CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

August 13, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: 2013 ELECTRICITY DISTRIBUTION RATE APPLICATION FOR CANADIAN NIAGARA POWER INC., ("CNPI") EB-2012-0112

Please find accompanying this letter a revised copy of CNPI's responses to the interrogatories submitted to the Board by Board staff, the Energy Probe Research Foundation, the School Energy Coalition and the Vulnerable Energy Consumers Coalition. This revised copy includes responses to the following interrogatories which were omitted in the original submission:

Board Staff #8
School Energy Coalition #2
Energy Probe Research Foundation #24

Two (2) hard copies will also be sent by courier at a later date.

If you have any questions in connection with the above matter, please do not hesitate to contact the undersigned at (905) 994-3634.

Yours truly,

Original signed by

Douglas Bradbury P.Eng,
Director Regulatory Affairs

Enclosure

Canadian Niagara Power Inc. ("CNPI")
2013 Electricity Distribution Rates
EB-2012-0112

Draft Issues List

1. General

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

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

1.3 Is service quality, based on the Board specified performance indicators, acceptable?

1.4 Is the proposal to align the rate year with CNPI's fiscal year, and for rates effective January 1, 2013 appropriate?

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

2.2 Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

2.3 Is the CNPI – Fort Erie/Gananoque working capital allowance for the test year appropriate?

2.4 Is the CNPI – Port Colborne working capital allowance for the test year appropriate?

2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

3. Load Forecast and Operating Revenue

3.1 Is the load forecast methodology including weather normalization appropriate?

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

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

3.4 Is the test year forecast of other revenues appropriate?

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

4.2 Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

4.3 Are the methodologies used to allocate shared services and other costs appropriate?

4.4 Is CNPI – Fort Erie/Gananoque's proposed level of depreciation/amortization expense for the test year appropriate?
4.5 Is CNPI – Port Colborne's proposed level of depreciation/amortization expense for the test year appropriate?
4.6 Is the proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?
4.7 Is the proposed CNPI – Port Colborne forecast for Income Taxes for the test year appropriate?
4.8 Are the 2013 compensation costs and employee levels appropriate?
4.9 Is the test year forecast of property taxes appropriate?

5. Capital Structure and Cost of Capital

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

6. Smart Meters

6.1 Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?
6.2 Is proposed treatment of stranded meter costs appropriate?

7. Cost Allocation

7.1 Is the proposed CNPI – Fort Erie/Gananoque cost allocation appropriate?
7.2 Is the proposed CNPI – Port Colborne cost allocation appropriate?
7.3 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?
7.4 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

8. Rate Design

8.1 Are the fixed to variable splits for each class appropriate?
8.2 Are the proposed retail transmission service rates appropriate?
8.3 Are the proposed LV rates appropriate?
8.4 Are the proposed loss factors appropriate
8.5 Is CNPI's proposal to continue with its approved Transformer Ownership Allowance appropriate?

9. Rate Harmonization

9.1 Is CNPI's proposed rate harmonization appropriate?
9.2 Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

10. Deferral and Variance Accounts

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

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

11. Accounting Standards for Private Enterprise ("ASPE")

11.1 Are the proposed Revenue Requirements determined using ASPE appropriate?

11.2 Is the proposed change in accounting policy regarding the capitalization of overhead costs appropriate?

11.3 Is the treatment of property, plant & equipment due to the transition to a new accounting standard appropriate?

12. Green Energy Act Plan

12.1 Is CNPI's proposed Green Energy Act Plan appropriate?

Cross Reference Sheet for Energy Probe Interrogatories

Energy Probe	CNPI
EP 2.1 Interr. #1 page.2.	EP- #1
EP 2.1 Interr. #2 page . 2.	EP- #2
EP 2.1 Interr. #3 page .2.	EP- #3
EP 2.1 Interr. #4 page. 3.	EP- #4
EP 2.1 Interr. #5 page.3.	EP- #5
EP 2.1 Interr. #6 page. 3.	EP- #6
EP 2.1 Interr. #7 page. 3.	EP- #7
EP 2.1 Interr. #8 page. 4.	EP- #8
EP 2.1 Interr. #9 page. 4.	EP- #9
EP 2.1 Interr. #10 page. 4.	EP- #10
EP 2.1 Interr. #11 page .5.	EP- #11
EP 2.1 Interr. #12 page . 5.	EP- #12
EP-2.1 Interr. #13 page .6.	EP- #13
EP 2.1 Interr. #14 page. 6.	EP- #14
EP 2.1 Interr. #15 page .6.	EP- #15
EP 2.1 Interr. #16 page 7.	EP- #16
EP 2.1 Interr. #17 page.7.	EP- #17
EP 2.1 Interr. #18 page.7.	EP- #18
EP 2.1 Interr. #19 page .8.	EP- #19
EP 2.1 Interr. #20 page .8.	EP- #20
EP 2.1 Interr. #21 page .9.	EP- #21
EP 2.2 Interr. #1 page 9.	EP- #22
EP 2.2 Interr. #2 page .9.	EP- #23
EP 2.2 Interr. #3 page .9.	EP- #24
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EP 2.3 Interr. #2 page .11.	EP- #27
EP 2.4 Interr. #1 page .11.	EP- #28
EP 2.4 Interr. #2 page .11.	EP- #29
EP 2.5 Interr. #1 page .12.	EP- #30
EP 2.5 Interr. #2 page .12.	EP- #31
EP 2.6 Interr. #1 page .12.	EP- #32
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EP 3.2 Interr. #2 page .13.	EP- #36
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Canadian Niagara Power Inc.

EB-2012-0112

Response to General Interrogatories

1. General

1.1

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

(OEB)

General

1. Responses to Letters of Comment

Following publication of the Notice of Application, did CNPI receive any letters of comment? If so, please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information except for the name is redacted. If not confirmed, please explain why a response was not sent and confirm if the applicant intends to respond.

RESPONSE:

CNPI did not receive any letters of comment following publication of the Notice of Application.

CNPI acknowledges that as of July 17, 2012, there are five letters of comment posted on the Board's public website associated with EB-2012-0112 all of which are redacted. None of these five letters were directed, by way of copy, to CNPI and as such CNPI has not attempted to identify and respond to the authors.

(OEB)

General

2. Condition of Service

a) Please identify any rates and charges that are included in the applicant's conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.
b) If any rates or charges are identified in part a), please provide a schedule outlining the revenues recovered from these rates and charges from 2009 to 2011 and the revenue forecasted for the 2012 bridge and 2013 test years.
c) If any rates or charges are identified in part a), please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

RESPONSE:

a) As stated in Exhibit 1, Tab 1, Schedule 18, on page 1 of 1, CNPI does not identify any rates and charges in its Conditions of Service.

b) Not applicable.

c) Not applicable.

(OEB)

3. Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

RESPONSE:

Please see the responses to Board Staff interrogatories #73 (c) and (d).

(OEB)

4. Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

RESPONSE:

Please see the responses to Board Staff interrogatories #73 (c) and (d).

(OEB)

5. Ref: E1/T1/S1

The Board in a letter dated January 26, 2012 identified those electricity distributors, which included CNPI, which it expected to file a cost of service application for 2013 rates. In this regard the Board indicated that applicants that wished to request cost of service rates effective January 1, 2013 should file their applications sooner, and no later than April 27, 2012.

The Board also expected that distributors filing applications in advance of any revisions to the Filing Requirements for Transmission and Distribution Applications would update their applications in due course to address any material changes that may be reflected in the revised Filing Requirements. The Board on June 28, 2012 issued the filing requirements for 2013. Please complete and file the following appendices, in addition to any others specifically identified in the interrogatories that follow: 2-A, 2-CA, 2-CB, 2-CC, 2-CD, 2-D, 2-EA, 2-F, 2-L, 2-M and 2-N.

RESPONSE:

CNPI has transitioned to ASPE and is not implementing IFRS. CNPI is changing its capitalization policy and depreciation rates effective Jan 1, 2013 in order to comply with the OEB direction on MIFRS. Since CNPI is not implementing IFRS, there is no transition year with respect to the change in capitalization policy or depreciation rates.

The following is a list of the requested schedules:

Appendix 2-A – attached

Appendix 2-CA – is attached as Appendix 2-CE

Appendix 2-CB – is attached as Appendix 2-CF

Appendix 2- CC – is attached as Appendix 2-CG

Appendix 2- CD – N/A

Appendix 2-D – attached

Appendix 2-EA – N/A

Appendix 2-F – done as Appendix 2-C in E3T3S3 and E3T4S2, no change for MIFRS

Appendix 2-L - done as Appendix 2-I in E4T2S5 and E4T2S14, see response to OEB #25

Appendix 2-M – is attached as Appendix 2-H

Appendix 2-N – done as Appendix 2-L in E4T5S2 pages 1 and 2, see response to OEB #25

Appendix 2-A
Capital Projects Table - FE and EOP

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**ASPE**	**ASPE**	**MIFRS**
Delta to Wye Conversion							
Poles, towers & fixtures	68,550	2,059	62,466	19,052	6,004	91,596	93,909
OH Cond & Devices	153,653	77,717	503,671	74,353	95,494	183,191	187,817
UG Conduit & Manholes			1,412	1,951	1,846		
UG Cond & Devices	2,944	1,073	3,234	1,491	7,030		
Line transformers	13,260	5,425	17,744	15,293	4,114		
Meters				2,276	958		
Sub-Total	238,407	86,274	588,527	114,416	115,446	274,787	281,726
New transformers							
Poles, towers & fixtures	25,743	2,284					
OH Cond & Devices	3,484	1,803					
UG Cond & Devices	7						
Line transformers	178,211	273,240	213,854	171,618	268,323	262,435	276,580
Sub-Total	207,445	277,327	213,854	171,618	268,323	262,435	276,580
Distribution Upgrades							
Poles, towers & fixtures	324,390	481,430	381,047	271,466	284,556	695,522	702,764
OH Cond & Devices	628,189	628,059	515,488	491,727	405,416	545,195	520,973
UG Conduit & Manholes	35	4,162	9,841	1,492	1,933		
UG Cond & Devices	79,301	103,468	484,281	44,552	69,265	45,396	44,554
Line transformers	31,015	52,390	70,466	77,885	103,602		
Services	22,683	24,681		3,991	170,937	114,284	97,584
Meters	518	4,510		2,731	5,660		
Sub-Total	1,086,131	1,298,700	1,461,123	893,844	1,041,369	1,400,397	1,365,875
Transportation Equipment							
Transportation Equipment	464,848	547,806	257,541	63,841	93,173	650,000	390,000
Tools,shop & garage equip		9,309					
Sub-Total	464,848	557,115	257,541	63,841	93,173	650,000	390,000
Dist Rebuilds Storms							
Poles, towers & fixtures	34,244	49,872	43,318				30,308
OH Cond & Devices	25,471	111,816	65,348				15,154
UG Conduit & Manholes		14					
UG Cond & Devices	7,262	706	4,020				5,051
Line transformers		339	3,191				
Sub-Total	66,977	162,747	115,877	0	0	0	50,513
Dist Analysis Tools							
Computer Software			107,879	191,272	160,966		
Computer Hardware					3,229		
Poles, towers & fixtures					880		
OH Cond & Devices					4,840		
Misc equipment						185,296	182,671
Sub-Total	0	0	107,879	191,272	169,915	185,296	182,671

Substation							
Station Equipment	1,820,563					67,237	64,804
Sub-Total	1,820,563	0	0	0	0	67,237	64,804
New meters							
Meters	131,381					81,420	95,554
Computer hardware	24,513						
Sub-Total	155,894	0	0	0	0	81,420	95,554
Install Reclos. Ratio transformer							
Station Equipment	131,312						
System Supv Equipment	52,823						
OH Cond & Devices						100,202	170,683
Sub-Total	184,135	0	0	0	0	100,202	170,683
New Service Lines							
Poles, towers & fixtures	211,809	82,323	383,060	10,219			
OH Cond & Devices	161,267			1,353			
UG Conduit & Manholes	17,114	9,474	12,722	296			
UG Cond & Devices	221,447	15,461					
Line transformers	20,942	23,836	30,323	4,675			
Services	401,748	443,853	740,887	47,246			
Meters	4,933	561	624				
Land right				5,593			
Sub-Total	1,039,260	575,508	1,167,616	69,382	0	0	0
Service Centre							
Buildings & Fixtures	233,948						
Sub-Total	233,948	0	0	0	0	0	0
Land Purchases							
Land	188,431						
Sub-Total	188,431	0	0	0	0	0	0
IT projects							
Computer Hardware	63,770	61,473	226,273	488,671	125,400	452,065	8,742
Computer Software	135,190	190,796	230,075	1,111,344	367,873	312,247	554,634
Sub-Total	198,960	252,269	456,348	1,600,015	493,273	764,312	563,376
Queen St. Underground							
Poles, towers & fixtures		6,570					
OH Cond & Devices		38,562					
UG Cond & Devices		2,428					
Line transformers		465					
Office furniture & equip		18,178					
Sub-Total	0	66,203	0	0	0	0	0
Station 13							
Station Equipment		231,641					
Sub-Total	0	231,641	0	0	0	0	0
Upgrade VHF Radio System							
Communication equipment		165,508					
Sub-Total	0	165,508	0	0	0	0	0

