EB-2008-0222
EB-2008-0223
EB-2008-0224

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

AND IN THE MATTER OF applications by Canadian Niagara Power Inc. – Eastern Ontario Power, Canadian Niagara Power Inc. – Fort Erie and Canadian Niagara Power Inc. – Port Colborne for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

Argument-In-Chief

of

Canadian Niagara Power Inc. – Fort Erie ("Fort Erie")

and

Canadian Niagara Power Inc. – Eastern Ontario Power ("EOP")

May 14, 2009

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1.0 INTRODUCTION

In accordance with Procedural Order No. 7, this Argument-in-Chief pertains to the distribution rate applications of Canadian Niagara Power Inc. - Fort Erie (EB-2008-0223) ("Fort Erie") and Canadian Niagara Power – Eastern Ontario Power Inc. (EB-2008-0222) ("EOP"). A separate Argument-in-Chief for Canadian Niagara Power Inc. – Port Colborne (EB-2008-0224) ("Port Colborne") will be filed at a later date in accordance with the Ontario Energy Board's (the "Board") directions.

This argument-in-chief summarizes the following major components of Fort Erie's and EOP's Applications:

- Rate Base;
- Operating Revenue;
- Operating Costs;
- Deferral and Variance Accounts;
- Cost of Capital;
- Rate Design; and
- Effective Date for Rates.

In order to provide context for major components summarized herein, the unique aspects of both Fort Erie and EOP are set out below.

Fort Erie's Unique Aspects

Fort Erie is a town with a population of 29,265 people and is located on the Niagara River in the southern Niagara region of Ontario. It is located directly across the river from Buffalo, New York and the two are connected by the Peace Bridge and the International Railway Bridge. In addition to Fort Erie proper, there are four additional core areas; Bridgeburg, Ridgeway, Stevensville and Crystal Beach that amalgamated in 1970 to form the current municipality of Fort Erie. CNPI - Fort Erie is contiguous with the service territory of CNPI – Port Colborne.

Fort Erie is located at the end of the Queen Elizabeth Way, the primary route for vehicular traffic from the greater Toronto area to New York State and Highway 3; a main route into the Niagara region and tourism areas.

The distribution system in Fort Erie began as a 25 cycle system fed directly from the Rankine Generating Station in Niagara Falls. It was not until 1958 that the conversion to a 60 cycle system was complete. Several of the distribution stations in service today predate this conversion.

Prior to Fortis' investment in CNPI, the development of the distribution system was influenced by American design methodologies. In fact, Fort Erie was never regulated by the former Ontario Hydro and its electrical load was considered to be in the New York control area.

The design influences of the previous American owner are most evident in the distribution voltages. The primary distribution system is comprised of a 34.5 kV, four wire multi-grounded neutral system and a 4.8 kV, three wire ungrounded delta system. While these distribution systems may be common in New York, they are rare or non-existent in Ontario. These factors introduce a number of challenges for CNPI – Fort Erie. The more dominant challenges include the following:

1. The ability to readily access replacement transformers. Because both the 34.5 kV and 4.8 kV Delta distribution systems are not common in Ontario, CNPI – Fort Erie must maintain an adequate inventory of spare distribution equipment, especially distribution transformers, to respond to system failures.

2. The 4.8 kV Delta distribution system has limited load carrying capability per feeder, and a greater number of substations and feeder egresses are required to service the customers. It is not feasible to service larger commercial and industrial customers from the 4.8 kV Delta system and overlapping of facilities does occur.

3. The 4.8 kV Delta system inherently will result in higher concentrations of elevated feeder currents to meet existing load requirements. This has contributed to distribution losses.

Following Fortis' initial investment, CNPI – Fort Erie undertook a distribution system review and began a systematic plan to control expansion of the 34.5 kV system, and to begin a conversion program to replace the 4.8 kV delta system in favour of a more standard 15 kV class distribution system.

This work combined with projects to strengthen the reliability and integrity continues throughout the forecast period of this Application. CNPI has made a significant capital investment in its distribution system. This has benefited ratepayers by maintaining a high level of reliability.

EOP's Unique Aspects

Gananoque is a town with a population of 5,285 people and is located in eastern Ontario on the north shore of the St. Lawrence River, approximately 20 kilometres east of Kingston. Gananoque is the entry point to the 1000 Islands. The service territory is 66 square kilometres and it is not contiguous with any other CNPI service territories. Gananoque is 145 kilometres southwest of Cornwall, Ontario.

EOP owns and operates the electricity distribution system in Gananoque, which serves approximately 3,600 customers, approximately 175 kilometers of overhead line, 20 kilometers of underground cables and 750 distribution transformers.

The electricity supply to EOP originates at the Hydro One 44 kV distribution system. The 44 kV Delta supply is stepped down to 26.4 kV Delta at EOP's Substation, which supplies the system's 26.4 kV Delta distribution system. The 26.4 kV system supplies larger industrial customers, six 26.4 kV-4.16Y/2.4 kV distribution substations, and also connects to five embedded hydro-electric generating plants.

The 26.4 kV and 4.16 kV distribution systems in Gananoque are generally of older vintage and some locations are in poor condition. EOP's capital programs in recent and future years have and will continue to focus on upgrading the system to replace aged components, increase capacity, and improve system reliability. The Town was originally supplied by the Thermal Plant Distribution Substation, which was supplied at 44 kV from Hydro One and distributed power at 26.4 kV Delta. This substation was aged beyond its useful life, in poor condition, and contained a single power transformer and a spare transformer of insufficient capacity to serve the Town's load. This placed the entire Town as "load at risk", therefore, a new Main Substation was constructed and commissioned in 2007 to replace the Thermal Plant Distribution Substation and enhance system reliability, capacity, and safety.

Capital investments in EOP will continue to focus on system upgrades and reliability. Substation investments in recent years have included the installation of oil containment systems, as none previously existed. These enhance the environmental, health, and safety aspects of the system.

CNPI has made a significant capital investment in its distribution system. This has benefited ratepayers by maintaining a high level of reliability. SAIDI and SAIFI indices in EOP have increased over a three-year period. A transitory experience of decreased reliability performance has been due to the deteriorating condition of the EOP distribution system, and also because of lengthy planned outages to the entire Town were required for construction and commissioning of the new Main Substation. These planned outages were necessary to make the capital investment required to improve reliability over the longer term. This illustrates the "sole source" nature of the electricity supply into EOP and highlights the need for the new Main Substation to serve the Town's load that was seriously at risk while supplied by the old Thermal Plant Substation.

In operating its distribution systems, CNPI's primary objectives are to optimize asset performance in a cost-effective manner to promote employee and public safety, maintain high standards of reliability, and meet customer demand. These are supported by prudent capital investments and implementing cost-effective solutions to ensuring high standards for safety and reliability.

Fort Erie Approvals Sought[1]

- The Proposed Return on Equity (Exhibit 6, Tab 1, Schedule 1)
- The Proposed Cost of Debt (Exhibit 6, Tab 1, Schedule 1)
- The Proposed Cost of Capital (Exhibit 6, Tab 1, Schedule 1)
- The Proposed Revenue Requirement in the amount of $9,827,418
- The Shared Services Allocation Methodology (Exhibit 4, Tab 2, Schedule 4)
- The Shared Assets Allocation Methodology (Exhibit 4, Tab 2, Schedule 4)
- The Proposed Customer Forecast (Exhibit 3, Tab 2, Schedule 1)
- The Proposed Normalized Load Forecast (Exhibit 3, Tab 2, Schedule 1)
- The Proposed Loss Factors (Exhibit 4, Tab 2, Schedule 8)
- The Proposed Tariff of Harmonized Rates and Charges Effective May 1, 2009 (Exhibit 1, Tab 1, Schedule 2, Appendix A, which are the preferred rates of the Applicant)
- In the alternative, and only in the event that the Board does not approve the proposed tariff in Appendix A, the Alternative Schedule of Rates and Charges (Exhibit 1, Tab 1, Schedule 2, Appendix B)
- A deferral account to track IFRS costs[2]
- Dispersal of deferral and variance accounts (Exhibit 5 Tab 1 Schedule 1 and Undertaking JT 2.20)

EOP Approvals Sought

- The Proposed Return on Equity (Exhibit 6, Tab 1, Schedule 1)
- The Proposed Cost of Debt (Exhibit 6, Tab 1, Schedule 1)
- The Proposed Cost of Capital (Exhibit 6, Tab 1, Schedule 1)

[1] As set out at Exhibit 1, Tab 1, Schedule 5.
[2] Please note that this request was not made in the Application. CNPI understands that the granting of a deferral account is in no way determinative of the dispersal of a deferral account.

