 13.77**	**$ (0.02)**	**-0.12%**	
Total Bill after Taxes			**$ 243.48**			**$ 243.19**	**$ (0.29)**	**-0.12%**	

General Service Less Than 50 kW

Consumption 10,000 kWh 0 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 31.17			$ 39.99	$ 8.82	28.30%	3.94%
Distribution (kWh)	10,000	$ 0.0085	$ 85.00	10,000	$ 0.0121	$ 121.00	$ 36.0000	42.35%	11.93%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	10,000	-$ 0.0001	-$ 1.00	10,000	-$ 0.0036	-$ 36.00	$ (35.00)	3500.00%	-3.55%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 115.17**			**$ 124.99**	**$ 9.82**	**8.53%**	**12.32%**
Other Charges (kWh)	10565	$ 0.0222	$ 234.54	10565	$ 0.0178	$ 188.06	$ (46.49)	-19.82%	18.54%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	4.29%
Cost of Power Commodity (kWh)	9,815	$ 0.0670	$ 657.61	9,815	$ 0.0670	$ 657.61	$ -	0.00%	64.84%
Total Bill before Taxes			**$ 1,050.82**			**$ 1,014.15**	**$ (36.67)**	**-3.49%**	**100%**
GST (6%)			**$ 63.05**			**$ 60.85**	**$ (2.20)**	**-3.49%**	
Total Bill after Taxes			**$ 1,113.87**			**$ 1,075.00**	**$ (38.87)**	**-3.49%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service 50 to 4,999 kW

Consumption 5,000 kWh / 50 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 223.14	$ 70.32	46.01%	27.83%
Distribution (kWh)	5,000	$ -	$ -	5,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	50	$ 1.2099	$ 60.50	50	$ 2.2455	$ 112.28	$ 51.78	85.59%	14.00%
Regulatory Assets (kWh)	5,000	$ -	$ -	5,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	50	-$ 0.2732	-$ 13.66	50	-$ 1.3205	-$ 66.03	$ (52.37)	383.35%	-8.23%
Sub-Total			**$ 199.66**			**$ 269.39**	**$ 69.74**	**34.93%**	**33.60%**
Other Charges (kWh)	5283	$ 0.0132	$ 69.73	5283	$ 0.0121	$ 63.92	$ (5.81)	-8.33%	7.97%
Other Charges (kW)	53	$ 3.6186	$ 191.15	53	$ 2.2960	$ 121.29	$ (69.87)	-36.55%	15.13%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	5.43%
Cost of Power Commodity (kWh)	4,533	$ 0.0670	$ 303.68	4,533	$ 0.0670	$ 303.68	$ -	0.00%	37.88%
Total Bill before Taxes			**$ 807.71**			**$ 801.77**	**$ (5.94)**	**-0.74%**	**100%**
GST (6%)			**$ 48.46**			**$ 48.11**	**$ (0.36)**	**-0.74%**	
Total Bill after Taxes			**$ 856.18**			**$ 849.88**	**$ (6.30)**	**-0.74%**	

General Service 50 to 4,999 kW

Consumption 210 kWh / 65 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 223.14	$ 70.32	46.01%	49.40%
Distribution (kWh)	210	$ -	$ -	210	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	65	$ 1.2099	$ 78.64	65	$ 2.2455	$ 145.96	$ 67.31	85.59%	32.31%
Regulatory Assets (kWh)	210	$ -	$ -	210	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	65	-$ 0.2732	-$ 17.76	65	-$ 1.3205	-$ 85.83	$ (68.07)	383.35%	-19.00%
Sub-Total			**$ 213.71**			**$ 283.27**	**$ 69.56**	**32.55%**	**62.71%**
Other Charges (kWh)	222	$ 0.0132	$ 2.93	222	$ 0.0121	$ 2.68	$ (0.24)	-8.33%	0.59%
Other Charges (kW)	69	$ 3.6186	$ 248.50	69	$ 2.2960	$ 157.67	$ (90.83)	-36.55%	34.90%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	9.63%
Cost of Power Commodity (kWh)	-528	$ 0.0670	-$ 35.39	-528	$ 0.0670	-$ 35.39	$ -	0.00%	-7.83%
Total Bill before Taxes			**$ 473.25**			**$ 451.74**	**$ (21.51)**	**-4.55%**	**100%**
GST (6%)			**$ 28.39**			**$ 27.10**	**$ (1.29)**	**-4.55%**	
Total Bill after Taxes			**$ 501.64**			**$ 478.84**	**$ (22.80)**	**-4.55%**	