Phone System							
Communication equipment		110,630				250,000	
Sub-Total	0	110,630	0	0	0	250,000	0
Sub Transmission Line							
Poles, towers & fixtures			70,943	84,230			
OH Cond & Devices			57,157	126,861	51,440		
UG Cond & Devices			57	1,933			
Line transformers				1,631			
Sub-Total	0	0	128,157	214,655	51,440	0	0
Overhead Services							
Poles, towers & fixtures			78,737	9,343	78,628		
OH Cond & Devices			215,093	150	2,166		
UG Conduit & Manholes			5,684	5,755	987		
UG Cond & Devices			6,867				
Line transformers			14,015	3,743	20,156		
Services				135,525	333,295	203,801	239,149
Meters					930		
Sub-Total	0	0	320,396	154,516	436,162	203,801	239,149
Garrison Rd. Upgrade							
Poles, towers & fixtures			27,828				
OH Cond & Devices			138,302				
UG Conduit & Manholes			7,446				
UG Cond & Devices			322,454				
Line transformers			25,941				
Sub-Total	0	0	521,971	0	0	0	0
Leasehold Improvements							
Leasehold Improvements			54,805		289,975		
Sub-Total	0	0	54,805	0	289,975	0	0
Engineering Project							
Poles, towers & fixtures				57,600		30,693	28,864
OH Cond & Devices				5,063		15,347	14,432
Station Equipment					68,817		
UG Cond & Devices						15,347	14,432
Sub-Total	0	0	0	62,663	68,817	61,387	57,728
Underground Services							
Poles, towers & fixtures				3,598	55,699		
OH Cond & Devices				1,612	147,905		
UG Conduit & Manholes				1,595	5,410		
UG Cond & Devices				4,255	62,418		
Line transformers				2,771	23,763		
Services				118,810	224,157	197,184	226,085
Meters				605	826		
Sub-Total	0	0	0	133,246	520,178	197,184	226,085
Station 12							
Station Equipment					147,309	91,072	129,324
UG Cond & Devices						39,031	55,425
Sub-Total	0	0	0	0	147,309	130,103	184,749

St. George Crt. Rebuild							
Poles, towers & fixtures					10,101		
OH Cond & Devices					11,612		
UG Conduit & Manholes					449		
UG Cond & Devices					282,681		
Line transformers					8,522		
Sub-Total	0	0	0	0	313,365	0	0
Dist. Station 19							
Station Equipment						179,949	
Sub-Total	0	0	0	0	0	179,949	0
Dodds Crt Rebuild							
UG Conduit & Manholes						64,829	
UG Cond & Devices						97,243	
Sub-Total	0	0	0	0	0	162,072	0
Stevensville Project							
Poles, towers & fixtures						117,405	108,999
OH Cond & Devices						50,316	46,714
Sub-Total	0	0	0	0	0	167,721	155,713
Environmental PCB							
Station Equipment						170,000	130,000
Poles, towers & fixtures						45,000	45,000
Line transformers						105,000	105,000
Sub-Total	0	0	0	0	0	320,000	280,000
Upgrade Scada System							
System Supv Equipment							55,792
Sub-Total	0	0	0	0	0	0	55,792
CIAC							
Distribution Upgrades	-80,036	-892,414	-506,954	-23,722	-169,045	-277,924	-225,000
New Service Lines	-251,093	-145,401	-122,691	-26,020			
Delta to Wye Conversion		-12,471			-5,532		
Sub Transmission Line				-36,876			
OH services				-19,582	-49,967	-20,000	-20,000
UG services				-70,062	-68,927	-40,000	-40,000
Dodds Crt Rebuild						-40,000	
Miscellaneous	-84,601	-255,285	-2,173	-438,111	-210,281		
Sub-Total	-415,730	-1,305,571	-631,818	-614,373	-503,752	-377,924	-285,000
GEC							
GEC	876,564	738,862	717,900	399,058	730,377	732,660	
Sub-Total	876,564	738,862	717,900	399,058	730,377	732,660	0
AUC							
transfers to capital	-7,299,673	-4,937,603	-6,500,376	-4,541,392	-5,144,836	-6,651,946	-5,832,747
transfers in	5,599,656	6,844,631	5,222,846	5,189,448	5,385,937	6,788,557	5,962,391
Sub-Total	-1,700,017	1,907,028	-1,277,530	648,056	241,101	136,611	129,644
Miscellaneous	538,111	414,818	388,382	472,866	405,716	460,983	431,315
Total	**5,183,927**	**5,539,059**	**4,591,028**	**4,575,075**	**4,882,187**	**6,410,633**	**4,916,957**

Notes:

1 Please provide a breakdown of the major components of each capital project. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 Amounts should be reported on a MIFRS basis for the adoption year and any subsequent years, only.

Appendix 2-A
Capital Projects Table
Port Colborne

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**ASPE**	**ASPE**	**MIFRS**
Dist. Upgrades & Expansions							
Poles, towers & fixtures	78,167	202,097	89,808	55,801	86,062	308,632	231,694
OH Cond & Devices	179,445	224,144	145,693	178,908	153,067	231,579	219,236
UG Conduit & Manholes	678	2,152	73,207	1,025	911	68,631	71,694
UG Cond & Devices	57,595	57,113	132,107	67,388	6,869		
Line transformers	6,579	6,234	27,743	31,519	32,726		
Services					8,903		
Meters	9,493	616		1,054	910		
Land right				6,337			
Office furniture & equip					15,182		
Sub-Total	331,957	492,356	468,558	342,032	304,630	608,842	522,624
New Services							
Poles, towers & fixtures	47,121	74,153	41,487	0	0	0	0
OH Cond & Devices	31,757	9,203					
UG Conduit & Manholes	4,155	13,204	10,669				
UG Cond & Devices	23,801						
Line transformers	13,139	1,256	7,653				
Services	97,792	98,264	130,877				
Meters	1,387	1,179					
Sub-Total	219,152	197,259	190,686	0	0	0	0
New Transformers & Regulators							
Line transformers	81,329	160,123		99,115	119,491	120,000	120,000
Sub-Total	81,329	160,123	0	99,115	119,491	120,000	120,000
Mobile Substation							
Transportation equipment		77,494					
Station equipment			96,268				
Sub-Total	0	77,494	96,268	0	0	0	0
Dist. Rebuilds Storm							
Poles, towers & fixtures			36,345				31,266
OH Cond & Devices			77,579				15,633
UG Conduit & Manholes			391				5,211
UG Cond & Devices			4,591				
Line transformers			1,490				
Sub-Total	0	0	120,396	0	0	0	52,110
Sherdston Shores Station							
Station equipment			2,254,160	146,772			
Sub-Total	0	0	2,254,160	146,772	0	0	0
New meters							
Line transformers				40,249			
Meters				17,265		57,096	74,567
Sub-Total	0	0	0	57,514	0	57,096	74,567

Recloser Installation							
Poles, towers & fixtures				6,398	4,658	75,551	87,373
OH Cond & Devices				22,632			
Other Install on Cust Prem				48,696	7,523		
Station equipment					116,203		
System Supv Equipment						8,395	9,708
Sub-Total	0	0	0	77,726	128,384	83,946	97,081
Overhead Services							
Poles, towers & fixtures				5,956	29,953		
OH Cond & Devices				485			
UG Conduit & Manholes				725			
UG Cond & Devices							
Line transformers				725	11,947		
Services				61,301	158,283	116,494	139,537
Meters				1,280			
Sub-Total	0	0	0	70,472	200,183	116,494	139,537
Underground Services							
Poles, towers & fixtures				5,136	7,575		
OH Cond & Devices				14			
UG Conduit & Manholes				2,256	1,058		
UG Cond & Devices				1,523			
Line transformers				664	1,326		
Services				40,597	124,102	122,474	125,053
Meters				440	718		
Sub-Total	0	0	0	50,630	134,779	122,474	125,053
Barrick St. Station							
Station equipment						144,122	178,995
Sub-Total	0	0	0	0	0	144,122	178,995
Poletran replacement							
UG Conduit & Manholes						19,204	27,038
UG Cond & Devices						57,611	81,113
Sub-Total	0	0	0	0	0	76,815	108,151
Environmental PCB							
Station equipment						200,000	150,000
Sub-Total	0	0	0	0	0	200,000	150,000
CIAC							
Distribution Upgrades	-19,142	-97,570	-6,329	-71,162	-108,902	-109,110	-110,000
New Service Lines	-25,481		-4,566				
OH services				-36,717	-22,714	-10,000	-10,000
UG services				-6,858	-82,452	-20,000	-20,000
Sherkston Shores			-857,619				
Miscellaneous	-34,749	-9,215	-642	-117,905	-138,673		
Sub-Total	-79,372	-106,785	-869,156	-232,642	-352,741	-139,110	-140,000

GEC							
GEC	411,539	306,331	297,294	107,423	249,879	334,121	
Sub-Total	411,539	306,331	297,294	107,423	249,879	334,121	0
AUC							
transfers to capital	-1,348,711	-1,274,069	-3,449,995	-987,764	-1,429,124	-1,946,849	-2,043,555
transfers in	1,249,157	1,847,227	2,897,516	1,273,607	1,409,932	1,983,144	2,080,735
Sub-Total	-99,554	573,158	-552,479	285,843	-19,192	36,295	37,180
Miscellaneous	304,735	40,506	22,632	36,080	291,778	82,938	123,143
Total	**1,169,786**	**1,740,442**	**2,028,359**	**1,040,965**	**1,057,191**	**1,844,033**	**1,588,441**

Notes:

1 Please provide a breakdown of the major components of each capital project. Please ensure that all projects below the materiality

2 Amounts should be reported on a MIFRS basis for the adoption year and any subsequent years, only.

Appendix 2-CE
Depreciation and Amortization Expense
2011
FE and EOP

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense per Fixed Asset Continuity Schedule (i)	Variance (m) = (h) - (i)
1608	Franchises & Consents	156,053	-	156,053	-	-	156,053	40.00	2.50%	3,901	3,901	(0)
1805	Land	189,861	-	189,861	-	-	189,861				-	-
1806	Land Rights	173,456	49,918	123,537	27,510	(15,021)	136,027	40.00	2.50%	3,401	3,401	(0)
1808	Buildings	3,725,084	-	3,725,084	-	(0)	3,725,084	50.00	2.00%	74,502	74,502	(0)
1820	Substation Equipment	5,693,360	100,000	5,593,360	270,515	(143,652)	5,720,223	33.33	3.00%	171,624	171,624	-
1830	Poles, Towers & Fixtures	15,535,267	990,485	14,544,782	555,750	(283,720)	14,816,812	25.00	4.00%	592,672	592,672	-
1835	OH Conductors & Devices	19,314,427	1,416,697	17,897,731	970,641	(498,300)	18,370,071	33.33	3.00%	551,157	551,157	-
1840	UG Conduit	678,892	-	678,892	12,558	(7,806)	683,645	50.00	2.00%	13,673	13,673	-
1845	UG Conductors & Devices	5,458,097	16,974	5,441,123	499,153	(405,089)	5,535,186	33.33	3.00%	166,072	166,072	-
1850	Line Transformers	9,824,406	870,444	8,953,961	518,384	(220,915)	9,251,430	33.33	3.00%	277,571	277,571	-
1855	Services (OH & UG)	6,427,321	332,749	6,094,572	888,844	(713,551)	6,269,865	33.33	3.00%	188,115	188,115	-
1860	Meters	611,735	59,403	552,333	75,764	(34,154)	593,943	33.33	3.00%	17,820	17,820	0
1860A	Meters	2,421,361	263,045	2,158,315	-	(0)	2,158,315	25.00	4.00%	86,333	86,333	0
1908	Buildings & Fixtures	847,161	-	847,161	5,211	(3,143)	849,229	50.00	2.00%	16,985	16,985	-
1910	Leasehold Improvements	60,390	-	60,390	333,424	(185,618)	208,196	5.00	20.00%	41,639	41,639	-
1915	Office Furniture & Equipment 10yr	1,325,747	956,968	368,779	6,432	(659)	374,552	10.00	10.00%	37,455	37,455	-
1920	Computer - Hardware	2,303,830	921,854	1,381,976	279,691	(139,846)	1,521,821	5.00	20.00%	304,364	304,364	-
1925	Computer Software	7,205,303	2,698,910	4,506,393	548,418	(258,222)	4,796,590	10.00	10.00%	479,659	479,659	0
1930	Transportation Equipment	2,781,303	235,009	2,546,293	148,406	(0)	2,694,699	10.00	10.00%	269,470	269,470	0
1930A	Transportation Equipment	483,429	193,191	290,238	-	(0)	290,238	5.00	20.00%	58,048	58,047	0
1935	Stores Equipment	166,152	105,590	60,562	-	-	60,562	10.00	10.00%	6,056	6,056	-
1940	Tools, Shop & Garage Equipment	673,290	556,316	116,975	2,810	(453)	119,331	10.00	10.00%	11,933	11,933	-
1945	Measurement & Testing Equipment	478,244	285,504	192,739	-	-	192,739	10.00	10.00%	19,274	19,274	(0)
1950	Power operated Equipment	109,339	85,203	24,137	-	-	24,137	10.00	10.00%	2,414	2,414	0
1955	Communications Equipment	664,670	241,033	423,637	1,080	(540)	424,177	20.00	5.00%	21,209	21,209	(0)
1960	GA Misc. Equip	82,856	47,476	35,381	-	-	35,381	5.00	20.00%	7,076	7,076	(0)
1960A	GA Misc. Equip	59,693	-	59,693	-	(0)	59,693	10.00	10.00%	5,969	5,969	(0)
1980	System Supervisor Equipment	742,253	277,179	465,073	247	(123)	465,197	10.00	10.00%	46,520	46,520	-
1980A	System Supervisor Equipment	3,067	3,067	-	-	-	-	5.00	20.00%	-	-	-
1995	Contributions & Grants	(6,962,434)	(456,008)	(6,506,426)	(503,752)	169,109	(6,841,070)	30.00	3.33%	(228,036)	(228,036)	-
	Total	81,233,613	10,251,007	70,982,607	4,641,084	(2,741,704)	72,881,987			3,246,875	3,246,875	0