- The Proposed Revenue Requirement in the amount of $2,359,739
- The Shared Services Allocation Methodology (Exhibit 4, Tab 2, Schedule 4)
- The Shared Assets Allocation Methodology (Exhibit 4, Tab 2, Schedule 4)
- The Proposed Customer Forecast (Exhibit 3, Tab 2, Schedule 1)
- The Proposed Normalized Load Forecast (Exhibit 3, Tab 2, Schedule 1)
- The Proposed Loss Factors (Exhibit 4, Tab 2, Schedule 8)
- The Proposed Elimination of the Previously Approved General Service 50 to 4,999 kW Time of Use Customer Class (Exhibit 9, Tab 1, Schedule 1)
- The Re-Classification of the Residual Two Customers of the Previously Approved General Service 50 to 4,999 kW Time of Use Customer Class to the General Service 50 to 4,999 kW Customer Class (Exhibit 9, Tab 1, Schedule 1)
- The Proposed Tariff of Harmonized Rates and Charges Effective May 1, 2009 (Exhibit 1, Tab 1, Schedule 2, Appendix A, which are the preferred rates of the Applicant)
- In the alternative, and only in the event that the Board does not approve the proposed tariff in Appendix A, the Alternative Schedule of Rates and Charges (Exhibit 1, Tab 1, Schedule 2, Appendix B)
- A deferral account to track IFRS costs [3]
- Dispersal of deferral and variance accounts (Exhibit 5 Tab 1 Schedule 1 and Undertaking JT 2.20)

[3] Please note that this request was not made in the Application. CNPI understands that the granting of a deferral account is in no way determinative of the dispersal of a deferral account.

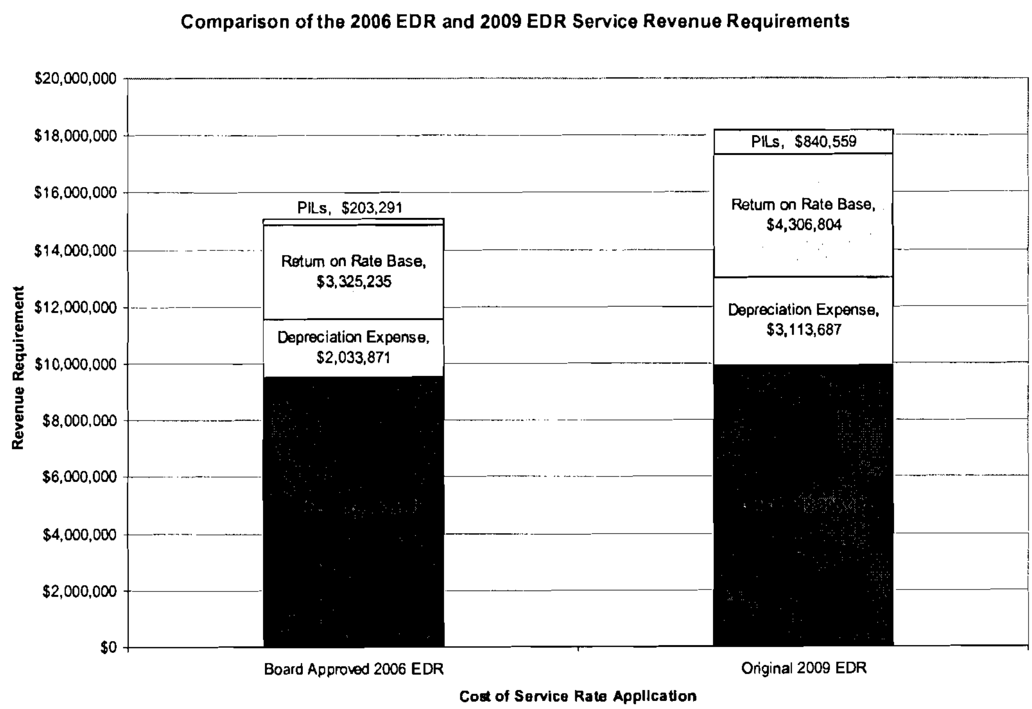
2.0 REVENUE REQUIREMENT

The 2009 Test Year revenue requirements proposed by Fort Erie and EOP were as follows:

- Fort Erie: $9,827,418 [4]
- EOP: $2,359,739 [5]

On a combined basis (Fort Erie, EOP and Port Colborne), CNPI has asked the Board to approve a 2009 service revenue requirement of $18.2 million. In the Board Approved 2006 EDR, the approved combined service revenue requirement was $15.1 million. The increase over the 2006 EDR is $3.1 million over five years or a 4% increase per annum. [6] Figure 2-1 below illustrates the components of both the 2006 Board Approved and 2009 proposed combined revenue requirement.

Figure 2-1



[4] Pre-filed Evidence of Fort Erie, Exhibit 1, Tab 2, Schedule 1, Page 1, Line 21
[5] Pre-filed Evidence of EOP, Exhibit 1, Tab 2, Schedule 1, Page 1, Line 21
[6] From the Supplementary Evidence filed April 20, 2009.

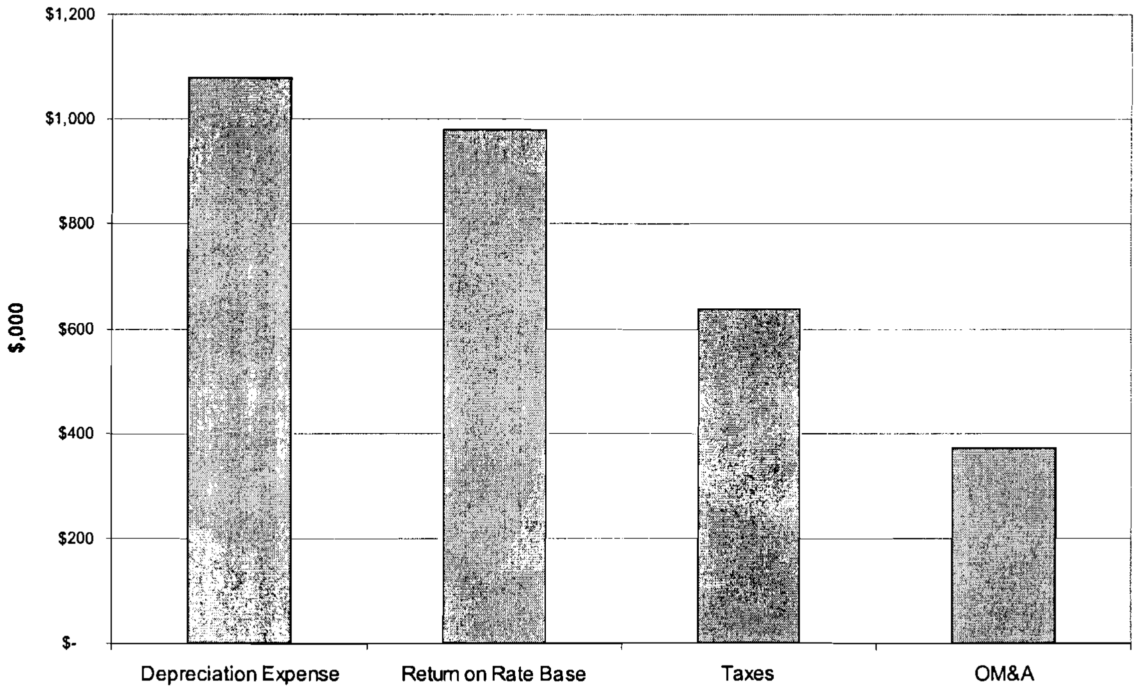
The increase in revenue requirement is primarily the result of the growth in rate base resulting in an increase in the return on rate base and depreciation expense, as illustrated by Table 2-1 below.