General Service 50 to 4,999 kW

Consumption 100,000 kWh / 500 kW ***Loss Factor 1.0565***

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 223.14	$ 70.32	46.01%	2.18%
Distribution (kWh)	100,000	$ -	$ -	100,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	500	$ 1.2099	$ 604.95	500	$ 2.2455	$ 1,122.75	$ 517.80	85.59%	10.96%
Regulatory Assets (kWh)	100,000	$ -	$ -	100,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	500	-$ 0.2732	-$ 136.60	500	-$ 1.3205	-$ 660.25	$ (523.65)	383.35%	-6.44%
Sub-Total			**$ 621.17**			**$ 685.64**	**$ 64.47**	**10.38%**	**6.69%**
Other Charges (kWh)	105650	$ 0.0132	$ 1,394.58	105650	$ 0.0121	$ 1,278.37	$ (116.22)	-8.33%	12.47%
Other Charges (kW)	528	$ 3.6186	$ 1,911.53	528	$ 2.2960	$ 1,212.86	$ (698.66)	-36.55%	11.83%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	0.42%
Cost of Power Commodity (kWh)	104,900	$ 0.0670	$ 7,028.30	104,900	$ 0.0670	$ 7,028.30	$ -	0.00%	68.58%
Total Bill before Taxes			**$ 10,999.08**			**$ 10,248.67**	**$ (750.41)**	**-6.82%**	**100%**
GST (6%)			**$ 659.94**			**$ 614.92**	**$ (45.02)**	**-6.82%**	
Total Bill after Taxes			**$ 11,659.02**			**$ 10,863.59**	**$ (795.43)**	**-6.82%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

General Service 50 to 4,999 kW

Consumption	400,000 kWh 500 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 152.82			$ 223.14	$ 70.32	46.01%	0.63%
Distribution (kWh)	400,000	$ -	$ -	400,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	500	$ 1.2099	$ 604.95	500	$ 2.2455	$ 1,122.75	$ 517.80	85.59%	3.18%
Regulatory Assets (kWh)	400,000	$ -	$ -	400,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	500	-$ 0.2732	-$ 136.60	500	-$ 1.3205	-$ 660.25	$ (523.65)	383.35%	-1.87%
Sub-Total			**$ 621.17**			**$ 685.64**	**$ 64.47**	**10.38%**	**1.94%**
Other Charges (kWh)	422600	$ 0.0132	$ 5,578.32	422600	$ 0.0121	$ 5,113.46	$ (464.86)	-8.33%	14.48%
Other Charges (kW)	528	$ 3.6186	$ 1,911.53	528	$ 2.2960	$ 1,212.86	$ (698.66)	-36.55%	3.43%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	0.12%
Cost of Power Commodity (kWh)	421,850	$ 0.0670	$ 28,263.95	421,850	$ 0.0670	$ 28,263.95	$ -	0.00%	80.02%
Total Bill before Taxes			**$ 36,418.47**			**$ 35,319.41**	**$ (1,099.05)**	**-3.02%**	**100%**
GST (6%)			**$ 2,185.11**			**$ 2,119.16**	**$ (65.94)**	**-3.02%**	
Total Bill after Taxes			**$ 38,603.57**			**$ 37,438.58**	**$ (1,165.00)**	**-3.02%**	