Appendix 2-CE
Depreciation and Amortization Expense
2011
Port Colborne

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense per Fixed Asset Continuity Schedule (i)	Variance (m) = (h) - (i)
1806	Land Rights	58,684	-	58,684	7,348	(6,599)	59,434	40.00	2.50%	1,486	1,486	-
1808	Buildings	241,652	-	241,652	-	-	241,652	50.00	2.00%	4,833	4,833	0
1820	Substation Equipment	5,207,372	-	5,207,372	155,729	(154,366)	5,208,734	33.33	3.00%	156,278	156,278	-
1830	Poles, Towers & Fixtures	2,325,515	-	2,325,515	186,704	(133,881)	2,378,339	25.00	4.00%	95,134	95,134	-
1835	OH Conductors & Devices	2,832,521	-	2,832,521	233,994	(140,106)	2,926,409	33.33	3.00%	87,801	87,801	-
1840	UG Conduit	150,314	-	150,314	6,047	(2,633)	153,728	50.00	2.00%	3,075	3,075	-
1845	UG Conductors & Devices	867,152	-	867,152	176,753	(60,220)	983,685	33.33	3.00%	29,513	29,513	-
1850	Line Transformers	1,739,174	-	1,739,174	222,575	(158,756)	1,802,993	33.33	3.00%	54,095	54,095	-
1855	Services (OH & UG)	896,139	-	896,139	350,940	(266,996)	980,083	33.33	3.00%	29,405	29,405	-
1860	Meters	477,688	-	477,688	49,352	(41,659)	485,381	25.00	4.00%	19,415	19,415	-
1865	Other Install on Cust Prem	56,537	(10,052)	66,589	7,523	-	74,111	10.00	10.00%	7,411	7,411	-
1908	Buildings & Fixtures	140,139	-	140,139	149	-	140,288	50.00	2.00%	2,806	2,806	0
1915	Office Furniture & Equipment 10yr	7,486	3,813	3,673	15,182	-	18,855	10.00	10.00%	1,886	1,886	0
1920	Computer - Hardware	76,764	-	76,764	16,829	(5,472)	88,121	5.00	20.00%	17,624	17,624	-
1925	Computer Software	153,073	-	153,073	-	-	153,073	10.00	10.00%	15,307	15,307	(0)
1935	Stores Equipment	486	-	486	-	-	486	10.00	10.00%	49	49	-
1940	Tools, Shop & Garage Equipment	14,089	7,609	6,480	-	-	6,480	10.00	10.00%	648	648	-
1955	Communications Equipment	111,984	50,143	61,842	-	-	61,842	20.00	5.00%	3,092	3,092	-
1980	System Supervisor Equipment	30,562	-	30,562	-	-	30,562	10.00	10.00%	3,056	3,056	(0)
1995	Contributions & Grants	(1,533,026)	38,600	(1,571,626)	(352,741)	306,883	(1,617,484)	30.00	3.33%	(53,916)	(53,916)	-
	Total	13,854,305	90,113	13,764,192	1,076,383	(663,804)	14,176,771			478,998	478,998	0

Appendix 2-CF
Depreciation and Amortization Expense
2012
FE and EOP

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense per Fixed Asset Continuity Schedule (i)	Variance (m) = (h) - (i)
1608	Franchises & Consents	156,053	-	156,053	-	-	156,053	40.00	2.50%	3,901	3,901	(0)
1805	Land	189,861	-	189,861	-	-	189,861				-	-
1806	Land Rights	200,966	49,918	151,048	15,000	(7,500)	158,548	40.00	2.50%	3,964	3,964	-
1808	Buildings	3,725,084	0	3,725,084	33,106	(16,553)	3,741,637	50.00	2.00%	74,833	74,833	(0)
1820	Substation Equipment	5,963,875	100,617	5,863,258	612,867	(306,433)	6,169,692	33.33	3.00%	185,109	185,109	0
1830	Poles, Towers & Fixtures	16,083,180	1,094,589	14,988,592	1,186,570	(593,285)	15,581,877	25.00	4.00%	623,275	623,275	-
1835	OH Conductors & Devices	20,282,805	1,416,806	18,865,999	1,054,627	(527,313)	19,393,313	33.33	3.00%	581,858	581,858	-
1840	UG Conduit	691,451	(2)	691,453	75,671	(37,836)	729,288	50.00	2.00%	14,586	14,586	-
1845	UG Conductors & Devices	5,957,249	32,332	5,924,917	257,345	(128,706)	6,053,555	33.33	3.00%	181,625	181,625	-
1850	Line Transformers	10,342,789	871,248	9,471,541	432,807	(216,568)	9,687,779	33.33	3.00%	290,662	290,662	-
1855	Services (OH & UG)	7,316,165	350,176	6,965,989	630,434	(315,291)	7,281,132	33.33	3.00%	218,456	218,456	-
1860	Meters	687,500	(949,112)	1,636,611	132,219	(66,110)	1,702,721	33.33	3.00%	51,087	51,087	0
1860A	Meters	2,421,361	301,615	2,119,745	-	-	2,119,745	25.00	4.00%	84,790	84,790	0
1908	Buildings & Fixtures	852,372	(0)	852,372	-	-	852,372	50.00	2.00%	17,047	17,047	(0)
1910	Leasehold Improvements	393,814	(0)	393,814	25,000	(12,500)	406,314	5.00	20.00%	81,263	81,263	-
1915	Office Furniture & Equipment 10yr	1,332,178	997,226	334,952	3,063	(1,532)	336,483	10.00	10.00%	33,648	33,648	-
1920	Computer - Hardware	2,583,125	1,037,318	1,545,807	571,345	(285,672)	1,831,479	5.00	20.00%	366,296	366,296	-
1925	Computer Software	7,753,721	2,713,120	5,040,602	399,592	(199,796)	5,240,398	10.00	10.00%	524,040	524,040	-
1930	Transportation Equipment	2,805,852	293,062	2,512,790	650,000	(325,000)	2,837,790	10.00	10.00%	283,779	283,779	-
1930A	Transportation Equipment	483,429	235,904	247,525	-	-	247,525	5.00	20.00%	49,505	49,505	-
1935	Stores Equipment	166,152	119,876	46,277	-	-	46,277	10.00	10.00%	4,628	4,628	-
1940	Tools, Shop & Garage Equipment	676,100	562,239	113,861	22,197	(11,099)	124,960	10.00	10.00%	12,496	12,496	(0)
1945	Measurement & Testing Equipment	478,244	286,480	191,764	21,755	(10,877)	202,641	10.00	10.00%	20,264	20,264	-
1950	Power operated Equipment	109,339	85,203	24,137	-	-	24,137	10.00	10.00%	2,414	2,414	0
1955	Communications Equipment	665,750	270,262	395,488	272,786	(136,393)	531,881	20.00	5.00%	26,594	26,594	-
1960	GA Misc. Equip	82,856	47,728	35,129	210,926	(105,463)	140,592	5.00	20.00%	28,118	28,118	(0)
1960A	GA Misc. Equip	59,693	0	59,693	-	-	59,693	10.00	10.00%	5,969	5,969	(0)
1980	System Supervisor Equipment	742,499	538,441	204,058	44,636	(22,318)	226,376	10.00	10.00%	22,638	22,638	-
1980A	System Supervisor Equipment	3,067	3,067	-	-	-	-	5.00	20.00%	-	-	-
1995	Contributions & Grants	(7,466,187)	(644,013)	(6,822,173)	(377,924)	188,962	(7,011,135)	30.00	3.33%	(233,705)	(233,705)	-
	Total	85,740,346	9,814,099	75,926,246	6,274,022	(3,137,284)	79,062,984			3,559,140	3,559,140	(0)

Appendix 2-CF
Depreciation and Amortization Expense
2012
Port Colborne

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Depreciation Expense per Fixed Asset Continuity Schedule (i)	Variance (m) = (h) - (i)
1806	Land Rights	66,032	0	66,032	8,000	(4,000)	70,032	40.00	2.50%	1,751	1,751	-
1808	Buildings	241,652	-	241,652	-	-	241,652	50.00	2.00%	4,833	4,833	0
1820	Substation Equipment	5,363,100	559	5,362,541	440,084	(220,042)	5,582,583	33.33	3.00%	167,494	167,494	-
1830	Poles, Towers & Fixtures	2,512,219	0	2,512,219	484,443	(242,221)	2,754,440	25.00	4.00%	110,178	110,178	-
1835	OH Conductors & Devices	3,066,515	321	3,066,194	289,947	(144,974)	3,211,167	33.33	3.00%	96,345	96,345	-
1840	UG Conduit	156,361	-	156,361	109,511	(54,756)	211,117	50.00	2.00%	4,222	4,222	-
1845	UG Conductors & Devices	1,043,904	108	1,043,797	69,629	(34,815)	1,078,612	33.33	3.00%	32,362	32,362	-
1850	Line Transformers	1,961,749	203	1,961,546	145,034	(72,517)	2,034,063	33.33	3.00%	61,028	61,028	-
1855	Services (OH & UG)	1,247,079	139	1,246,940	288,821	(144,410)	1,391,350	33.33	3.00%	41,745	41,745	-
1860	Meters	527,040	(583,818)	1,110,858	69,007	(34,504)	1,145,362	25.00	4.00%	45,814	45,814	-
1865	Other Install on Cust Prem	64,060	(6,504)	70,564	-	-	70,564	10.00	10.00%	7,056	7,056	-
1908	Buildings & Fixtures	140,288	-	140,288	-	-	140,288	50.00	2.00%	2,806	2,806	0
1915	Office Furniture & Equipment 10yr	22,668	3,813	18,855	-	-	18,855	10.00	10.00%	1,886	1,886	0
1920	Computer - Hardware	93,594	20,441	73,152	-	-	73,152	5.00	20.00%	14,630	14,630	-
1925	Computer Software	153,073	(18,550)	171,623	-	-	171,623	10.00	10.00%	17,162	17,162	-
1935	Stores Equipment	486	203	284	-	-	284	10.00	10.00%	28	28	-
1940	Tools, Shop & Garage Equipment	14,089	7,609	6,480	-	-	6,480	10.00	10.00%	648	648	-
1955	Communications Equipment	111,984	83,364	28,621	3,129	(1,565)	30,185	20.00	5.00%	1,509	1,509	-
1980	System Supervisor Equipment	30,562	(0)	30,562	39,242	(19,621)	50,183	10.00	10.00%	5,018	5,018	-
1995	Contributions & Grants	(1,885,767)	(275,239)	(1,610,528)	(139,110)	69,555	(1,680,083)	30.00	3.33%	(56,003)	(56,003)	-
	Total	14,930,688	(767,351)	15,698,040	1,807,739	(903,870)	16,601,909			560,513	560,513	0