Table 2-1 Components of the Service Revenue Requirement						
Component	2006 Board Approved		2009 Test Year		Contribution to Change	
	$,000	%	$,000	%	$,000	%
Depreciation Expense	2,034	14%	3,114	17%	1,080	35%
Return on Rate Base	3,325	22%	4,307	24%	982	32%
Taxes	204	1%	841	5%	637	21%
OM&A	9,524	63%	9,896	54%	372	12%
Total	**15,087**	**100%**	**18,158**	**100%**	**3,071**	**100%**

The following Figure 2-2 provides a graphical representation of each component's contribution to the change in service revenue requirement from the 2006 Board Approved to the 2009 Test Year.

Figure 2-2

Contributions to Change in Service Revenue Requirement



With depreciation expense and return on rate base comprising 67% of the increase in revenue requirement from the Board Approved 2006 EDR to the 2009 Test Year, it is evident that the increase is being driven by capital expenditures. As indicated in Section 3 below, capital expenditures from 2006 to 2009 remain relatively constant. However, because rate base is cumulative, rate base is increasing from year-to-year even though capital expenditure levels remain relatively constant.

3.0 RATE BASE

Fort Erie

As indicated in the table below, Fort Erie's rate base for 2009 has been forecasted to be $37,463,907, being the average net book value of fixed assets and an allowance for working capital. [7]

Table 3-1 - Summary of Rate Base (Fort Erie)

RATE BASE VARIANCE TABLE

Description	2006 Board Approved	2006 Actual	Variance from 2006 EDR	2007 Actual	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual	2009 Test Year	Variance from 2008 Bridge
Gross Fixed Assets	43,184,574	48,307,498	5,122,924	51,804,941	3,497,443	54,228,185	2,423,243	57,322,392	3,094,208
Accumulated Depreciation	(14,785,883)	(17,487,594)	(2,701,711)	(19,241,156)	(1,753,562)	(21,149,545)	(1,908,389)	(23,162,983)	(2,013,438)
Net Book Value	28,398,691	30,819,904	2,421,213	32,563,786	1,743,882	33,078,640	514,854	34,159,409	1,080,770
Average Net Book Value	26,432,452	31,779,353	5,346,901	31,691,845	(87,508)	32,821,213	1,129,368	33,619,024	797,812
Working Capital Allowance	3,725,494	3,957,040	231,546	4,039,627	82,587	3,796,639	(242,987)	3,844,883	48,244
Rate Base	30,157,946	35,736,393	5,578,447	35,731,471	(4,921)	36,617,852	886,381	37,463,907	846,055

Fort Erie's gross capital expenditures can be summarized as follows:

Table 3-2 – Summary of Gross Capital Expenditures (Fort Erie)[8]

2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
$3,949,000	$4,501,000	$4,139,000	$4,110,000

CNPI's comprehensive asset management practices are set out in its response to Board Staff interrogatory #3. Descriptions of specific capital projects that exceed materiality are set out at Exhibit 2, Tab 3, Schedule 1, Appendix A.

[7] Reproduced from Exhibit 2, Tab 1, Schedule 2, Page 1.
[8] Reproduced from Exhibit TC1 from the February 18, 2009 Technical Conference and the response to Board Staff interrogatory #2. Smart Meter spending not included.

As illustrated by Table 3-2 above, annual gross capital expenditures from 2006 to 2009 remain relatively constant, with the exception of an increase in 2007 that was attributable to critical system improvements that, left unaddressed, could have potentially affected safety or reliability. As explained at Exhibit 2, Tab 3, Schedule 1, Appendix A, Page 7, some of these issues occurred during the October 2006 natural disaster, for example, the replacement of a number of broken poles that had been temporarily repaired during the storm.

The average of the capital expenditures from 2006 to 2008 is $4,196,333. The forecasted capital expenditures for the 2009 Test Year is approximately $86,000 lower than the average of the preceding three years.

EOP

As indicated in the table below, Fort Erie's rate base for 2009 has been forecasted to be $7,756,830 being the average net book value of fixed assets and an allowance for working capital.

Table 3-3 - Summary of Rate Base (EOP)

RATE BASE VARIANCE TABLE

Description	2006 Board Approved	2006 Actual	Variance from 2006 EDR	2007 Actual	Variance from 2006 Actual	2008 Bridge Year	Variance from 2007 Actual	2009 Test Year	Variance from 2008 Bridge
Gross Fixed Assets	5,562,689	8,187,821	2,625,132	11,020,904	2,833,083	11,992,921	972,017	12,822,582	829,661
Gross Write Up[(1)]		(1,400,000)		(1,400,000)		(1,400,000)		(1,400,000)	
Accumulated Depreciation Write Up[(1)]		159,415		201,925		244,436		286,946	
Accumulated Depreciation	(2,800,427)	(3,308,735)	(508,308)	(3,672,203)	(363,468)	(4,125,133)	(452,930)	(4,605,671)	(480,538)
Net Book Value	2,762,262	3,638,501	876,238	6,150,626	2,512,125	6,712,224	561,598	7,103,857	391,633
Average Net Book Value	2,562,599	4,158,377	1,595,778	4,894,564	736,187	6,431,425	1,536,862	6,908,041	476,615
Working Capital Allowance	1,105,943	1,076,526	(29,417)	952,468	(124,059)	918,755	(33,713)	848,789	(69,966)
Rate Base	3,668,542	5,234,903	1,566,362	5,847,031	612,128	7,350,180	1,503,149	7,756,830	406,649

(1) Gross fixed assets revalued upon acquisition by CNPI in 2003 and 'written up' to FMV. 'Write up' excluded from Rate Base for ratemaking purposes.

Table 3-4 – Summary of Gross Capital Expenditures (EOP)[9]

2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
$264,000	$2,798,000	$967,000	$868,000

Descriptions of specific EOP capital projects that exceed materiality are set out at Exhibit 2, Tab 3, Schedule 1, Appendix A.

As illustrated by Table 3-4 above, the level of capital expenditures in 2006 was significantly lower than in 2007. This variance is primarily attributable to the new outdoor Main 44 kV – 26.4 kV Substation that was constructed during 2006 and 2007, but was capitalized in 2007 when it became used and useful (ie. the amounts contained in Table 2-4 above reflect capitalized amounts, not spent amounts). As set out at Exhibit 2, Tab 3, Schedule 1, Appendix A, Page 5, this substation replaced the aging, deteriorated Thermal Plant Substation that was the sole supply point into the Town of Gananoque. This Substation contained a single 20 MVA power transformer with a spare 10 MVA unit located outside the substation fence. Apart from the in-service power transformer, the equipment at the substation was in poor condition, operating at a high risk of equipment failure. The old substation was constructed so that working clearances around equipment were limited, giving rise to safety hazards should work be attempted around live components. Thus, maintaining components at the existing substation would require equipment outages, and due to the lack of capacity, required extended customer outages. Due to the critical nature of this substation being the sole electrical energy source to the Town, it was concluded that the system load was at serious risk if it continued to be served from this facility. Therefore, the decision was made to construct the new Main Substation to replace the existing Thermal Plant Substation.

[9] Reproduced from Exhibit TC1 from the February 18, 2009 Technical Conference and the response to Board Staff interrogatory #2. Smart Meter spending not included.

With the exception of the 2006-2007 variance in capital expenditures described above, forecasted capital expenditures in 2008 and 2009 are relatively consistent, with the 2009 amount being approximately $100,000 less than 2008.