Unmetered Scattered Load

Consumption	100 kWh kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 19.61	$ 4.15	26.84%	68.88%
Distribution (kWh)	100	$ 0.0085	$ 0.85	100	$ 0.0121	$ 1.21	$ 0.3600	42.35%	4.25%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	100	-$ 0.0001	-$ 0.01	100	-$ 0.0036	-$ 0.36	$ (0.35)	3500.00%	-1.26%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 16.30**			**$ 20.46**	**$ 4.16**	**25.52%**	**71.87%**
Other Charges (kWh)	106	$ 0.0222	$ 2.35	106	$ 0.0178	$ 1.88	$ (0.46)	-19.82%	6.61%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	106	$ 0.0580	$ 6.13	106	$ 0.0580	$ 6.13	$ -	0.00%	21.52%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 24.77**			**$ 28.47**	**$ 3.70**	**14.92%**	**100%**
GST (6%)			**$ 1.49**			**$ 1.71**	**$ 0.22**	**14.92%**	
Total Bill after Taxes			**$ 26.26**			**$ 30.18**	**$ 3.92**	**14.92%**	

Unmetered Scattered Load

Consumption	200 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 19.61	$ 4.15	26.84%	52.54%
Distribution (kWh)	200	$ 0.0085	$ 1.70	200	$ 0.0121	$ 2.42	$ 0.7200	42.35%	6.48%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	200	-$ 0.0001	-$ 0.02	200	-$ 0.0036	-$ 0.72	$ (0.70)	3500.00%	-1.93%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 17.14**			**$ 21.31**	**$ 4.17**	**24.33%**	**57.09%**
Other Charges (kWh)	211	$ 0.0222	$ 4.69	211	$ 0.0178	$ 3.76	$ (0.93)	-19.82%	10.08%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	211	$ 0.0580	$ 12.26	211	$ 0.0580	$ 12.26	$ -	0.00%	32.83%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 34.09**			**$ 37.33**	**$ 3.24**	**9.51%**	**100%**
GST (6%)			**$ 2.05**			**$ 2.24**	**$ 0.19**	**9.51%**	
Total Bill after Taxes			**$ 36.13**			**$ 39.57**	**$ 3.43**	**9.51%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Unmetered Scattered Load

Consumption	1,000 kWh 0 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 15.46			$ 19.61	$ 4.15	26.84%	17.67%
Distribution (kWh)	1,000	$ 0.0085	$ 8.50	1,000	$ 0.0121	$ 12.10	$ 3.6000	42.35%	10.91%
Distribution (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kWh)	1,000	-$ 0.0001	-$ 0.10	1,000	-$ 0.0036	-$ 3.60	$ (3.50)	3500.00%	-3.24%
Regulatory Assets (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Sub-Total			**$ 23.86**			**$ 28.11**	**$ 4.25**	**17.81%**	**25.34%**
Other Charges (kWh)	1057	$ 0.0222	$ 23.45	1057	$ 0.0178	$ 18.81	$ (4.65)	-19.82%	16.95%
Other Charges (kW)	0	$ -	$ -	0	$ -	$ -	$ -	0.00%	0.00%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	39.21%
Cost of Power Commodity (kWh)	307	$ 0.0670	$ 20.54	307	$ 0.0670	$ 20.54	$ -	0.00%	18.51%
Total Bill before Taxes			**$ 111.35**			**$ 110.95**	**$ (0.40)**	**-0.36%**	**100%**
GST (6%)			**$ 6.68**			**$ 6.66**	**$ (0.02)**	**-0.36%**	
Total Bill after Taxes			**$ 118.03**			**$ 117.61**	**$ (0.42)**	**-0.36%**	