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year 2013 MIFRS FE and EOP

Account	Description	Opening NBV as at Jan 1, 2013 5 (a)	MIFRS Additions (d)	Average Remaining Life of Opening NBV 4 (i)	Years (new additions only) 3 (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions 1 (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per MIFRS Appendix 2-B Fixed Assets, Column K	Variance 2 (m) = (k) - (l)	2013 Depreciation Expense per CGAAP Appendix 2-B Fixed Assets, Column K	Variance MIFRS less CGAAP
1608	Franchises & Consents	$ 120,941	$ -	31.00	40.00	2.50%	$ 3,901	$ -	$ 3,901	$ 3,901	-$ 0	$ 3,901	$ 0
1805	Land	$ 189,861	$ -			0.00%	$ -	$ -	$ -	$ -	$ -		$ -
1806	Land Rights	$ 138,974	$ 26,052	33.48	40.00	2.50%	$ 4,151	$ 326	$ 4,477	$ 4,477	-$ 0	$ 4,477	$ -
1808	Buildings	$ 2,832,874	$ 20,000	37.69	50.00	2.00%	$ 75,164	$ 200	$ 75,364	$ 75,364	$ 0	$ 75,414	-$ 50
1820	Substation Equipment	$ 4,409,785	$ 396,923	33.85	40.00	2.50%	$ 130,285	$ 4,962	$ 135,246	$ 135,246	$ 0	$ 201,333	-$ 66,087
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -		$ -		$ -
1830	Poles, Towers & Fixtures	$ 9,114,696	$ 1,024,625	35.51	45.00	2.22%	$ 256,701	$ 11,385	$ 268,085	$ 268,085	$ 0	$ 659,644	-$ 391,559
1835	OH Conductors & Devices	$ 14,059,437	$ 966,848	35.50	45.00	2.22%	$ 396,005	$ 10,743	$ 406,748	$ 406,747	$ 0	$ 608,095	-$ 201,347
1840	UG Conduit	$ 547,174	$ 1,718	35.66	50.00	2.00%	$ 15,342	$ 17	$ 15,360	$ 15,360	$ 0	$ 15,364	-$ 4
1845	UG Conductors & Devices	$ 4,722,389	$ 145,236	32.00	40.00	2.50%	$ 147,580	$ 1,815	$ 149,396	$ 149,396	$ 0	$ 187,175	-$ 37,779
1850	Line Transformers	$ 6,190,795	$ 381,580	29.64	40.00	2.50%	$ 208,845	$ 4,770	$ 213,615	$ 213,615	$ 0	$ 302,599	-$ 88,985
1855	Services (OH & UG)	$ 5,493,953	$ 586,397	25.73	40.00	2.50%	$ 213,489	$ 7,330	$ 220,819	$ 220,819	$ 0	$ 237,343	-$ 16,524
1860	Meters	$ 1,268,877	$ 113,754	19.81	30.00	3.33%	$ 64,050	$ 1,896	$ 65,946	$ 65,946	-$ 0	-$ 23,376	$ 89,322
1865	D Other Install on Cust Prem	$ 32,391		7.46	10.00	10.00%	$ 4,341	$ -	$ 4,341	$ 4,341	$ 0	$ 84,790	-$ 80,449
1861	Smart Meters	$ 2,526,805		12.15	15.00	6.67%	$ 208,029	$ -	$ 208,029	$ 208,030	-$ 1	$ 208,030	-$ 0
1861	Smart Meters/Communication Systems					0.00%	$ -	$ -	$ -		$ -	$ 4,341	-$ 4,341
1908	Buildings & Fixtures	$ 682,098	$ -	40.01	50.00	2.00%	$ 17,047	$ -	$ 17,047	$ 17,047	$ 0	$ 17,047	$ 0
1910	Leasehold Improvements	$ 282,921	$ 53,000	3.38	5.00	20.00%	$ 83,764	$ 5,300	$ 89,064	$ 89,063	$ 1	$ 89,063	$ -
1915	Office Furniture & Equipment 10yr	$ 85,121	$ 2,500	3.01	10.00	10.00%	$ 28,249	$ 125	$ 28,374	$ 28,373	$ 0	$ 28,405	-$ 32
1920	Computer - Hardware	$ 1,165,540	$ 101,163	2.99	5.00	20.00%	$ 389,305	$ 10,116	$ 399,421	$ 399,420	$ 1	$ 401,110	-$ 1,690
1925	Computer Software	$ 2,842,204	$ 558,053	4.90	10.00	10.00%	$ 580,018	$ 27,903	$ 607,921	$ 607,926	-$ 5	$ 547,984	$ 59,942
1925	Computer Software Smart Meters	$ 321,050		8.53	10.00	10.00%	$ 37,654	$ -	$ 37,654	$ 37,654	$ 0	$ 37,654	$ -
1930	Transportation Equipment	$ 1,747,082	$ 390,000	5.18	10.00	10.00%	$ 337,587	$ 19,500	$ 357,087	$ 357,086	$ 1	$ 357,086	$ -
1935	Stores Equipment	$ 11,989	$ -	2.59	10.00	10.00%	$ 4,628	$ -	$ 4,628	$ 4,628	$ 0	$ 4,628	-$ 0
1940	Tools, Shop & Garage Equipment	$ 57,925	$ 26,000	5.05	10.00	10.00%	$ 11,469	$ 1,300	$ 12,769	$ 12,769	-$ 0	$ 12,986	-$ 217
1945	Measurement & Testing Equipment	$ 79,592	$ 22,000	3.89	10.00	10.00%	$ 20,475	$ 1,100	$ 21,575	$ 21,575	$ 0	$ 21,793	-$ 218
1950	Power operated Equipment	$ 16,432	$ -	6.81	10.00	10.00%	$ 2,414	$ -	$ 2,414	$ 2,414	$ 0	$ 2,414	-$ 0
1955	Communications Equipment	$ 522,381	$ 18,000	5.81	10.00	10.00%	$ 89,956	$ 900	$ 90,856	$ 90,856	-$ 0	$ 33,939	$ 56,917
1960	GA Misc. Equip	$ 232,385	$ 182,671	4.21	5.00	20.00%	$ 55,145	$ 18,267	$ 73,412	$ 73,411	$ 0	$ 76,463	-$ 3,051
1980	System Supervisor Equipment	$ 115,866	$ 55,792	12.74	20.00	5.00%	$ 9,092	$ 1,395	$ 10,486	$ 10,486	$ 0	$ 24,085	-$ 13,599
1995	Contributions & Grants	-$ 6,119,696	-$ 285,000	25.45	33.30	3.00%	-$ 240,495	-$ 4,279	-$ 244,775	-$ 244,775	$ 0	-$ 244,775	$ -
						0.00%	$ -	$ -	$ -		$ -		$ -
	Total	$ 53,691,841	$ 4,787,314				$ 3,154,189	$ 125,070	$ 3,279,258	$ 3,279,260	-$ 2	$ 3,979,012	-$ 699,752

Less NBV Smart Meters	$ 2,892,731	**Less depreciation expense on pre 1999 CIAC**	$ 25,505	$ 25,505
Opening NBV per Continuity Schedule	$ 50,799,110	**Less depreciation expense of allocated assets**	$ 1,017,518	$ 957,472
		Total Depreciation Expense	$ 2,236,237	$ 2,996,035

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013

Year **2013** **MIFRS** **PORT COLBORNE**

Account	Description	Opening NBV as at Jan 1, 2013 5 (a)	MIFRS Additions (d)	Average Remaining Life of Opening NBV 4 (i)	Years (new additions only) 3 (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions 1 (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per MIFRS Appendix 2-B Fixed Assets, Column K	Variance 2 (m) = (k) - (l)	2013 Depreciation Expense per CGAAP Appendix 2-B Fixed Assets, Column K	Variance MIFRS less CGAAP
1806	Land Rights	$ 66,415	$ 50,000	35.88	40.00	2.50%	$ 1,851	$ 625	$ 2,476	$ 2,476	$ 0	$ 2,476	$ -
1808	Buildings	$ 196,657	$ -	40.69	50.00	2.00%	$ 4,833	$ -	$ 4,833	$ 4,833	-$ 0	$ 4,833	$ -
1820	Substation Equipment	$ 4,996,137	$ 373,489	41.72	40.00	2.50%	$ 119,754	$ 4,669	$ 124,422	$ 124,422	$ 0	$ 180,900	-$ 56,478
1830	Poles, Towers & Fixtures	$ 2,360,180	$ 350,334	39.39	45.00	2.22%	$ 59,914	$ 3,893	$ 63,806	$ 63,806	$ 0	$ 128,377	-$ 64,571
1835	OH Conductors & Devices	$ 2,779,129	$ 234,869	38.81	45.00	2.22%	$ 71,607	$ 2,610	$ 74,217	$ 74,217	$ 0	$ 104,973	-$ 30,757
1840	UG Conduit	$ 251,549	$ 103,943	47.31	50.00	2.00%	$ 5,317	$ 1,039	$ 6,357	$ 6,357	-$ 0	$ 6,580	-$ 223
1845	UG Conductors & Devices	$ 948,458	$ 81,113	34.63	40.00	2.50%	$ 27,387	$ 1,014	$ 28,401	$ 28,401	-$ 0	$ 34,884	-$ 6,483
1850	Line Transformers	$ 1,728,442	$ 120,000	33.69	40.00	2.50%	$ 51,297	$ 1,500	$ 52,797	$ 52,797	-$ 0	$ 65,390	-$ 12,593
1855	Services (OH & UG)	$ 1,367,739	$ 264,590	35.50	40.00	2.50%	$ 38,526	$ 3,307	$ 41,834	$ 41,834	-$ 0	$ 50,898	-$ 9,064
1860	Meters	$ 440,539	$ 74,567	14.70	30.00	3.33%	$ 29,961	$ 1,243	$ 31,204	$ 31,204	-$ 0	$ 31,087	$ 117
1865	D Other Install on Cust Prem	$ 65,239		7.17	10.00	10.00%	$ 9,098	$ -	$ 9,098	$ 9,098	-$ 0	$ 9,098	$ -
1861	Smart Meters	$ 1,322,183		12.06	15.00	6.67%	$ 109,647	$ -	$ 109,647	$ 109,647	$ 0	$ 109,647	$ 0
1908	Buildings & Fixtures	$ 116,827		41.64	50.00	2.00%	$ 2,806	$ -	$ 2,806	$ 2,806	$ 0	$ 2,806	$ -
1915	Office Furniture & Equipment 10yr	$ 13,725		4.80	10.00	10.00%	$ 2,861	$ -	$ 2,861	$ 2,861	$ 0	$ 1,886	$ 976
1920	Computer - Hardware	$ 21,220		3.22	5.00	20.00%	$ 6,599	$ -	$ 6,599	$ 6,599	$ 0	$ 7,575	-$ 976
1925	Computer Software	$ 45,588		2.66	5.00	20.00%	$ 17,162	$ -	$ 17,162	$ 17,162	-$ 0	$ 17,162	$ -
1925	Computer Software - Smart meters	$ 144,880		8.63	10.00	10.00%	$ 16,795	$ -	$ 16,795	$ 16,795	$ 0	$ 16,795	$ -
1940	Tools, Shop & Garage Equipment	$ 972		1.50	10.00	10.00%	$ 648	$ -	$ 648	$ 648	$ -	$ 648	$ -
1955	Communications Equipment	$ 10,266		2.00	10.00	10.00%	$ 5,127	$ -	$ 5,127	$ 5,127	$ 0	$ 1,588	$ 3,539
1980	System Supervisor Equipment	$ 49,523	$ 38,356	17.71	20.00	5.00%	$ 2,796	$ 959	$ 3,755	$ 3,755	-$ 0	$ 9,310	-$ 5,555
1995	Contributions & Grants	-$ 1,832,543	-$ 140,000	30.49	33.30	3.00%	-$ 60,097	-$ 2,102	-$ 62,199	-$ 62,199	-$ 0	-$ 62,199	$ -
						0.00%	$ -	$ -	$ -		$ -		$ -
	Total	$ 15,093,127	$ 1,551,262				$ 523,890	$ 18,756	$ 542,646	$ 542,646	$ 1	$ 724,713	-$ 182,067

Less NBV Smart Meters	$ 1,486,025	**Add depreciation expense of acquired assets**	$ 464,613	$ 464,613
Add NBV of Lease Assets Acquired	$ 2,505,544	**Add depreciation expense of allocated assets**	$ 253,915	$ 237,574
Opening NBV per Continuity Schedule	$ 16,112,645	**Total Depreciation Expense**	$ 1,261,174	$ 1,426,900

Appendix 2-D
Overhead Expense - FE and EOP

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or an alternate accounting standard.

	(A) 1	(B)	(C)	(D)	(E) 1	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year**	**Dollar Impact on PP&E Bridge Year**	**Dollar Impact on PP&E Test Year**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits				$ -	$ -		no change
costs of site preparation				$ -	$ -		no change
initial delivery and handling costs				$ -	$ -		no change
costs of testing whether the asset is functioning properly				$ -	$ -		no change
professional fees				$ -	$ -		no change
				$ -	$ -		
costs of opening a new facility				$ -	$ -		no change
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		no change
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		no change
administration and other general overhead costs - not included in labour rates offset by				$ -	$ -		
vehicle depreciation included in labour rates			-$ 36,927	-$ 36,927	-$ 36,927	N and Y	Considered non-attributable and not included in labour rates
				$ -	$ -		offset by vehicle depreciation that is attibutable
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	-$ 36,927	-$ 36,927	-$ 36,927		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

	(A) 1	(B)	(C)	(D)	(E) 1	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year**	**Dollar Impact on OM&A Bridge Year**	**Dollar Impact on OM&A Test Year**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits				$ -	$ -		no change
costs of site preparation				$ -	$ -		no change
initial delivery and handling costs				$ -	$ -		no change
costs of testing whether the asset is functioning properly				$ -	$ -		no change
professional fees				$ -	$ -		no change
costs of opening a new facility				$ -	$ -		no change
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		no change
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		no change
administration and other general overhead costs			$ 797,360	$ 797,360	$ 797,360	N	Considered non-attributable
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ 797,360	$ 797,360	$ 797,360		

Notes:

1 If the applicant chooses to adopt IFRS or an alternate accounting standard for financial reporting purposes in 2013, the applicant does not need to complete Columns A, E. If the applicant adopts IFRS or an alternate accounting standard for financial reporting purposes in 2012, the applicant must complete all columns.

Appendix 2-D
Overhead Expense - PC

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that are currently capitalized on self-constructed assets under MIFRS or an alternate accounting standard.