4.0 OPERATING REVENUE

Fort Erie

Table 4-1 – Numerical Summary of Operating Revenue (Fort Erie)

The following tables provide a summary of CNPI – Fort Erie's actual, normalized actual and forecasted throughput volumes for the 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year:[10]

CNPI - Fort Erie Volumes (kwh)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	112,747,739	111,959,084	113,155,501	114,221,401	113,372,453	114,347,232	115,322,011
General Service Less Than 50 kW	42,674,415	37,929,541	38,334,864	37,580,115	37,300,802	37,523,969	37,747,136
General Service 50 to 4,999 kW	145,569,210	133,812,631	134,317,403	142,072,764	141,700,013	144,714,906	147,729,800
Unmetered Scattered Load	318,026	331,402	331,402	335,072	335,072	340,950	349,768
Sentinel Lighting	863,072	786,169	786,169	797,374	797,374	797,374	797,374
Street Lighting	2,339,029	2,522,307	2,522,307	2,189,412	2,189,412	2,200,127	2,210,842
Total	304,511,490	287,341,134	289,447,646	297,196,138	295,695,125	299,924,558	304,156,931

CNPI - Fort Erie Throughput Revenue ($)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	$4,043,487	$3,968,579	$3,968,579	$4,078,004	$4,078,004	$4,172,611	$4,798,423
General Service Less Than 50 kW	1,179,542	1,082,653	1,082,653	1,081,177	1,081,177	1,074,028	1,202,141
General Service 50 to 4,999 kW	2,742,200	2,599,933	2,599,933	2,848,982	2,848,982	3,017,208	2,898,066
Unmetered Scattered Load	17,861	-	-	5,736	5,736	19,328	23,992
Sentinel Lighting	25,050	11,653	11,653	9,673	9,673	27,444	42,280
Street Lighting	57,530	22,367	22,367	29,801	29,801	58,739	88,726
Total	$8,065,671	$7,685,185	$7,685,185	$8,053,372	$8,053,372	$8,369,358	$9,053,628

CNPI - Fort Erie Revenue Per kwh ($)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	0.0359	0.0354	0.0351	0.0357	0.0360	0.0365	0.0416
General Service Less Than 50 kW	0.0276	0.0285	0.0282	0.0288	0.0290	0.0286	0.0318
General Service 50 to 4,999 kW	0.0188	0.0194	0.0194	0.0201	0.0201	0.0208	0.0196
Unmetered Scattered Load	0.0562	-	-	0.0171	0.0171	0.0567	0.0686
Sentinel Lighting	0.0290	0.0148	0.0148	0.0121	0.0121	0.0344	0.0530
Street Lighting	0.0246	0.0089	0.0089	0.0136	0.0136	0.0267	0.0401
Total	0.0265	0.0267	0.0266	0.0271	0.0272	0.0279	0.0298

Exhibit 3, Tab 1, provides an overview of 2006 Board Approved operating revenue, 2006 Actual and 2006 normalized revenues, 2007 Actual and 2007 normalized revenues, 2008

[10] Reproduced from Exhibit 3, Tab 1, Schedule 2, Page 1 (Fort Erie pre-filed evidence).

Bridge Year normalized forecast and 2009 Test Year normalized forecast for operating revenues based on the most recently approved distribution rates for the applicable period.

2008 Bridge Year is based on rates approved in Fort Erie's IRM EB-2007-0839. Test Year revenue is forecasted with proposed distribution rates.

Fort Erie has included an overview of the community it serves and individual customer class analysis. Fort Erie's weather normalization methodology is explained and applied to historical actuals to allow for forecasting normalized throughputs in the Bridge Year and Test Year.

Exhibit 3, Tab 2, Appendix A, is a copy of CNPI – Fort Erie's Customer, Load and Demand Forecast. An electronic copy accompanied the Application.

Exhibit 3, Tab 3, provides an overview of Other Revenue.

EOP

The following tables provide a summary of EOP's actual, normalized actual and forecasted throughput volumes for 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Bridge Year and 2009 Test Year:[11]

[11] Reproduced from Exhibit 3, Tab 1, Schedule 2, Page 1 (EOP pre-filed evidence).

Table 4-2 – Numerical Summary of Operating Revenue (EOP)

CNPI - Gananoque Volumes (kwh)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	28,793,211	29,533,620	29,870,163	29,640,947	29,406,023	29,491,395	29,586,254
General Service Less Than 50 kW	14,364,062	14,139,203	14,300,323	13,888,581	13,778,505	13,913,258	14,048,011
General Service 50 to 4,999 kW	14,288,206	13,878,467	13,919,428	13,693,566	13,665,457	14,106,278	14,547,099
General Service 50 to 4,999 kW Time of Use	28,219,111	17,033,453	17,066,540	8,145,825	8,134,854	7,017,128	4,067,428
Unmetered Scattered Load	-	92,013	92,013	94,602	94,602	94,602	94,602
Sentinel Lighting	17,803	76,668	76,668	76,188	76,188	78,846	80,618
Street Lighting	132,685	644,646	644,646	546,343	546,343	550,981	555,619
Total	85,815,078	75,398,070	75,969,781	66,086,052	65,701,972	65,252,488	62,979,630

CNPI - Gananoque Throughput Revenue ($)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	$751,707	$795,961	$795,961	$782,287	$782,287	$810,834	$1,095,887
General Service Less Than 50 kW	355,718	382,572	382,572	376,093	376,093	374,113	382,111
General Service 50 to 4,999 kW	347,212	462,401	462,401	458,895	458,895	450,116	680,539
General Service 50 to 4,999 kW Time of Use	276,650	214,511	214,511	166,268	166,268	176,568	-
Unmetered Scattered Load	-	-	-	1,355	1,355	4,600	4,720
Sentinel Lighting	1,458	2,752	2,752	2,524	2,524	2,473	4,500
Street Lighting	12,516	17,899	17,899	19,331	19,331	16,495	27,529
Total	$1,745,260	$1,876,096	$1,876,096	$1,806,754	$1,806,754	$1,835,199	$2,195,286

CNPI - Gananoque Revenue Per kwh ($)

Customer Class	2006 Board Approved	2006 Actual	2006 Normalized Actual	2007 Actual	2007 Normalized Actual	2008 Bridge Year Normalized	2009 Test Year Normalized
Residential	0.0261	0.0270	0.0266	0.0264	0.0266	0.0275	0.0370
General Service Less Than 50 kW	0.0248	0.0271	0.0268	0.0271	0.0273	0.0269	0.0272
General Service 50 to 4,999 kW	0.0243	0.0333	0.0332	0.0335	0.0336	0.0319	0.0468
General Service 50 to 4,999 kW Time of Use	0.0098	0.0126	0.0126	0.0204	0.0204	0.0252	-
Unmetered Scattered Load	-	-	-	-	-	0.0486	0.0499
Sentinel Lighting	0.0819	0.0359	0.0359	0.0331	0.0331	0.0314	0.0558
Street Lighting	0.0943	0.0278	0.0278	0.0354	0.0354	0.0299	0.0495
Total	0.0203	0.0249	0.0247	0.0273	0.0275	0.0281	0.0349

Exhibit 3, Tab 1, provides an overview of 2006 Board Approved operating revenue, 2006 Actual and 2006 normalized revenues, 2007 Actual and 2007 normalized revenues, the 2008 Bridge Year normalized forecast and 2009 Test Year normalized forecast for operating revenues based on the most recently approved distribution rates for the applicable period.

2008 Bridge Year is based on rates approved in EOP's IRM EB- 2007-0846. Test Year revenue is forecasted with proposed distribution rates.

Exhibit 3, Tab 2, is EOP's customer forecast and throughput forecasts for Bridge and Test years. This Exhibit provides an accounting of customer, energy and demand from the 2006 Board Approved through to 2009 Test Year. EOP has included an overview of the community it serves and individual customer class analysis.

EOP's weather normalization methodology is explained and applied to historical actuals to allow for forecasting normalized throughputs in Bridge Year and Test Year.

Exhibit 3, Tab 2, Appendix A, is a copy of EOP's Customer, Load and Demand Forecast, an electronic copy accompanied the Application.

Exhibit 3, Tab 3, provides an overview of Other Revenue.

5.0 OPERATING COSTS

CNPI strives to minimize operating costs, while maintaining a high level of service quality, reliability and customer/employee safety.