Sentinel Lighting

Consumption	222 kWh 0.6 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.33	$ 1.68	63.40%	17.27%
Distribution (kWh)	222	$ -	$ -	222	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	0.6	**$ 3.7484**	$ 2.25	0.6	$ 6.5934	$ 3.96	$ 1.71	75.90%	15.78%
Regulatory Assets (kWh)	222	$ -	$ -	222	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	0.6	$ 3.0482	$ 1.83	0.6	-$ 1.2956	-$ 0.78	$ (2.61)	-142.50%	-3.10%
Sub-Total			**$ 6.73**			**$ 7.51**	**$ 0.78**	**11.60%**	**29.95%**
Other Charges (kWh)	235	$ 0.0132	$ 3.10	235	$ 0.0121	$ 2.84	$ (0.26)	-8.33%	11.32%
Other Charges (kW)	1	$ 2.7987	$ 1.77	1	$ 1.7614	$ 1.12	$ (0.66)	-37.06%	4.45%
Cost of Power Commodity (kWh)	235	$ 0.0580	$ 13.60	235	$ 0.0580	$ 13.60	$ -	0.00%	54.27%
Cost of Power Commodity (kWh)	0	$ 0.0670	$ -	0	$ 0.0670	$ -	$ -	0.00%	0.00%
Total Bill before Taxes			**$ 25.20**			**$ 25.07**	**$ (0.13)**	**-0.53%**	**100%**
GST (6%)			**$ 1.51**			**$ 1.50**	**$ (0.01)**	**-0.53%**	
Total Bill after Taxes			**$ 26.71**			**$ 26.57**	**$ (0.14)**	**-0.53%**	

Sentinel Lighting

Consumption	865 kWh 2.3 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.33	$ 1.68	63.40%	5.02%
Distribution (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	2.3	**$ 3.7484**	$ 8.62	2.3	$ 6.5934	$ 15.16	$ 6.54	75.90%	17.57%
Regulatory Assets (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	2.3	$ 3.0482	$ 7.01	2.3	-$ 1.2956	-$ 2.98	$ (9.99)	-142.50%	-3.45%
Sub-Total			**$ 18.28**			**$ 16.51**	**-$ 1.77**	**-9.67%**	**19.13%**
Other Charges (kWh)	914	$ 0.0132	$ 12.06	914	$ 0.0121	$ 11.06	$ (1.01)	-8.33%	12.81%
Other Charges (kW)	2	$ 2.7987	$ 6.80	2	$ 1.7614	$ 4.28	$ (2.52)	-37.06%	4.96%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	50.39%
Cost of Power Commodity (kWh)	164	$ 0.0670	$ 10.98	164	$ 0.0670	$ 10.98	$ -	0.00%	12.72%
Total Bill before Taxes			**$ 91.63**			**$ 86.33**	**$ (5.29)**	**-5.78%**	**100%**
GST (6%)			**$ 5.50**			**$ 5.18**	**$ (0.32)**	**-5.78%**	

Total Bill after Taxes	**$ 97.12**		**$ 91.51**	**$ (5.61)**	**-5.78%**	

Chapleau Public Utilities Corporation

License Number: ED-2002-0528

Board File Number: EB-2006-0170
EDR File Number: EB-2005-0349
Cost Allocation File Number: EB-2007-0001

Sentinel Lighting

Consumption	2,000 kWh 5 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 2.65			$ 4.33	$ 1.68	63.40%	2.16%
Distribution (kWh)	2,000	$ -	$ -	2,000	$ -	$ -	$ -	0.00%	0.00%
Distribution (kWh)	5	**$ 3.7484**	$ 18.74	5	$ 6.5934	$ 32.97	$ 14.23	75.90%	16.44%
Regulatory Assets (kWh)	2,000	$ -	$ -	2,000	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	5	$ 3.0482	$ 15.24	5	-$ 1.2956	-$ 6.48	$ (21.72)	-142.50%	-3.23%
Sub-Total			**$ 36.63**			**$ 30.82**	**-$ 5.81**	**-15.87%**	**15.37%**
Other Charges (kWh)	2113	$ 0.0132	$ 27.89	2113	$ 0.0121	$ 25.57	$ (2.32)	-8.33%	12.75%
Other Charges (kW)	5	$ 2.7987	$ 14.78	5	$ 1.7614	$ 9.30	$ (5.48)	-37.06%	4.64%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	21.69%
Cost of Power Commodity (kWh)	1,363	$ 0.0670	$ 91.32	1,363	$ 0.0670	$ 91.32	$ -	0.00%	45.54%
Total Bill before Taxes			**$ 214.13**			**$ 200.51**	**$ (13.62)**	**-6.36%**	**100%**
GST (6%)			**$ 12.85**			**$ 12.03**	**$ (0.82)**	**-6.36%**	
Total Bill after Taxes			**$ 226.98**			**$ 212.54**	**$ (14.43)**	**-6.36%**	