	(A) 1	(B)	(C)	(D)	(E) 1	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year**	**Dollar Impact on PP&E Bridge Year**	**Dollar Impact on PP&E Test Year**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits				$ -	$ -		no change
costs of site preparation				$ -	$ -		no change
initial delivery and handling costs				$ -	$ -		no change
costs of testing whether the asset is functioning properly				$ -	$ -		no change
professional fees				$ -	$ -		no change
				$ -	$ -		
costs of opening a new facility				$ -	$ -		no change
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		no change
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		no change
administration and other general overhead costs - not included in labour rates offset by				$ -	$ -		
vehicle depreciation included in labour rates			$ 8,339	$ 8,339	$ 8,339	N and Y	Considered non-attributable and not included in labour rates
				$ -	$ -		offset by vehicle depreciation that is attibutable
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ 8,339	$ 8,339	$ 8,339		

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under MIFRS or an alternate accounting standard and are included in OM&A.

	(A) 1	(B)	(C)	(D)	(E) 1	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year**	**Dollar Impact on OM&A Bridge Year**	**Dollar Impact on OM&A Test Year**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are not allowed to be capitalized under MIFRS or an alternate accounting standard given limitations on capitalized overhead**
employee benefits				$ -	$ -		no change
costs of site preparation				$ -	$ -		no change
initial delivery and handling costs				$ -	$ -		no change
costs of testing whether the asset is functioning properly				$ -	$ -		no change
professional fees				$ -	$ -		no change
costs of opening a new facility				$ -	$ -		no change
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		no change
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		no change
administration and other general overhead costs			$ 343,954	$ 343,954	$ 343,954	N	Considered non-attributable
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ -	$ -	$ 343,954	$ 343,954	$ 343,954		

Notes:

1 If the applicant chooses to adopt IFRS or an alternate accounting standard for financial reporting purposes in 2013, the applicant does not need to complete Columns A, E. If the applicant adopts IFRS or an alternate accounting standard for financial reporting purposes in 2012, the applicant must complete all columns.

Appendix 2-H
Regulatory Cost Schedule - FE and EOP

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 62,689	$ 67,451	$ 66,800	-0.97%	$ 66,800	0.00%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 1,709	$ 1,087	$ 1,400	28.85%	$ 1,400	0.00%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 1,410	$ 1,416	$ 1,400	-1.12%	$ 1,400	0.00%
4	Expert Witness costs for regulatory matters				$ -	$ -	$ -		$ -	
5	Legal costs for regulatory matters	5655		On-Going	$ 79,268	$ 1,500	$ 23,768	1484.53%	$ 22,848	-3.87%
6	Consultants' costs for regulatory matters	5655		On-Going	$ 5,195	$ 8,551	$ 18,891	120.91%	$ 16,180	-14.35%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 42,977	$ 44,036	$ 60,230	36.78%	$ 61,529	2.16%
8	Operating expenses associated with other resources allocated to regulatory matters [1]				$ -	$ -	$ -		$ -	
9	Other regulatory agency fees or assessments	5655		On-Going	$ 4,005	$ 2,510	$ 4,800	91.26%	$ 4,800	0.00%
10	Any other costs for regulatory matters (please define)				$ -	$ -	$ -		$ -	
11	Intervenor costs	5655		On-Going	$ -	$ 36,684	$ 16,666	-54.57%	$ 16,666	0.00%
12	Sub-total - Ongoing Costs [3]		$ -		$ 197,252	$ 163,234	$ 193,955	18.82%	$ 191,623	-1.20%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 197,252	$ 163,234	$ 193,955	18.82%	$ 191,623	-1.20%

[1] Please identify the resources involved.
[2] Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
[3] Sum of all ongoing costs identified in rows 1 to 11 inclusive.
[4] Sum of all one-time costs identified in rows 1 to 11 inclusive.

Please fill out the following table for all one-time costs related to this cost of service application

		Historical Year(s)	2012 Bridge Year	2013 Test Year
4	Expert Witness costs for regulatory matters	0	$ -	$ -
5	Legal costs for regulatory matters	0	$ -	$ 22,848
6	Consultants' costs for regulatory matters	0	$ -	$ 16,180
7	Operating expenses associated with staff resources allocated to regulatory matters	0	$ -	$ 61,529
8	Operating expenses associated with other resources allocated to regulatory matters [1]	0	$ -	$ -
11	Intervenor costs	0	$ -	$ 16,666

NOTE: Regulatory Cost Category 5, 6 and 11 for 2013 Test Year represent one quarter of total expected costs for this rate application.

Appendix 2-H
Regulatory Cost Schedule - PC

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 33,460	$ 36,320	$ 35,750	-1.57%	$ 35,750	0.00%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 870	$ 585	$ 700	19.64%	$ 700	0.00%
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 742	$ 762	$ 750	-1.62%	$ 750	0.00%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		On-Going	$ 154,085	$ 750	$ 11,784	1471.20%	$ 11,424	-3.05%
6	Consultants' costs for regulatory matters	5655		On-Going	$ 5,320	$ 6,249	$ 11,508	84.17%	$ 8,793	-23.59%
7	Operating expenses associated with staff resources allocated to regulatory matters	5655		On-Going	$ 33,903	$ 44,497	$ 59,270	33.20%	$ 60,821	2.62%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655		On-Going	$ 726	$ 1,340	$ 2,500	86.54%	$ 2,496	-0.16%
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Going		$ 43,020	$ 8,333	-80.63%	$ 8,333	0.00%
12	Sub-total - Ongoing Costs [3]		$ -		$ 229,107	$ 133,523	$ 130,595	-2.19%	$ 129,067	-1.17%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 229,107	$ 133,523	$ 130,595	-2.19%	$ 129,067	-1.17%

[1] Please identify the resources involved.
[2] Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
[3] Sum of all ongoing costs identified in rows 1 to 11 inclusive.
[4] Sum of all one-time costs identified in rows 1 to 11 inclusive.

Please fill out the following table for all one-time costs related to this cost of service application

		Historical Year(s)	2012 Bridge Year	2013 Test Year
4	Expert Witness costs for regulatory matters	0	$ -	$ -
5	Legal costs for regulatory matters	0	$ -	$ 11,424
6	Consultants' costs for regulatory matters	0	$ -	$ 8,793
7	Operating expenses associated with staff resources allocated to regulatory matters	0	$ -	$ 60,821
8	Operating expenses associated with other resources allocated to regulatory matters [1]	0	$ -	$ -
11	Intervenor costs	0	$ -	$ 8,333

NOTE: Regulatory Cost Category 5, 6 and 11 for 2013 Test Year represent one quarter of total expected costs for this rate application.

(OEB)

6. Ref: E1/T1/S1

The Board's Conservation and Demand Management ("CDM") Guidelines for Electricity Distributors (EB-2012-0003) at page 3 notes that: "At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism rate application, if the balance is deemed significant by the applicant." Board staff acknowledges that the final, verified results for CNPI's 2011 OPA-Contracted Province-Wide CDM programs are not currently available.

a) Does CNPI plan to update its evidence to indentify and/or seek disposition of variances between the final results of its 2011 CDM programs and the CDM savings reflected in CNPI's 2011 rates in this proceeding after it has received the final results from the OPA?

b) What is CNPI's plan for disposing of its LRAMVA in future applications?

RESPONSE:

a) CNPI's 2011 rates are premised on the 2009 EDR; there is no CDM forecast reflected in the 2011 rates. CNPI will seek to clear its LRAMVA at a later date.

b) CNPI plans to dispose of its LRAMVA in a future application.

(VECC)

1. General

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

34. Reference: Exhibit 2, Tab 2, Schedule 1

a) CNPI's Conditions of service (posted on the Fort Erie Website) state that they were last revised in July 2008. Have the Conditions of Service for all service territories been updated for the Board's revised low income rules that came into effect in October 2011?

b) If yes, please indicate how and where these changes are communicated to customers.

RESPONSE:

a) CNPI is currently revising its Conditions of Service, which should be complete by the end of the fourth quarter 2012. The current Conditions of Service found on CNPI's website require updating to meet the requirements of the Board's revised low income rules that came into effect in October 2011. However, CNPI has ensured that all internal procedures conform to the Distribution System Code.

b) These changes have been communicated to customers through participation in the LEAP program, brochures, and direct communication with our Customer Service Representatives.

1. General

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

(VECC)

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

35. Reference: Exhibit 4, Tab 1, Schedule 1, pages 1
Schedule 2, pages 1 - 5

a) CNPI states that is uses the Bank of Canada's target inflationary for 2012 of 2%. Please provide the most current annual inflation rate for 2012.

RESPONSE:

a) The Bank of Canada's inflation rate for the six months ended June 30, 2012 was 1.5%. The annual inflation rates for 2011 and 2010 were 2.3% and 2.4%, respectively.

(OEB)

General

Issue 1.3
Is service quality, based on the Board specified performance indicators, acceptable?

No Interrogatories Posed

(OEB)

General

Issue 1.4
Is the proposal to align the rate year with CNPI's fiscal year, and for rates effective January 1, 2013 appropriate?

No Interrogatories Posed

Canadian Niagara Power Inc.

EB-2012-0112

Response to Rate Base Interrogatories

2. Rate Base

2.1
Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

(OEB)

Rate Base

Issue 2.1
Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

7. Ref: E2/T1/S3 – Rate Base Variance

On page 1 CNPI – FE/EOP shows a gross downward adjustment on Gross Fixed Assets of $1.4M for 2009 through 2013 test year and an upward adjustment of accumulated depreciation of $286,946 in 2009, $329,457 in 2010, $371,968 in 2011, $414,478 in the 2012 bridge year and $456,989 in the 2013 test year. Please explain the reasons for these adjustments to rate base.

RESPONSE:

In 2003 when CNPI acquired Eastern Ontario Power (formerly Granite Power Distribution Corporation), the fixed assets were written up to fair market value ("FMV") by approximately $1.4 million. The FMV write up has been excluded from rate base for rate making purposes. This amount is being amortized over the useful life of the assets acquired. This adjustment, consistent with CNPI's previous cost of service applications, illustrates the exclusion of the net book value of the write-up.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

1. **Ref: Exhibit 2, Tab 1, Schedule 3**

Please explain the gross write up and accumulated depreciation write up shown in this schedule. What do these write ups relate to?

RESPONSE:

Please see the response to Board Staff interrogatory number #7.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

2. Ref: Exhibit 2, Tab 1, Schedule 5, page 5

a) Please provide a version of the continuity schedule for 2013 that has smart meters (and related assets) included in the opening 2013 balance and has stranded meters removed from the opening 2013 balance. Please also ensure that the appropriate adjustments are made to the opening balances for accumulated depreciation.

b) Please show the calculation of the smart meter related accumulated depreciation expenses shown in the table.

RESPONSE:

a) Please refer to page 3 below.

b) The CNPI – FE-EOP Smart Meter accumulated depreciation values were taken from Exhibit 10 of the rate application. Please refer to Table 2.1.2 below for tie-out. For the actual calculations, please refer back to the Exhibit 10 referenced cells noted in Table 2.1.2 below.

Table 2.1.2: CNPI – FE/EOP Smart Meter Accumulated Depreciation Tie-out

		Per Exhibit 2	Per Exhibit 10					
OEB Acct #	**Account Description**	**FE/EOP**	**FE**		**EOP**		**Total**	**Difference**
1860	D Meters	(593,644)	(467,108)	**A**	(126,535)	**E**	(593,644)	-
1865	D Other Install on Cust Prem	(11,014)	(8,515)	**B**	(2,498)	**F**	(11,014)	-
1920	GA Comp Hardware	(19,742)	(19,391)	**C**	(351)	**G**	(19,742)	-
1925	GA Comp Software	(55,485)	(39,348)	**D**	(16,136)	**H**	(55,485)	-
	Total	**(679,884)**	**(534,363)**		**(145,522)**		**(679,884)**	**-**

Notes:

A Cell S31 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S2
B Cell S107 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S2
C Cell S50 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S2
D Cell S69 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S2
E Cell S31 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S4
F Cell S107 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S4
G Cell S50 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S4
H Cell S69 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S4

CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2013

CO. #0020 FE AND EOP Distribution

		COST					ACCUMULATED DEPRECIATION					NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1608	Franchises & Consents	**156,053**	-	**156,053**	**-**	**156,053**	**(35,112)**	(3,901)	**(39,013)**	**-**	**(39,013)**	**117,040**
1805	D Land	**189,861**	-	**189,861**	**-**	**189,861**	**-**	-	**-**	**-**	**-**	**189,861**
1806	D Land Rights	**215,966**	26,052	**242,018**	**-**	**242,018**	**(76,993)**	(4,477)	**(81,469)**	**-**	**(81,469)**	**160,549**
1808	D Bldgs & Fixtures	**3,758,190**	25,042	**3,783,232**	**-**	**3,783,232**	**(925,316)**	(75,414)	**(1,000,730)**	**-**	**(1,000,730)**	**2,782,502**
1820	D Station Equipment < 50KV	**6,576,742**	468,736	**7,045,478**	**-**	**7,045,478**	**(2,166,958)**	(201,333)	**(2,368,291)**	**-**	**(2,368,291)**	**4,677,187**
1830	D Poles,Towers&Fixtures	**17,269,751**	1,225,597	**18,495,347**	**-**	**18,495,347**	**(8,155,055)**	(659,644)	**(8,814,699)**	**-**	**(8,814,699)**	**9,680,648**
1835	D OH Cond & Devices	**21,337,432**	1,146,367	**22,483,799**	**-**	**22,483,799**	**(7,277,995)**	(608,095)	**(7,886,090)**	**-**	**(7,886,090)**	**14,597,709**
1840	D UG Conduit & Manholes	**767,122**	2,151	**769,273**	**-**	**769,273**	**(219,948)**	(15,364)	**(235,312)**	**-**	**(235,312)**	**533,962**
1845	D UG Cond & Devices	**6,214,594**	171,688	**6,386,282**	**-**	**6,386,282**	**(1,492,205)**	(187,175)	**(1,679,380)**	**-**	**(1,679,380)**	**4,706,902**
1850	D Line Transformers	**10,775,596**	459,916	**11,235,511**	**-**	**11,235,511**	**(4,584,801)**	(302,599)	**(4,887,400)**	**-**	**(4,887,400)**	**6,348,111**
1855	D Services	**7,946,600**	694,653	**8,641,252**	**-**	**8,641,252**	**(2,452,646)**	(237,343)	**(2,689,990)**	**-**	**(2,689,990)**	**5,951,263**
1860	D Meters	**3,959,931**	134,303	**4,094,234**	**-**	**4,094,234**	**(978,983)**	(269,444)	**(1,248,427)**	**-**	**(1,248,427)**	**2,845,807**
1865	D Other Install on Cust Prem	**43,405**	-	**43,405**	**-**	**43,405**	**(11,014)**	(4,341)	**(15,354)**	**-**	**(15,354)**	**28,051**
1875	D St Lites & Signal Systems	**-**	-	**-**	**-**	**-**	**-**	-	**-**	**-**	**-**	**-**
1908	GA Bldgs & Fixtures	**852,372**	-	**852,372**	**-**	**852,372**	**(170,274)**	(17,047)	**(187,322)**	**-**	**(187,322)**	**665,050**
1910	GA Leasehold Improvements	**418,814**	53,000	**471,814**	**-**	**471,814**	**(135,893)**	(89,063)	**(224,956)**	**-**	**(224,956)**	**246,858**
1915	GA Office Furn & Equipment	**1,335,241**	3,130	**1,338,372**	**(597,878)**	**740,494**	**(1,250,120)**	(28,405)	**(1,278,525)**	**574,076**	**(704,449)**	**36,045**
1920	GA Comp Hardware	**3,186,697**	118,061	**3,304,758**	**(2,447,804)**	**856,953**	**(2,021,157)**	(401,110)	**(2,422,267)**	**1,790,031**	**(632,236)**	**224,717**
1925	GA Comp Software	**8,529,849**	558,053	**9,087,902**	**(5,880,745)**	**3,207,157**	**(5,366,594)**	(585,637)	**(5,952,231)**	**3,594,211**	**(2,358,020)**	**849,136**
1930	GA Transportation Equipment	**3,939,281**	390,000	**4,329,281**	**(1,453,735)**	**2,875,546**	**(2,192,199)**	(357,086)	**(2,549,285)**	**877,794**	**(1,671,491)**	**1,204,055**
1935	GA Stores Equip	**166,152**	-	**166,152**	**(76,430)**	**89,722**	**(154,163)**	(4,628)	**(158,790)**	**73,044**	**(85,747)**	**3,975**
1940	GA tools,shop&garage equip	**698,297**	30,343	**728,640**	**(326,831)**	**401,809**	**(640,372)**	(12,986)	**(653,359)**	**294,959**	**(358,400)**	**43,409**
1945	GA measure&test equip	**499,998**	26,355	**526,354**	**(223,957)**	**302,397**	**(420,406)**	(21,793)	**(442,199)**	**195,235**	**(246,964)**	**55,432**
1950	GA power op equip	**109,339**	-	**109,339**	**-**	**109,339**	**(92,907)**	(2,414)	**(95,321)**	**-**	**(95,321)**	**14,019**
1955	GA Comm Equipment	**938,536**	21,007	**959,542**	**(424,845)**	**534,698**	**(416,155)**	(33,939)	**(450,093)**	**194,121**	**(255,972)**	**278,726**
1960	GA Misc. Equip	**353,476**	213,183	**566,659**	**(259,025)**	**307,634**	**(121,091)**	(76,463)	**(197,553)**	**89,733**	**(107,820)**	**199,814**
1980	GA System Supv Equip	**790,202**	65,111	**855,313**	**(392,437)**	**462,876**	**(674,336)**	(24,085)	**(698,421)**	**320,267**	**(378,154)**	**84,721**
1995	Contributions & Grants	**(7,728,869)**	(285,000)	**(8,013,869)**	**-**	**(8,013,869)**	**1,664,654**	244,775	**1,909,429**	**-**	**1,909,429**	**(6,104,441)**
	Total before AUC	**93,300,627**	5,547,747	**98,848,374**	(12,083,686)	**86,764,688**	**(40,368,039)**	(3,979,012)	**(44,347,051)**	8,003,471	**(36,343,580)**	**50,421,108**
2055	Asset Under Construction	**2,072,053**	129,644	**2,201,697**	**-**	**2,201,697**	**-**	-	**-**	**-**	**-**	**2,201,697**
	Total after AUC	**95,372,680**	**5,677,391**	**101,050,071**	**(12,083,686)**	**88,966,385**	**(40,368,039)**	**(3,979,012)**	**(44,347,051)**	**8,003,471**	**(36,343,580)**	**52,622,805**

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

3. Ref: Exhibit 2, Tab 1, Schedule 1, page 1
Exhibit 2, Tab 3, Schedule 1, pages 14 and 27

The first reference states at line 16 that the Fort Erie system has "fifteen step down ratio banks". The second reference on page 14 presents a table listing 16 ratio banks for Fort Erie and page 27 of that exhibit shows a summary table listing 11 ratio banks for Fort Erie. Please advise which of these is correct.

RESPONSE:

The Fort Erie system has 20 Ratio Banks, 12 three-phase and 8 single phase.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

4. Ref: Exhibit 1, Tab 2, Schedule 1, page 13
Exhibit 2, Tab 1, Schedule 2, page 5
Exhibit 2, Tab 3, Schedule 1, pages 23 and 27

The first reference states at line 5 that the Port Colborne distribution system has 13 ratio banks while the second reference states at line 3 that the system has 12 ratio banks. The third reference at page 23 shows a table listing 14 ratio banks for Port Colborne and at page 27 a table listing 8 ratio banks for Port Colborne. Please advise which of these is correct.

RESPONSE:

The Port Colborne Distribution System has 12 Ratio Banks.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

5. Ref: EB-2008-0223 Energy Probe IR-FE #3

In CNPI's previous cost of service application in 2008, it was asked about the prevalence of ratio banks on its systems and its plans to reduce those numbers. Please describe the actions taken since 2008 to achieve the objective of limiting the number of ratio banks on CNPI distribution systems.

RESPONSE:

CNPI's ongoing voltage conversion efforts in the Ridgeway area have resulted in decreased loading on 4.8 kV delta-connected ratio banks in that area. One such ratio bank was retired from service in 2012 year-to-date, and more banks will be retired over the next few years as loads continue to be converted from 4.8 kV delta to 8.3 kV wye.

One additional ratio bank was added in 2012 year-to-date in the Stevensville area to improve system reliability in that area. The Stevensville area is served at 4.16 kV, and is therefore unique and electrically isolated from the rest of CNP-FE's distribution systems. As described in the response to IR# 7, this option was the most cost-effective solution for the area. While CNPI's overall long-term goal is to reduce the number of ratio banks on its system, there are situations where ratio banks provide an economic solution for electricity distribution in rural areas with low-density loads.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

6. Ref: Exhibit 2, Tab 1, Schedule 1, page 2

Line 30 on page 2 of the exhibit references efforts to convert loads supplied by ratio banks to the 8.3 kV system. Please describe the progress made to date and future plans to achieve this objective.

RESPONSE:

Since 2008, CNPI has spent $1,094,000 on voltage conversion projects and 832 customers have been converted from the 4.8 kV delta system to 8.3 kV grounded wye system.

CNPI will convert loads from the 4.8 kV delta system to the 8.3 kV grounded wye system in the future years. Ratio banks will be removed from the system as the loads supplied by these ratio banks are converted.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

7. Ref: Exhibit 2, Tab 1, Schedule 1, page 3
Exhibit 2, Tab 2, Schedule 5, page 12

Lines 15-20 of the first reference discuss the limitations of the Stevensville area distribution system and state that CNPI plans to upgrade the system to provide more "contingency and operating flexibility". The second reference discusses these plans which appear to be the installation of a third ratio bank. Please explain what other options were considered and why another ratio bank was selected as the preferred option for the Stevensville area.

RESPONSE:

Other options considered:

1. Construct a 4.16 kV substation to replace the existing ratio banks. The estimated cost is $2 million.
2. Convert the Stevensville area from 4.16 kV to 34.5 kV. The total cost of the conversion is over $3 million.

The cost of installing the 3rd ratio bank and the upgrade the distribution line for contingency and operating flexibility purpose in the Stevensville area is $400,000. This option was selected because it meets the objective of providing contingency and operating flexibility at the least cost.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

8. Ref: Exhibit 2, Tab 2, Schedule 5, page 3

Lines 10 – 15 discuss a 2009 project to relocate back lot overhead to front lot underground in the Point Abino subdivision. Reference is made to a contribution in aid of construction (CIAC) of $178,000.

a) How was the amount of contribution arrived at?

b) What is CNPI's policy for CIAC when lines are rebuilt/relocated?

c) Is the ROW mentioned in line 14 a public right of way or is the Point Abino subdivision private (i.e. Is this a condominium subdivision?)

d) If the answer to 3 is that Point Abino is a condominium subdivision, would CNPI's policy for CIAC differ for lines being relocated to public road allowance?

RESPONSE:

a) The amount of CIAC was determined based upon CNPI's policy for relocating plant. The methodology is summarised as follows:

- Estimate the total cost of the line relocation requested by the customer (A).
- Estimate the future cost of rebuilding the line in accordance with CNPI's long-range rebuilding plan. Calculate the present value of this cost (B).
- Calculate CIAC by subtracting (B) from (A).

[NTD: But did your estimate of future cost of rebuilding assume front lot underground? Energy Probe wants to argue that undergrounding is more expensive than like-for-like, so the CIAC should have been higher. For this response, I wouldn't get into your general policy. I would say exactly how you calculated the $178,000 CIAC.]

b) A CIAC is not required if the project is initiated by CNPI. If the relocation project requested by a customer is in the current budget, the customer will pay the incremental cost of their specific request (e.g., underground or different route).

c) The Point Abino subdivision is privately owned. However, CNPI owns the distribution system in the subdivision and has easements for land occupation.

d) No.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

9. Ref: Exhibit 2, Tab 2, Schedule 5, page 4

Lines 5-9 of the exhibit discuss the 2011 Niagara Parkway rear lot rebuild.

a) Was the line rebuilt as overhead?

b) If so, was it relocated to CNPI owned right of way or to the public road allowance of Niagara Parkway?

c) Was a CIAC involved? If so, please provide details.

RESPONSE:

a) Yes.

b) It was relocated to CNPI owned right-of-way.

c) No.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

10. Ref: Exhibit 2, Tab 2, Schedule 5, page 5

Line 25 references "aerial cable" and its replacement with "open conductor".

a) Please explain the differences between these two types of conductor.

b) Why was the aerial cable not just replaced with new aerial cable?

c) Please explain the need for "*multiple* open conductor circuits" if the project need was just to replace deteriorated plant.

RESPONSE:

a) Aerial cables are fully insulated and bundled cables installed on the poles. Open conductors are standard bare conductors, such as 3/O ACSR.

b) The aerial cables are not in current construction standards and are more expensive.

c) The existing pole line had multiple circuits (aerial cables) and was replaced with multiple circuits (open conductors).

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

11. Ref: Exhibit 2, Tab 2, Schedule 5, page 7

Lines 23-24 describe two new underground services in 2011 to a pumping station and an historic park.

a) Did this project involve a CIAC?

b) If yes, please provide details.

c) If no, please explain CNPI's policy for CIACs when underground rather than overhead services are provided.

RESPONSE:

a) Yes.

b) The CIAC from the pumping station and the historical park was $15,625 and $22,124, respectively.

c) N/A.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

12. Ref: Exhibit 2, Tab 2, Schedule 5, page 10

Lines 7-16 describe the Ridge Road North Beautification project and notes that the Town of Fort Erie provided a CIAC to cover the entire cost of the project. Line 16, though, notes that $97,000 was allocated to the Voltage Conversion classification.

a) Was the $97,000 included in the CIAC or was this part of the project funded by CNPI?

b) If the $97,000 was funded by CNPI please explain the policy for apportioning costs between the town and the utility.

c) If the $97,000 was funded by the CIAC please explain the significance of allocating it to the voltage conversion classification (i.e. Since CIACs are not included in rate base, why is it necessary to allocate the cost anywhere?)