Overview of Fort Erie's Operating Costs

Fort Erie's operating costs include: OM&A, capital and property taxes. A summary of Fort Erie's operating costs is set out in the following table:[12]

Table 5-1 – Numerical Summary of OM&A Costs (Fort Erie)

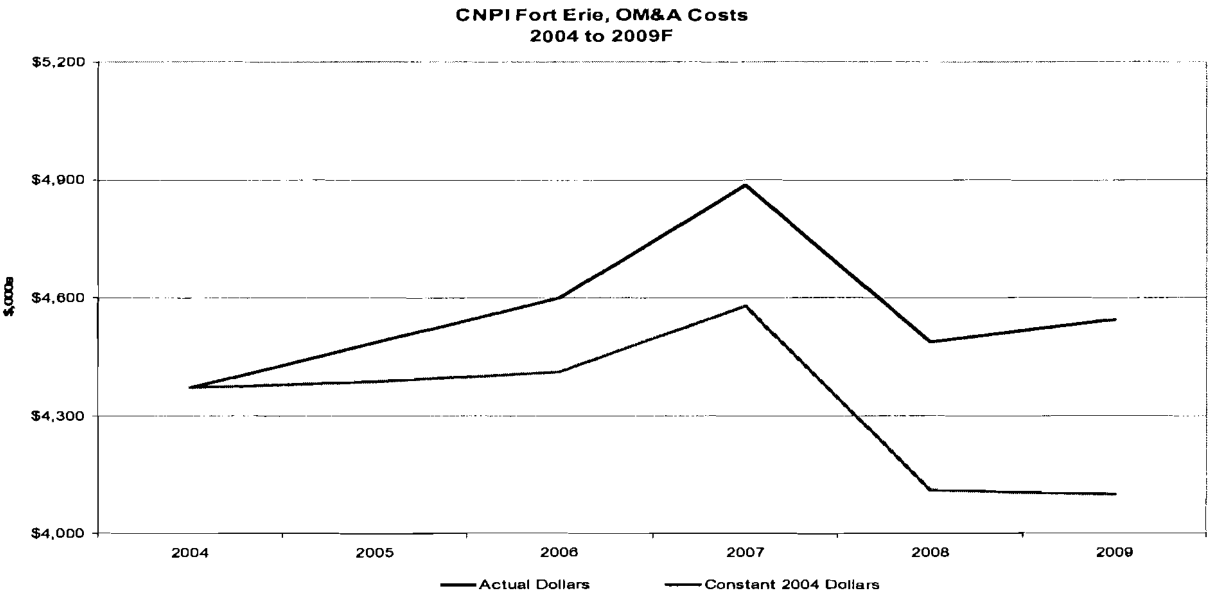
Total Operations, Maintenance, and Administrative Expenses					
Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Operating	714,745	1,356,505	914,403	791,762	841,410
Maintenance	934,204	686,312	1,021,025	1,015,734	1,013,416
Billing and Collection	796,730	1,034,116	1,019,329	1,021,251	946,160
Community Relations	4,234	2,661	6,788	14,500	43,830
Administrative and General	1,869,376	1,464,801	1,872,730	1,588,543	1,645,174
Taxes Other Than Income Taxes	50,189	56,032	50,617	55,000	54,000
	4,369,478	4,600,427	4,884,893	4,486,789	4,543,990

As illustrated by Table 5-1 above, Fort Erie's total operating costs have remained stable from 2004 (2006 Board Approved) to 2009. The annual average total operating costs from 2006 Board Approved to the 2008 Bridge Year is $4,585,397. The total operating costs proposed for the 2009 Test Year are slightly lower than this average. Therefore, relative to past years' operating costs, the proposed operating costs for the 2009 Test Year are reasonable.

[12] Reproduced from Exhibit 4, Tab 1, Schedule 1, Page 1 (Fort Erie pre-filed evidence).

As illustrated by the following figure,[13] although the 2009 Test Year OM&A cost on an actual dollar basis is slightly higher than the 2006 EDR level (approximately $175,000), on a constant dollar basis[14] Fort Erie's proposed OM&A for the 2009 Test Year is lower than the 2006 EDR level. Adjusting for inflation, the proposed OM&A for the 2009 Test Year is $4,099,315 or approximately $270,000 (6%) less than the 2006 EDR level.

Figure 5-1 – OM&A in Actual and Constant Dollars (Fort Erie)



The increase in OM&A in 2007 was attributable to CNPI's early retirement program, described in the pre-filed evidence,[15] whereby in 2007 CNPI carried out a voluntary early retirement window (the "2007 ERW") and 12 employees from CNPI elected to take early retirement effective December 31, 2007. The purpose of this program was to enable and support sound and responsible human resources management as part of CNPI's ongoing efforts to improve overall performance in the face of growing regulatory and industry challenges. The resulting decline in costs for 2008 is a result of this initiative along with other cost savings initiatives. Because the cost of the 2007 ERW was not incorporated in

[13] Reproduced from Supplementary Evidence dated April 20, 2009.
[14] Constant 2004 dollars adjust for the impact of inflation since 2004.
[15] Exhibit 4, Tab 2, Schedule 5, Appendix B, Page 2.

CNPI's distribution rates, these costs were borne by CNPI's shareholder. CNPI is not seeking recovery of these costs in this Application.

Overview of EOP's Operating Costs

EOP's operating costs include: OM&A, capital and property taxes. A summary EOP's operating costs is set out in the following table:[16]

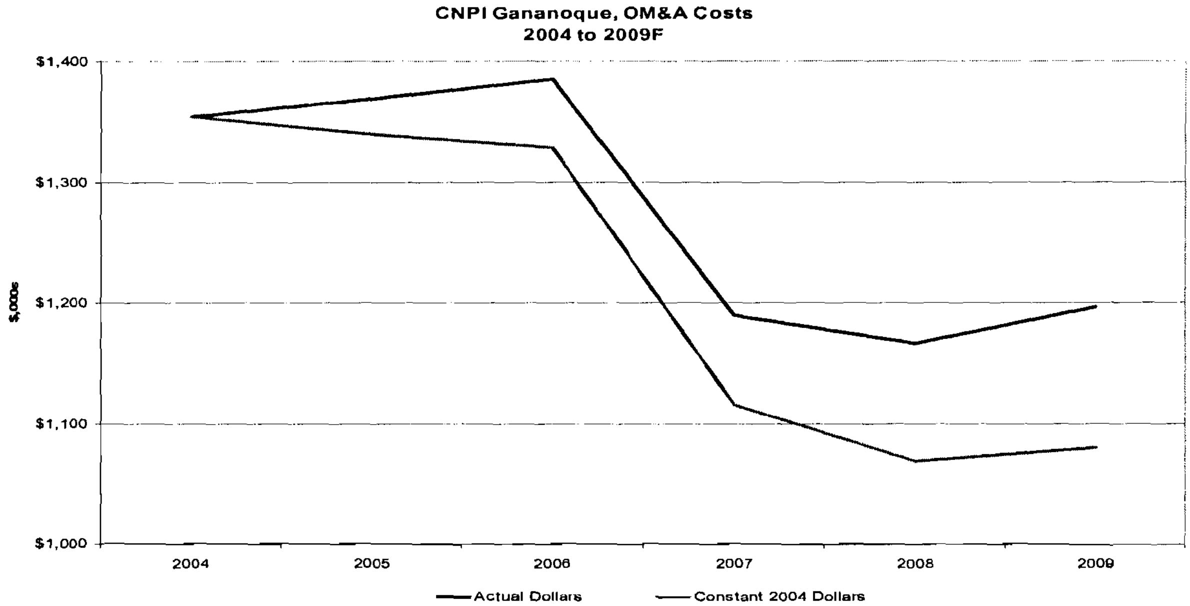
Table 5-2

Total Operations, Maintenance, and Administrative Expenses					
Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Bridge Year	2009 Test Year
Operating	257,502	286,543	211,361	234,418	250,755
Maintenance	173,348	155,026	192,808	242,150	205,570
Billing and Collection	310,698	286,279	267,986	258,419	269,081
Community Relations	2,168	-	951	2,450	4,000
Administrative and General	575,355	656,664	514,893	424,408	462,469
Taxes Other Than Income Taxes	21,215	603	2,213	5,000	5,000
	1,340,286	1,385,115	1,190,212	1,166,845	1,196,875

EOP's proposed total operating cost for the 2009 Test Year is 11% lower than the 2006 Board Approved level, and 6% lower than the average from 2006 Board Approved to the 2008 Bridge Year. As illustrated by the following figure,[17] on a constant dollar basis[18] EOP's proposed OM&A for the 2009 Test Year is 19% lower than the 2006 EDR level. Adjusting for inflation, the proposed OM&A for the 2009 Test Year is $1,079,749 or approximately $261,000 less than the 2006 EDR level.

[16] Reproduced from Exhibit 4, Tab 1, Schedule 1, Page 1 (EOP pre-filed evidence).
[17] Reproduced from Supplementary Evidence dated April 20, 2009.
[18] Constant 2004 dollars adjust for the impact of inflation since 2004.