Street Lighting

Consumption	865 kWh 2.3 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 0.80			$ 1.47	$ 0.67	83.75%	1.85%
Distribution (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	2	**$ 2.4286**	$ 5.59	2	$ 4.9518	$ 11.39	$ 5.80	103.90%	14.32%
Regulatory Assets (kWh)	865	$ -	$ -	865	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	2	$ 0.0178	$ 0.04	2	-$ 1.3551	-$ 3.12	$ (3.16)	-7712.92%	-3.92%
Sub-Total			**$ 6.43**			**$ 9.74**	**$ 3.32**	**51.59%**	**12.25%**
Other Charges (kWh)	914	$ 0.0132	$ 12.06	914	$ 0.0121	$ 11.06	$ (1.01)	-8.33%	13.91%
Other Charges (kW)	2	$ 2.7628	$ 6.71	2	$ 1.7443	$ 4.24	$ (2.47)	-36.86%	5.33%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	54.70%
Cost of Power Commodity (kWh)	164	$ 0.0670	$ 10.98	164	$ 0.0670	$ 10.98	$ -	0.00%	13.81%
Total Bill before Taxes			**$ 79.68**			**$ 79.52**	**$ (0.16)**	**-0.21%**	**100%**
GST (6%)			**$ 4.78**			**$ 4.77**	**$ (0.01)**	**-0.21%**	
Total Bill after Taxes			**$ 84.46**			**$ 84.29**	**$ (0.17)**	**-0.21%**	

Street Lighting

Consumption	24,500 kWh 65 kW	*Loss Factor 1.0565*

	2007 BILL			2008 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			$ 272.80			$ 501.27	$ 228.47	83.75%	17.31%
Distribution (kWh)	24,500	$ -	$ -	24,500	$ -	$ -	$ -	0.00%	0.00%
Distribution (kW)	65	**$ 2.4286**	$ 157.86	65	$ 4.9518	$ 321.87	$ 164.01	103.90%	11.12%
Regulatory Assets (kWh)	24,500	$ -	$ -	24,500	$ -	$ -	$ -	0.00%	0.00%
Regulatory Assets (kW)	65	$ 0.0178	$ 1.16	65	-$ 1.3551	-$ 88.08	$ (89.24)	-7712.92%	-3.04%
Sub-Total			**$ 431.82**			**$ 735.06**	**$ 303.24**	**70.22%**	**25.39%**
Other Charges (kWh)	25884	$ 0.0132	$ 341.67	25884	$ 0.0121	$ 313.20	$ (28.47)	-8.33%	10.82%
Other Charges (kW)	69	$ 2.7628	$ 189.73	69	$ 1.7443	$ 119.79	$ (69.94)	-36.86%	4.14%
Cost of Power Commodity (kWh)	750	$ 0.0580	$ 43.50	750	$ 0.0580	$ 43.50	$ -	0.00%	1.50%
Cost of Power Commodity (kWh)	25,134	$ 0.0670	$ 1,683.99	25,134	$ 0.0670	$ 1,683.99	$ -	0.00%	58.16%
Total Bill before Taxes			**$ 2,690.71**			**$ 2,895.54**	**$ 204.82**	**7.61%**	**100%**
GST (6%)			**$ 161.44**			**$ 173.73**	**$ 12.29**	**7.61%**	
Total Bill after Taxes			**$ 2,852.15**			**$ 3,069.27**	**$ 217.11**	**7.61%**	