RESPONSE:

a) The $97,000 was funded by CNPI.

b) The beautification project required CNPI to bury all aerial crossings on Ridge Road North. The Town of Fort Erie contributed the full cost of this project. In keeping with its long-range voltage conversion program, CNPI spent $97,000 to convert 4.8 kV delta circuits in the affected area to 8.3 kV wye. This allowed CNPI to gain the efficiencies of undertaking a single project to meet the objectives of beautification and voltage conversion.

c) N/A.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

13. Ref: Exhibit 2, Tab 2, Schedule 5, page 11

This page of the exhibit describes the Garrison Road streetscaping project in 2008-2009 and notes that a CIAC of $232,000 was received from the Town of Fort Erie. The table at line 9 shows 2009 expenditure of $522,000.

a) Please elaborate on how the amount of CIAC was arrived at.

b) What parts of the project were covered by the CIAC and what parts were financed by CNPI?

c) Are the underground "electrical service wires" referred to in lines 14-15 secondary conductors or was the primary also buried?

RESPONSE:

a) Because this project entailed a road widening, the CIAC was derived based on the Public Service Works on Highway Act, in accordance with the OEB Distribution System Code, section 3.4.

b) Under the provisions of the Act noted in a) above, CNPI covered 100% of the material costs and 50% of the costs of labour and labour-saving devices associated with the relocation of overhead plant. The Town of Fort Erie covered the other 50% of the cost of labour and labour saving devices. The Town also covered incremental costs related to beautification initiatives, such as concrete poles and underground construction.

c) Portions of both primary and secondary wire were buried.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

14. Ref: Exhibit 2, Tab 2, Schedule 5, page 16

Lines 13-19 refer to major underground projects to replace "aged, deteriorated underground plant".

a) Was this underground plant originally paid for by CIAC?

b) If yes, does CNPI require customers served by the new underground to provide a CIAC for the difference in cost between overhead and underground service?

c) Please comment on why new underground service is treated differently in terms of CIAC than replacement underground service.

RESPONSE:

a) CNPI does not know, as this underground plant was installed approximately 35 years ago. It is assumed that any CIAC was based on the regulatory rules applied at that time.

b) No, CNPI does not require customers served by the new underground to provide a CIAC for the difference in cost between overhead and underground service.

c) In accordance with Section 3 and Appendix B of the Distribution System Code, new load customers must be charged for their net connection costs (after Discount Cash Flow evaluation). Hence, new load customers, including those served underground, are charged a CIAC. However, once

CNPI assumes ownership of the newly installed assets, any future costs related to replacements, renewals, and retirement of said assets are borne by CNPI and become part of the rate base.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

15. Ref: Exhibit 2, Tab 2, Schedule 5, page 17

This page discusses the 2011 St. Georges Court rebuild and mentions a CIAC of $82,000 from the Town and a cable company.

a) Please break out the respective shares of the CIAC from the Town and the cable company.

b) What was the Town's contribution for?

c) What was the cable company's contribution for?

RESPONSE:

a) The Town of Fort Erie contributed $30,000. The cable company contributed $52,000.

b) The Town's contribution was for the underground infrastructure of the street light system owned by the Town.

c) The cable company's contribution was for the portion of the common underground trench that accommodated communication cables.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

16. Ref: Exhibit 2, Tab 2, Schedule 5, page 17

This page also discusses the 2012 Dodd's Court rebuild and mentions $93,000 CIAC from the Town of Fort Erie and a cable company.

a) Please break out the respective shares of the CIAC from the Town and the cable company.

b) What was the Town's contribution for?

c) What was the cable company's contribution for?

RESPONSE:

a) The Town of Fort Erie contributed $35,000. The cable company contributed $58,000.

b) The Town's contribution was for the underground infrastructure of the street light system owned by the Town.

c) The cable company's contribution was for the portion of the common underground trench that accommodated communication cables.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

17. Ref: Exhibit 2, Tab 2, Schedule 5, page 26

This part of the exhibit discusses the Distribution Analysis Tools Project. Please describe the benefits CNPI has derived or will derive from the project including any cost and labour savings compared to previous methods of performing the analysis work.

RESPONSE:

The Distribution Analysis Tools project will implement computerized engineering and operational tools to facilitate more effective and efficient system planning, outage management, project planning, mapping, and asset management. These tools will operate on an integrated basis using a comprehensive digital database of all significant system components, such as poles, conductors, transformers, switches, meters, and protective devices. These applications will provide efficiencies by automating processes that are currently done manually or by streamlining existing processes. The project will enhance engineering and operations functions by providing access to a wide range of system information, and by facilitating integration with other systems such as the Smart Meter network and SCADA systems that can provide valuable real-time system information. Descriptions of the functions that will be implemented and the associated benefits of each are as follows:

- Engineering Analysis, to perform system studies such as load flow, voltage drop, and protection co-ordination. This module will facilitate the preparation of short- and longer-term system planning studies. At present, the process for

undertaking these studies is mostly a manual process. The new system will provide a more powerful and flexible tool for performing system analyses, and will also allow for different scenarios to be analysed more easily. The module could also be employed in emergency situations to ensure that system components are not seriously overloaded when backup supplies are activated. The new system will also facilitate analyses of new generation connections and arc-flash studies, addressing modern-day realities on the power grid.

- Field Staking, for preparing project plans. This module will be utilised by Planning personnel to prepare project plans. Because the system is an integrated one, the planning process will be made more efficient because Planners will have access to a comprehensive database of system assets residing in one location, rather than having to access various databases for information. The flow of information from Planning to operational personnel will also be streamlined. When projects are complete, drawings can be easily uploaded to update the centralised database to reflect system changes. At present, the process of updating system maps and information is an entirely manual process.

- Outage Management System (OMS), to streamline aspects of the outage management process and provide more comprehensive information on outages. This will lead to enhanced outage response, more effective communication with customers, and automate record-keeping functions. The OMS will display in a GIS environment a visual representation of sections of lines and customers that are without power. The outage management system will allow for earlier assessments to be made of how widespread an outage is and what response is required, leading to operational efficiencies. The system will facilitate more effective communication between operational and customer service personnel on restoration efforts, which in turn allows for more effective communication with customers. By operating off the integrated

database and interfacing with the Customer Information System, the OMS will accurately track how many customers, and which specific customers, are without power at any one time. This will facilitate more effective tracking of outage data and will allow for more detailed analyses of underperforming sectors of the distribution system. The OMS will also automate the process of tracking outage statistics, which in the present environment is an entirely manual process. The effectiveness of the OMS will be even more enhanced when Smart Meter outage information is integrated into the system. This will allow CNPI to be aware of outages even before customers call in to report, further improving CNPI's outage response.

- GIS (Geospatial Information System) and Mapping, to provide a comprehensive geospatial model of the CNPI system to support the above applications and also to facilitate asset management initiatives. The GIS will form a comprehensive, integrated repository of system assets that can be displayed in a geographical environment, replacing a variety of databases that presently exist at CNPI. At present, the updating of system maps is mostly a manual process, where AutoCAD-based maps are updated manually when projects are complete. As described earlier, the new system will automate the process of mapping updates, and will also facilitate a move towards more computer-based maps rather than relying solely on "paper" maps. The system also will make it easier for operational staff to have access to recent system changes, as such changes can be easily made in the system.

This project, therefore, will realise significant gains in efficiency due to improvements to overall system analysis, project planning and design, and construction workflow. The OMS will provide better outage response and restoration times, improved outage triage and repair prioritization during major events (such as storms), and improved customer satisfaction via improved

information exchange. The use of these new tools will allow for these enhanced tasks without expanding staff complement and incurring consequent increased operational costs.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

18. Ref: Exhibit 2, Tab 2, Schedule 5, page 29

This part of the exhibit discusses transport equipment.

a) Please provide a listing of transport and work vehicles in the CNPI fleet.

b) Please describe the policy for replacing vehicles.

c) How are surplus vehicles disposed of?

d) What facilities and staff does CNPI have to service and maintain its fleet?

RESPONSE:

a) Please refer to Board Staff interrogatory #9 a).

b) Please refer to Board Staff interrogatory #9 c).

c) Surplus vehicles are disposed of in one of three ways:

i) Vehicles are traded into the manufacturer of the replacement unit.

ii) Vehicles are liquidated with an auction company.

iii) An assessment is carried out by a third party full mechanical vehicle maintenance company to establish a residual value. The unit is then placed up for sale.

d) CNPI has a Service Centre in Fort Erie and Gananoque to secure fleet vehicles and all heavy vehicles are parked inside truck bays. All ongoing fleet mechanical maintenance and servicing are carried out by third party full mechanical and tire service providers. CNPI management plans maintenance schedules, maintains service records and licensing, monitors all operating costs, and develops replacement schedules. Also, CNPI engages the services of PHH, an international commercial vehicle fleet management company to provide fuel expense, fleet maintenance and vehicle expense management. CNPI staff will pick up and deliver vehicles to third party services providers when required.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

19. Ref: Exhibit 2, Tab 2, Schedule 5, pages 38 – 39

Lines 20-24 on page 38 describe the backlot line upgrade project.

a) Will the replacement be overhead or underground? If the former, please explain CNPI's policy for replacing overhead plant with underground.

b) Please explain why the existing plant cannot be rebuilt in the same location.

c) What would the cost savings be of rebuilding the line in its existing location over moving it to road allowance?

d) How much more backlot relocation work is planned over and above the 30 poles mentioned in this section?

RESPONSE:

a) The existing overhead lines will be replaced with overhead lines.

b) The existing plant can be rebuilt in the same location. However, rebuilding overhead primary lines in the backlot will have the following disadvantages:

- The backlot lines will increase restoration time following outages due to limited access and will reduce system reliability.

- Some of the backlot lines which are actually in alley ways are in close proximity to buildings and other structures. Rebuilding in the same place will increase costs to meet current construction standards and may impact upon public safety.

- Backlot construction generally has higher construction costs and higher maintenance costs (e.g., tree trimming) due to limited accessibility.

c) CNPI is evaluating both options and will select the lower cost option.

d) Gananoque system has significant amount of backlot construction. CNPI will continuously evaluate the option of rebuilding plant in the same location or relocating to a more readily accessible location.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

20. Ref: Exhibit 2, Tab 2, Schedule 5, page 41

Lines 7-8 on this page of the exhibit describe the 2012 replacement of a deteriorated bucket truck with a material handler.

a) How old is the deteriorated bucket truck?

b) What is the difference between the old unit and the new "material handler" unit?

c) What is the old unit lacking that makes it unsuitable for work on the 26.4 kV system?

d) Will the new material handler unit be equipped to work on the 26.4 kV system? If no, please explain why it is not necessary for the unit to work on this voltage level.

RESPONSE:

a) The deteriorated bucket truck is a 1994 model.

b) The new truck has additional reach to access the 26.4 kV top circuits, it has a jib, which is used to transfer conductors, and it is equipped with boom mounted electrical test points.

c) The boom must be subjected to a metered current leakage test prior to working on phase to phase circuits above 15 kV according to rule 123 of the E&USA rule book. The old truck does not have sufficient reach, does not have a jib or functioning electrical test points.

d) Yes, see b) above.

(EP)

2. Rate Base

2.1 Is the proposed CNPI – Fort Erie/Gananoque rate base for the test year appropriate?

21. Ref: Exhibit 2, Tab 3, Schedule 1, Distribution Asset Management Plan

Page 14 contains a note that not all ratio bank installations are metered "so peak loading can only be approximated".

a) Please describe how CNPI approximates the peak loading on a ratio bank.

b) Why does CNPI not meter each installation?

c) What are the risks of not knowing the actual peak loading on each ratio bank?

RESPONSE:

a) Historically, during analysis related to system planning, estimated peak loads are allocated to each connected transformer on the circuits under evaluation to perform load-flow calculations, which is then adjusted to match real-world observed data, such as substation breaker currents and momentary current measurements down line on the circuit(s). The resulting close approximations of these load flows (currents) are applied to each element in the study model, including any ratio banks in the area under study. With the introduction of more detailed hourly load information available from CNPI's Smart Meters and ongoing implementation of new Engineering Analysis (EA) software tools, this process is expected to become even more accurate and labor-efficient in the future.

b) CNPI has made no specific investments to allow for metering the loads on any of its ratio bank installations. The costs of installing such primary metering facilities were deemed to be excessive compared to the value of the ratio bank equipment itself. Rather, CNPI is able to directly meter critical large three-phase ratio bank loads using circuit protective equipment in proximity to the ratio banks.

c) There is minimal risk in not directly measuring the peak loads on small single-phase ratio transformers on an ongoing basis. CNPI does calculate the peak loading on these ratio transformers during regular evaluation of loading on major system components as part of its ongoing system planning process. In addition, instantaneous load readings are collected from time-to-time using handheld measuring equipment.

(VECC)

2. Rate Base

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

36. Reference: Exhibit 2, Tab 2, Schedule 1

a) Was CNPI's Distribution Asset Management Program (DAMP) reviewed by an outside party?

b) What measurable objectives have been instituted as part of the DAMP process in order to assess whether the plan has a positive impact on distribution service?

c) How are these objectives reflected in employee compensation/incentives?

RESPONSE:

a) No.

b) The measurable objectives will be System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI reflects the total outage time to the average customer over a period of one-year. SAIFI reflects the number of interruptions to the average customer over a one-year period.

c) These objectives are included as corporate targets under CNPI's short-term incentive plan referred to in Exhibit 4, Tab 4, Schedule 1. The specific SAIDI and SAIFI targets for 2012 are files in response to SEC IR #14.