Figure 5-2



Shared Services and Allocation of Costs

Within CNPI, management and specialist staff, and certain key systems and facilities, are shared to maximize efficiencies, avoid duplication, and provide the required skills and expertise to each business function. The sharing of services and assets pursuant to services agreements reduces the costs to customers by providing economies of scale. CNPI retained BDR NorthAmerica Inc. ("BDR") to review the methodology and computations used for the allocation of shared costs, based on BDR's extensive experience in cost allocation for energy utilities. This report (the "BDR Report") is attached as Appendix B to Exhibit 4, Tab 2, Schedule 4. The BDR Report confirms BDR's opinion as to the reasonableness of the overall approach by CNPI and the specific allocation of each cost function in this Application.

6.0 DEFERRAL AND VARIANCE ACCOUNTS

In the pre-filed evidence for both Fort Erie and EOP,[19] CNPI sought to dispose of Account 1508 – Other Regulatory Assets. CNPI's request was based on the understanding that the Board had initiated a review of the disposal of the RCVA and RSVA accounts. Therefore, CNPI deferred requesting disposal of these accounts until the Board's review was completed, at which time CNPI would apply for recovery.

The determination of rate riders associated with the disposition of Account 1508 – Other Regulatory Assets is found in the pre-filed evidence.[20] These Regulatory Rate Riders are included in the Proposed Schedule of Rates and Charges, Exhibit 1 Tab 1 Schedule 2 Appendix A, and are described as Regulatory Asset Recovery.

During the Oral Hearing in this matter, Board Staff requested in Undertaking No. JT 2.2 that CNPI provide the quantum and impact on rates if other deferral and variance accounts were disposed. CNPI responded to that Undertaking on April 30, 2009. In its response, CNPI calculated and provided to the Board the Regulatory Asset Rate Riders and associated billing determinants for the disposition of:

- Account 1580 – RSVA - Wholesale Market Service Charge
- Account 1582 – RSVA - One-time Wholesale Market Service Charge
- Account 1584 – RSVA - Retail Transmission Network Service Charge
- Account 1586 – RSVA - Retail Transmission Connection Service Charge
- Account 1588 – RSVA – Power
- Account 1508 – Other Regulatory Assets

CNPI would be amenable to the Board dispersing these accounts as part of this proceeding. The Regulatory Asset Recovery Rate Rider associated with this request has not yet been included in CNPI's Proposed Schedule of Rates and Charges at Appendix "A" of this Argument-in-Chief. CNPI will comply with Board direction in this matter.

[19] Exhibit 5 Tab 1 Schedule 1 for both Fort Erie and EOP
[20] Exhibit 5 Tab 1 Schedule 4 for both Fort Erie and EOP

7.0 COST OF CAPITAL

Capital Structure

Both Fort Erie and EOP's current OEB-approved deemed capital for rate making purposes is 53.3% debt and 46.7% equity. Fort Erie and EOP proposed a 2009 Test Year deemed capital structure for rate making purposes of 56.7% debt and 43.3% equity. This deemed capital structure was determined by the OEB in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 (the "Board Report"). The 56.7% debt component is comprised of 4% deemed short term debt and 52.7% deemed long term debt.

Table 7-1 – Deemed Capital Structure (Fort Erie) [21]

	2006 Board Approved		2006 Actual		2007 Actual		2008 Bridge Year		2009 Test Year	
Long-term debt	15,079	50%	17,868	50%	17,866	50%	19,517	53.3%	19,744	52.7%
Short-term debt	0	0%	0	0%	0	0%	0	0%	1,499	4.0%
Total debt	15,079	50%	17,868	50%	17,866	50%	19,517	53.3%	21,242	56.7%
Common equity	15,079	50%	17,868	50%	17,866	50%	17,101	46.7%	16,222	43.3%
Total	**30,158**	**100%**	**35,736**	**100%**	**35,731**	**100%**	**36,618**	**100%**	**37,464**	**100%**

[21] Reproduced from Exhibit 6, Tab 1, Schedule 1, Page 1 (Fort Erie pre-filed evidence).

Table 7-2 - Deemed Capital Structure (EOP) [22]

	2006 Board Approved		2006 Actual		2007 Actual		2008 Bridge Year		2009 Test Year	
Long-term debt	1,835	50%	2,618	50%	2,924	50%	3,918	53.3%	4,088	52.7%
Short-term debt	0	0%	0	0%	0	0%	0	0%	310	4.0%
Total debt	1,835	50%	2,618	50%	2,924	50%	3,918	53.3%	4,398	56.7%
Common equity	1,835	50%	2,618	50%	2,924	50%	3,432	46.7%	3,359	43.3%
Total	3,669	100%	5,235	100%	5,847	100%	7,350	100%	7,757	100%

Cost of Debt

CNPI currently has outstanding a $15 million demand promissory note payable to FortisOntario. The company is forecasting an additional $6 million of affiliated borrowing in 2009. Therefore, the total affiliated debt before the end of 2009 is forecast to be $21 million, as set out at Exhibit 6 Tab 1 Schedule 1 of the pre-filed evidence. Since the $21 million debt will be "affiliate debt that is callable on demand" as described in the Board Report, CNPI submits that the appropriate deemed long-term debt rate to apply would be 7.62% as established by the Board's *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* dated February 24, 2009.

In addition, CNPI has embedded third party long term debt of $30 million. The senior unsecured notes were issued on August 14, 2003 and bear interest of 7.092% and are payable at maturity on August 14, 2018. This is discussed fully in the pre-filed evidence Exhibit 6 Tab 1 Schedule 1.

[22] Reproduced from Exhibit 6, Tab 1, Schedule 1, Page 1 (EOP pre-filed evidence).

Cost of Equity

For both Fort Erie and EOP, CNPI is requesting a return on equity ("ROE") of 8.01% in the 2009 Test Year in accordance with the Board's *Cost of Capital Parameter Updates for 2009 Cost of Service Applications* dated February 24, 2009.

8.0 RATE DESIGN

CNPI has provided a sound and well balanced rate design methodology. CNPI employed a methodology respecting Board guidelines related to total bill impact and cost allocation while maintaining a sense of fairness amongst the customer classes.

Elimination of the General Service greater than 50 kW to 4,999 kW Time-of-Use

In the Board's Decision and Order in EOP's rate application for rates effective May 1, 2007, (EB-2007-0594), the Board ordered as follows:

> *CNPI – Eastern Ontario Power shall file a revised rate design proposal that eliminates the temporarily approved General Service > 50kW TOU class as part of its next cost of service application.*

In its rate design, EOP has proposed the elimination of this class by combining the remaining two customers of that class with the customers of the General Service 50 to 4,999 kW class. The entirety of the combine customers now in the General Service greater than 50 kW to 4,999 kW are homogenous as to the description of that class.

Harmonization

In its Applications, CNPI has proposed to harmonize the distribution rates of the Fort Erie and EOP service territories. The Port Colborne service territory has been intentionally omitted from the harmonization in the Applications due to restrictions related to the lease agreement with Port Colborne Hydro Inc. and the Board's approval of that lease.

Currently, CNPI operates three distribution territories, Fort Erie, Port Colborne and EOP, as well as a transmission operation. CNPI operates primarily from a single location, Fort Erie, with a single work force and allocates assets and services to each of these business units. This segregation of business units requires duplicated efforts related to financial and regulatory reporting, regulatory compliance and rate setting. CNPI proposes, with these Applications, to begin a process to harmonize its distribution operations as a single entity thus eliminating this duplication and reduce regulatory burdens for CNPI and the Regulator.

The approach taken in this electricity distribution rate harmonization proposal is to blend the two revenue requirements that had been developed separately, both in the Fort Erie Application, EB-2008-0223 and the EOP Application, EB-2008-0222 and combine them as one. While this approach will inevitably result in some revenue shifting between the two service territories, CNPI has considered this variable in its rate design, Exhibit 10, Tab 1, Schedule 3.

Any incremental rate impacts of this design are minimal as illustrated in CNPI's response to the Oral Hearing Undertaking JT2.4.

Customer Forecast

Fort Erie and EOP have experienced modest growth over the historical period from 2004 and as such CNPI has projected this modest growth into the Test Year. In addition, EOP has experienced contraction in the General Service greater than 50 kW (previously described as General Service greater than 50 kW to 4,999 kW Time-of-Use) as a result of business closures. This has been discussed thoroughly in the EOP pre-filed evidence Exhibit 3 Tab 2 Schedule 1.

Weather Normalization

CNPI used a combination of weather normalization work completed by Hydro One Networks for CNPI and other LDCs in preparation for the 2006 Cost Allocation Informational Filing and more current weather normalization data resources in the Ontario Demand Forecast produced by the IESO. Hydro One Networks had determined the relative percentages of distribution system loads that are sensitive and non-sensitive to influence of weather. The IESO had developed a measure of the effect of weather on the Ontario loads. CNPI combined the two factors to proxy the impact of weather on the historical loads and develop weather adjusted forecast.

The findings are discussed thoroughly in pre-filed evidence Exhibit 3 Tab 2 Schedule 1 and again in the Oral Hearing, Transcript EB-2008-0222-0223-0224,April20Vol1.

CNPI correlated the results of its weather normalization methodology with the degree days experienced over the review period and submits that the resultant determinations are appropriate.

Load Forecast and Average Use Per Customer

Load forecasts are developed using the forecasted customer count and the weather normalized average use per customer. This is discussed thoroughly on a per customer class basis in Exhibit 3 Tab 2 Schedule 1.

Cost Allocation

CNPI's cost allocation methodology is based on the 2006 Cost Allocation Informational Filings submitted by Fort Erie and EOP. For the purposes of rate harmonization of electricity distribution rates in Fort Erie and EOP, CNPI has combined the inputs to the 2006 Cost Allocation Informational Filing model as if a single LDC.

The resultant outputs, the cost to revenue ratios, formed the basis of the cost allocations in the rate design of harmonized rates. This has been discussed thoroughly in the EOP pre-filed evidence Exhibit 10 Tab 1 Schedule 2.

Rate Design

In the harmonized rate design, CNPI has elected to harmonize the monthly service charge and the volumetric distribution charges. The recovery of Low Voltage charges have been excluded from this portion of the design. Low Voltage charges from Hydro One apply only in Gananoque and not in Fort Erie, therefore these charges will be in the form of a rate adder to the volumetric distribution charge in Gananoque.

In similar fashion, the respective distribution loss factors and retail transmission tariffs will also, for the purpose of these Applications, remain specific to each of the two service territories.

In general, those costs that have common cost drivers are being harmonized while those with cost drivers unique to the service territory remain segregated.

The basis of rate design is consistent with the Board Approved 2006 EDR and are appropriate for these applications.

Governing principles

As its governing principles in electricity distribution rate design, CNPI has considered the following matters:

- The Board's guidelines in the matter of class specific revenue to cost ratio ranges
- The notion of a 10% ceiling on total bill impact
- Fairness between the customer classes

Revenue to Cost Ratios

The rate design has respected the Board's guidelines[23] regarding the appropriate range of customer class revenue to costs ratios. For Unmetered Scattered Load, Street lights and Sentinel Lights it was necessary to limit the rate design revenue to cost ratio to a value less than the Board's guideline to respect the notion of a total bill impact of 10%. These instances are discussed more fully of the following class specific discussion.

CNPI submits that the revenue to cost ratios stemming from the rate design in these Applications is appropriate.

Fixed Variable Splits

CNPI's rate design maintained the proportions of customer class revenue requirement at the Board approved 2006 EDR levels as a staring point. CNPI has limited variations to the percentage split of class revenue requirement recovered through the fixed to variable split of the monthly service charge and volumetric service charge as a tool to minimize the total bill impact of the average customer of that customer class.

Rate Impacts

The rate impacts for the proposed harmonized distribution rates are set out in the following tables:

[23] Report of the Board, Application of Cost Allocation for Electricity Distributors, EB-2007-0667

Table 8-1 2009 Rate Impacts – Fort Eire

Class	Per Month kWh	Per Month kW	Monthly Delivery Charges: At Current Rates	At Proposed Rates	Change $	Change %	Total Bill: At Current Rates	At Proposed Rates	Change $	Change %
Residential	1,000		39.50	45.22	5.72	14.5	111.10	116.48	5.38	4.8
GS < 50 kW	2,000		85.38	90.42	5.04	5.9	232.90	236.93	4.03	1.7
GS > 50 kW	83,747	226	2,707.66	2,920.56	212.90	7.9	9,120.60	9,291.37	170.77	1.9
USL	750		34.06	61.61	27.55	80.9	85.22	113.67	28.46	33.4
Sentinel [1]	3,000	10	85.83	116.22	30.39	35.4	308.42	338.44	30.02	9.7
St. Light [2]	172,000	491	6,299.12	8,240.99	1,941.77	30.8	19,514.15	21,444.62	1,930.47	9.9

Selected Delivery Charge and Bill Impacts Per Proposed Rate Schedule

1 17 Connections billed
2 2873 Connections billed

Table 8-2 2009 Rate Impacts – EOP

Class	Per Month kWh	Per Month kW	Monthly Delivery Charges: At Current Rates	At Proposed Rates	Change $	Change %	Total Bill: At Current Rates	At Proposed Rates	Change $	Change %
Residential	1,000		32.62	43.66	11.04	33.9	110.93	122.55	11.62	10.5
GS < 50 kW	2,000		79.96	86.63	6.68	8.3	241.30	248.37	7.07	2.9
GS > 50 kW	44,320	139	1,709.51	1,816.03	106.52	6.2	5,426.17	5,539.29	113.11	2.1
USL	750		50.53	59.90	9.37	18.5	107.79	117.66	9.86	9.1
Sentinel [1]	3,000	10	78.20	105.49	27.30	34.9	321.54	350.28	28.75	8.9
St. Light [2]	46,000	129	1,619.76	1,708.90	89.14	5.5	5,469.84	5,564.76	94.91	1.7

Selected Delivery Charge and Bill Impacts Per Proposed Rate Schedule

1 15 Connections billed
2 557 Connections billed

The 2009 rate impacts for delivery charges, including the monthly service charge, volumetric distribution charge, regulatory asset recovery, Z-factor rate riders and retail transmission service, and the total bill have been extracted from updated evidence filed with CNPI's responses to Board Staff interrogatories. Specifically, in response to Board Staff Interrogatories No. 26, 28, 29, 31, 33, 38 and 40, CNPI filed revised rate design models; these rate impacts were determined in those models filed with the Board on December 12, 2008. The model used to determined harmonized rates is CNPI-Harmonized_DxDesign_20080815_R1.

The rate and total impacts cited above do not include future Board direction related to retail transmission service charges, regulatory asset recovery, rural or remote rate protection and commodity costs.

In the revised rate design submitted with CNPI's responses to Board Staff interrogatories on December 12, 2008, CNPI-Harmonized_DxDesign_20080815_R1, the total bill impact for the EOP residential customer class may exceed 10%. This is a result of limitations imposed on this rate design iteration. In this revised rate design model, CNPI-Harmonized_DxDesign_20080815_R1, CNPI addressed specific matters raised in the Board Staff interrogatories; there was no attempt made to further adjust revenue to cost ratios or fixed to variable splits to mitigate the resultant bill impacts. Such adjustments could be made to bring total bill impacts below 10%.

Low Voltage

Low voltage charges are applicable to EOP only; EOP is an embedded distributor within Hydro One Network's distribution system. Low voltage recovery in electricity distribution charges is applicable in EOP only.

Retail Transmission Service

Retail transmission service charges are unique to each service territory. Fort Erie has two delivery points connected to the IESO-Controlled grid and the cost driver is the uniform transmission rates applied by the IESO. In EOP, retail transmission charges are designed to recover charges imposed by Hydro One Networks.

In response to Board Staff interrogatories No. 66 and 68, Board Staff requested that CNPI develop new retail transmission service charges in accordance with the Board's Guideline G-2008-0001. CNPI provided its response with proposed retail transmission service charges effective May 1, 2009. These revised retail transmission service charges have not yet been factored into rates; CNPI will comply with Board direction in this matter.

Z-Factor Recovery

The Z-factor rate rider is applicable to Fort Erie only and is effective until August 30, 2009. The Z-factor storm recovery rate rider was approved by the Board in its Decision with Reasons, EB-2007-0514.

Wholesale Market Service Charge

CNPI has requested the previously approved amount of $0.0052 per kWh for both Fort Erie and EOP.

Rural or Remote Rate Protection

In its rate design, CNPI has proposed $0.0010 per kWh for the Rural or Remote Rate Protection charge. In a letter to the Board dated December 18, 2008, CNPI had requested approval to charge $0.0013 per kWh as per the Board's direction. CNPI will follow the Board's direction in this matter.

Commodity Costs

CNPI has used $0.0603 per kWh as the forecasted commodity costs. The Board's most recent report forecasts a price of $0.06072 per kWh as published in the Board's Regulated Price Plan Price Report May 1, 2009 to April 30, 2010. CNPI will follow the Board's direction in this matter.

Specific Customer Class Discussion

Residential

CNPI is proposing a revenue to cost ratio of 82.88%; increased from 80.52% but below the Board's guidelines. The revenue to cost ratio is limited by the total bill impact in

Gananoque. Higher bill impacts in EOP result from the significant loss of throughput which has been discussed thoroughly in the pre-filed evidence.

General Service less than 50 kW

CNPI is proposing a revenue to cost ratio of 120%; decreased from 133.5% and meeting the Board's guidelines.

Unmetered Scattered Load

CNPI is proposing a revenue to cost ratio of 44.69%; decreased from 57.76%. This does not meet the Board's guidelines. This is a function stagnant or declining customers and volumes in the face of increasing revenue requirement. CNPI has pushed the revenue to cost ratio to the maximum but is limited by the notional 10% total bill impact.

Currently, in Fort Erie the Unmetered Scatted Load customers are billed on a per connection basis where as at EOP the Unmetered Scatted Load customers are billed on a per customer basis with estimated consumption aggregated on a single bill. Effective May 1, 2009, upon the Board's approval of this application, Fort Erie will implement billing to the Unmetered Scattered Load class on a per customer basis.

Notwithstanding the rate impacts calculated by comparing the May 1, 2009 proposed rate structure to the May 1, 2008 rate structure the effective total bill impact will be significantly less. In the case of the customer with the most connections, 80 connections, with a totalized consumption of approximately 24,000 kWh the impact is approximately -19%. Customer with two or less connections will still see rate impacts greater than the 10% threshold that CNPI has established for implementation of rate impact mitigation. CNPI will work with these customers to determine a suitable solution.

Sentinel Lights

CNPI is proposing a revenue to cost ratio of 54.6%; increased from 37.46% but not meeting the Board's guidelines. CNPI has pushed the revenue to cost ratio to the maximum but is limited by the notional 10% total bill impact.

Street Lights

CNPI is proposing a revenue to cost ratio of 23.91%; increased from 19.51% but not meeting the Board's guidelines. CNPI has pushed the revenue to cost ratio to the maximum but is limited by the notional 10% total bill impact.

In response to Undertaking JT2.3, CNPI responded to the Board Staff's request to provide the impact on moving the revenue to cost ratio from the rate design quantum to a value of at least 50% of the spread from the Cost Allocation determination to the lower bound of the Board's guideline. The resultant impacts were provided to the Board in CNPI's response to that Undertaking. CNPI will comply with Board direction in this mater.

9.0 EFFECTIVE DATE FOR RATES

Both Fort Erie and EOP requested in their rate applications that their proposed rates be made effective on May 1, 2009. Because the distribution rates for Fort Erie and EOP were made interim as of May 1, 2009, the Board has the jurisdiction to make their rates effective on May 1, 2009.

Both Fort Erie and EOP filed their rate applications on August 15, 2008 in accordance with the Board's January 30, 2008 letter regarding its multi-year rate setting plan. Furthermore, Fort Erie and EOP met all deadlines set out in procedural orders during the course of the proceeding.

It is apparent that the delays in the proceeding can be attributed to disputes over the relevance of information requested by the SEC regarding the Port Colborne lease, CNPI's transmission business, Cornwall Electric and full-time equivalents. The SEC brought a motion to compel CNPI to provide this information, and on March 12, 2009 the Board denied the SEC's motion in all regards. The SEC made a motion to review and vary the March 12th decision in regard to the Port Colborne lease and was successful.

CNPI submits that its challenges to the SEC's requests were reasonable, despite the fact that CNPI was ultimately required to provide the Port Colborne information. As noted above, CNPI was successful in challenging the relevance of the information on its transmission business, Cornwall Electric and full-time equivalents. Furthermore, CNPI advanced rationale and reasonable arguments against disclosing the Port Colborne information. Accordingly, CNPI submits that an effective date of May 1, 2009 would be reasonable in this circumstance.

All of which is respectfully submitted by: ____________________

Andrew Taylor, Counsel for
Canadian Niagara Power Inc.
May 14, 2009

Appendix "A"

Tariff of Rates and Charges

The Tariff of Rates and Charges for CNPI – Fort Erie and CNPI – EOP, shown below, have been extracted from updated evidence filed with CNPI's responses to Board Staff interrogatories. Specifically, in response to Board Staff Interrogatories No. 26, 28, 29, 31, 33, 38 and 40, CNPI filed revised rate design models; these rate impacts were determined in those models filed with the Board on December 12, 2008. The model used to determined harmonized rates is CNPI-Harmonized_DxDesign_20080815_R1.

Canadian Niagara Power – Fort Erie

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.96
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	2.11
Distribution Volumetric Rate	$/kWh	0.0149
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0008
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0044
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
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less than 50 kW

Service Charge	$	21.34
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	1.85
Distribution Volumetric Rate	$/kWh	0.0228
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0024
Regulatory Asset Recovery	$/kWh	0.0001
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	148.15
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	12.42
Distribution Volumetric Rate	$/kW	8.0313
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.7737
Regulatory Asset Recovery	$/kW	0.0391

Retail Transmission Rate – Network Service Rate	$/kW	1.6442
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5973
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	36.39
Service Charge (per customer) Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.91
Distribution Volumetric	$/kWh	0.0214
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kWh	0.0024
Regulatory Asset Recovery	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0040
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.94
Service Charge Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.21
Distribution Volumetric Rate	$/kW	3.3256
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.2105
Regulatory Asset Recovery	$/kW	0.0574
Retail Transmission Rate – Network Service Rate	$/kW	1.3124
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2607
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.69
Service Charge (per connection) Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$	0.14
Distribution Volumetric Rate	$/kW	3.2908
Distribution Volumetric Rate Rider for Storm Damage Cost Recovery – effective until August 31, 2009	$/kW	0.1691
Regulatory Asset Recovery	$/kW	0.0445
Retail Transmission Rate – Network Service Rate	$/kW	1.2400
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2348
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge – no disconnect – after regular hours	$	165.00
Disconnect/Reconnect Charges at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges at meter - after regular hours	$	185.00
Disconnect/reconnect at pole – during regular hours	$	185.00
Disconnect/reconnect at pole – after regular hours	$	415.00

Install/remove load control device – during regular hours	$	65.00
Install/remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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)

Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing charge, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50

Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party

Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Loss Factors

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0391
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0287

Canadian Niagara Power – Eastern Ontario Power

TARIFF OF RATES AND CHARGES

Effective May 1, 2009

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	17.96
Distribution Volumetric Rate	$/kWh	0.0165
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0041
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service Less than 50 kW

Service Charge	$	21.34
Distribution Volumetric Rate	$/kWh	0.0243
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate-Network Service Rate	$/kWh	0.0039
Retail Transmission Rate-Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	148.15
Distribution Volumetric Rate	$/kW	8.5082
Regulatory Asset Recovery	$/kW	0.0656
Retail Transmission Rate - Network Service Rate	$/kW	1.6231
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5725
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per customer)	$	36.39
Distribution Volumetric Rate	$/kWh	0.0229
Regulatory Asset Recovery	$/kWh	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0039
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge	$	2.94
Distribution Volumetric Rate	$/kW	3.5360
Regulatory Asset Recovery	$/kW	0.0727
Retail Transmission Rate – Network Service Rate	$/kW	1.1972
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1635
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.69
Distribution Volumetric Rate	$/kW	3.3832
Regulatory Asset Recovery	$/kW	0.0687
Retail Transmission Rate – Network Service Rate	$/kW	1.1911
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.1396
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification Charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection – during regular hours	$	30.00
Collection of account charge – no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charges at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges at meter - after regular hours	$	185.00
Disconnect/reconnect at pole – during regular hours	$	185.00
Disconnect/reconnect at pole – after regular hours	$	415.00
Install/remove load control device – during regular hours	$	65.00
Install/remove load control device – after regular hours	$	185.00
Service call – customer-owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

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)

Retail Service Charges (if applicable)

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

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly fixed charge per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing charge, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50

Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party

Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0719
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0612