(VECC)

2. Rate Base

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

37. Reference: Exhibit 2, Tab 2, Schedule 4, pages 1-7; Exhibit 2, Tab 2, Schedule 10, pages 1-7 Board Staff IR #8

a) Please restate the Capital Project Tables by separating out Fort Erie from EOP for the 2007-2013.

RESPONSE:

In CNPI's 2009 cost of service application (EB-2008-0222 and EB-2008-0223), the Company received approval to harmonize Fort Erie and Gananoque. One of the rationales to harmonize was to eliminate the duplication of regulatory reporting. Reporting schedules for both Fort Erie and Gananoque would contradict the rationale of the harmonization.

While not necessary to separate, the details and tables of 2007-2013 capital projects for Fort Erie and Gananoque are included on pages 1-32 and pages 33-42, respectively, of Exhibit 2 Tab 2 Schedule 5 of the pre-filed evidence.

2. Rate Base

2.2
Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

(EP)

2. Rate Base

2.2 Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

22. Ref: Exhibit 2, Tab 1, Schedule 7, page 5

a) Please provide a version of the continuity schedule for 2013 that has smart meters (and related assets) included in the opening 2013 balance and has stranded meters removed from the opening 2013 balance. Please also ensure that the appropriate adjustments are made to the opening balances for accumulated depreciation.

b) Please show the calculation of the smart meter related accumulated depreciation expenses shown in the table.

RESPONSE:

a) Please refer to page 3 below.

b) The CNPI – PC Smart Meter accumulated depreciation values were taken from Exhibit 10 of the rate application. Please refer to Table 2.2.1 below for tie-out. For the actual calculations, please refer back to the Exhibit 10 referenced cells noted in Table 2.2.1 below.

Table 2.2.1: CNPI – PC Smart Meter Accumulated Depreciation Tie-out

OEB Acct #	Account Description	Per Exhibit 2 PC	Per Exhibit 10 PC		Difference
1860	D Meters	(322,516)	(322,516)	**A**	-
1865	D Other Install on Cust Prem	(4,767)	(4,767)	**B**	-
1920	GA Comp Hardware	(1,564)	(1,564)	**C**	-
1925	GA Comp Software	(23,071)	(23,071)	**D**	-
	Total	**(351,917)**	**(351,917)**		**-**

Notes:

A Cell S31 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S6

B Cell S107 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S6

C Cell S50 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S6

D Cell S69 of '4. SM_Assets_and_Rate_Base' tab within E10_T1_S6

CANADIAN NIAGARA POWER INC.
FIXED ASSETS CONTINUITY SCHEDULE
December 31, 2013

CO. #0020 PC Distribution

		COST					ACCUMULATED DEPRECIATION						NBV
OEB ACCT #	ACCOUNT DESCRIPTION	COST BEGINNING OF THE YEAR	ADDITIONS	COST END OF PERIOD	ALLOCATIONS	ADJUSTED COST END OF PERIOD	ACC DEP'N BEGINNING OF THE YEAR	ADDITIONS	DEPRECIATION ON AQUIRED ASSETS	ACC DEP'N END OF PERIOD	ALLOCATIONS	ADJUSTED ACC DEP'N END OF PERIOD	
1608	Franchises & Consents	-	-	-		-	-	-	-	-		-	-
1805	D Land	21,867	-	21,867		21,867	-	-	-	-		-	21,867
1806	D Land Rights	98,965	50,000	148,965		148,965	(8,513)	(2,476)	(1,265)	(12,253)		(12,253)	136,712
1808	D Bldgs & Fixtures	340,114	-	340,114		340,114	(54,688)	(4,833)	(13,683)	(73,204)		(73,204)	266,910
1820	D Station Equipment < 50KV	5,803,185	453,657	6,256,842		6,256,842	(807,047)	(180,900)	-	(987,948)		(987,948)	5,268,894
1830	D Poles,Towers&Fixtures	4,008,255	425,532	4,433,786		4,433,786	(760,117)	(128,377)	(169,286)	(1,057,780)		(1,057,780)	3,376,006
1835	D OH Cond & Devices	3,950,572	285,283	4,235,855		4,235,855	(649,944)	(104,973)	(99,422)	(854,338)		(854,338)	3,381,517
1840	D UG Conduit & Manholes	443,599	126,254	569,854		569,854	(46,223)	(6,580)	(44,973)	(97,776)		(97,776)	472,078
1845	D UG Cond & Devices	1,149,936	98,524	1,248,459		1,248,459	(171,610)	(34,884)	(9,211)	(215,705)		(215,705)	1,032,755
1850	D Line Transformers	2,801,492	145,758	2,947,250		2,947,250	(464,878)	(65,390)	(117,144)	(647,412)		(647,412)	2,299,838
1855	D Services	1,550,078	321,383	1,871,461		1,871,461	(169,926)	(50,898)	(2,391)	(223,215)		(223,215)	1,648,246
1860	D Meters	1,870,814	90,573	1,961,387		1,961,387	(366,676)	(140,734)	(7,239)	(514,648)		(514,648)	1,446,739
1865	D Other Install on Cust Prem	84,473	-	84,473		84,473	(19,234)	(9,098)	-	(28,332)		(28,332)	56,141
1875	D St Lites & Signal Systems	-	-	-		-	-	-	-	-		-	-
1908	GA Bldgs & Fixtures	140,288	-	140,288		140,288	(23,461)	(2,806)	-	(26,267)		(26,267)	114,021
1915	GA Office Furn & Equipment	22,668	-	22,668	337,931	360,599	(8,942)	(1,886)	-	(10,828)	(324,478)	(335,306)	25,293
1920	GA Comp Hardware	98,473	-	98,473	390,992	489,464	(77,252)	(7,575)	-	(84,827)	(285,924)	(370,752)	118,713
1925	GA Comp Software	321,024	-	321,024	939,341	1,260,364	(130,556)	(33,957)	-	(164,513)	(574,109)	(738,622)	521,742
1930	GA Transportation Equipment	-	-	-	821,676	821,676	-	-	-	-	(496,145)	(496,145)	325,531
1935	GA Stores Equip	486	-	486	43,200	43,686	(486)	-	-	(486)	(41,286)	(41,772)	1,914
1940	GA tools,shop&garage equip	14,089	-	14,089	184,731	198,820	(13,117)	(648)	-	(13,765)	(166,716)	(180,481)	18,339
1945	GA measure&test equip	-	-	-	126,584	126,584	-	-	-	-	(110,350)	(110,350)	16,234
1950	GA power op equip	-	-	-	-	-	-	-	-	-	-	-	-
1955	GA Comm Equipment	115,114	-	115,114	240,130	355,243	(104,848)	(1,588)	-	(106,435)	(109,721)	(216,156)	139,087
1960	GA Misc. Equip	-	-	-	146,405	146,405	-	-	-	-	(50,719)	(50,719)	95,686
1980	GA System Supv Equip	69,804	46,590	116,394	221,812	338,206	(20,281)	(9,310)	-	(29,591)	(181,020)	(210,611)	127,595
1995	Contributions & Grants	(2,022,942)	(140,000)	(2,162,942)		(2,162,942)	192,039	62,199	-	254,237		254,237	(1,908,705)
	Total before AUC	20,882,352	1,903,554	22,785,907	3,452,801	26,238,707	(3,705,759)	(724,713)	(464,613)	(4,895,085)	(2,340,467)	(7,235,553)	19,003,155
2055	Asset Under Construction	348,754	37,180	385,934		385,934	-	-	-	-		-	385,934
	Total after AUC	21,231,106	1,940,735	23,171,840	3,452,801	26,624,641	(3,705,759)	(724,713)	(464,613)	(4,895,085)	(2,340,467)	(7,235,553)	19,389,088

(EP)

2. Rate Base

2.2 Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

23. Ref: Exhibit 2, Tab 2, Schedule 11, page 13

This part of the exhibit describes the replacement of switchgear and relaying equipment at Barrick DS.

a) Is the forecasted expenditure in 2012-2013 the entire cost of the project or are additional expenditures planned after 2013 for switchgear and relay changes? If the latter, please provide the total estimated cost of the project.

b) When does CNPI expect the balance of the station will require rebuilding?

c) Will the station be rebuilt in its existing location or will it be replaced by another station at a different location?

d) When the station is rebuilt either in its present location or at a new one, how much of the switchgear and relaying being done now will be suitable for reuse?

RESPONSE:

a) The forecast expenditures for 2012 and 2013 represent the entire estimated cost of the project.

b) The balance of the station consists primarily of the power transformer, the building, and civil structures. CNPI anticipates that the power transformer will need to be replaced in approximately five years. At that time, substation upgrades such as the installation of oil containment systems and blast walls will also be implemented.

c) The station will be rebuilt in its existing location.

d) CNPI anticipates that the new switchgear and relaying will have a useful life of approximately 40 years. Therefore, when the substation is rebuilt, the switchgear/relaying will remain in use.

(EP)

2. Rate Base

2.2 Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

24. Ref: Exhibit 2, Tab 2, Schedule 11, page 15

This page of the exhibit describes the 43M11 refurbishment project.

a) How old is the line?

b) What components are in deteriorating condition as mentioned at line 25?

c) How much extra will it cost to relocate the off road sections as opposed to rebuilding them in the existing location?

RESPONSE:

a) This line is over 40 years old.

b) The poles are deteriorated.

c) There will be no increased cost. In fact, relocating the off road section to the road allowance will reduce the cost of construction due to the accessibility issues associated with off road construction requiring special equipment.

(EP)

2. Rate Base

2.2 Is the proposed CNPI – Port Colborne rate base for the test year appropriate?

25. Ref: Exhibit 2, Tab 2, Schedule 11, pages 15-16

These pages describe the PCB mitigation project showing expenditures of $200 k in 2012 and $150 k in 2013.

a) What is the estimated ultimate cost of this program at completion?

b) Please describe what activities are undertaken in the program.

c) How many bushings potentially have PCB levels greater than 500 pmm?

d) Does the budget include the cost of replacing some bushings or is it just for testing costs?

e) If the latter, please explain why this program is so expensive when only a few bushings at Barrick DS and Sherkston DS will be tested according to lines 14-16 on page 16.

RESPONSE:

a) The estimated cost of this program is $500k.

b) The activities undertaken in the program are: 1) Surveying bushings on the system to identify those that may be PCB contaminated, based on the age, make, and style of the bushing; 2) Testing (where practical) suspect bushings to determine their PCB content; 3) Replacing with PCB-free components any bushings that exceed the regulatory threshold for PCB content; and 4) Proper disposal of any PCB contaminated equipment. Factors such as the age and condition of the transformer would also be considered. In cases where the transformer is in deteriorating condition or is

near the end of its useful life, CNPI-PC may choose to replace the transformer. There are also cases where bushings are of a sealed-construction type and the oil they contain cannot be sampled. In these cases, testing would not be conducted, but either the suspect bushing or transformer would be replaced.

c) Eighteen bushings potentially have PCB levels greater than 500 ppm.

d) Yes, the budget includes the cost of replacing some bushings.

e) See d) above.

(VECC)

2. Rate Base

2.2 Is the CNPI proposed Working Capital Allowance appropriate?

38. Reference: Exhibit 2, Tab 2, Schedule 10, page 1

a) Did CNPI complete a lead/lag study or undertake any comparison to the 13% value for working capital. If so please provide this analysis.

RESPONSE:

a) CNPI did not complete a lead/lag study or undertake any comparison to the 13% value for working capital.

2. Rate Base

2.3
Is the CNPI – Fort Erie/Gananoque working capital allowance for the test year appropriate?

(EP)

2. Rate Base

2.3 Is the CNPI – Fort Erie/Gananoque working capital allowance for the test year appropriate?

26. Ref: Exhibit 2, Tab 1, Schedule 9

Please provide the split between RPP and non-RPP volumes by rate class based on actual 2011 data.

RESPONSE:

Please refer to Table 2.3.1 below for CNPI – FE/EOP split between RPP and non-RPP volumes by rate class based on 2011 actual data.

Table 2.3.1 CNPI – FE/EOP Split Between RPP and Non-RPP kWhs

Rate Class	RPP	Non-RPP	Total kWh's
Residential	125,814,207	16,951,912	142,766,119
General Service <50 kW	43,163,872	4,129,875	47,293,747
General Service >50 kW	12,330,211	130,052,810	142,383,021
Street Lighting	114,708	2,573,111	2,687,819
Sentinel Lighting	700,096	47,609	747,705
Scattered Unmetered Load	946,100	14	946,114
Total	**183,069,194**	**153,755,331**	**336,824,525**

(EP)

2. Rate Base

2.3 Is the CNPI – Fort Erie/Gananoque working capital allowance for the test year appropriate?

27. Ref: Exhibit 2, Tab 1, Schedule 13, page 3

a) Please update the cost of power to reflect the most recent Navigant Report Regulated Price Plan and to reflect the split between RPP and non-RPP volumes based on applying the response to the previous interrogatory to the 2013 volume forecast. Please specify the rate used for the RPP and non-RPP volumes.

b) Please specify the loss factor used in the calculation of the cost of energy.

RESPONSE:

a) The Regulated Price Plan Report, May 1, 2012 to April 30, 2013, dated April 2, 2012, at Table 2 on page 22, Average RPP Supply Cost Summary, specifies the following:

Forecast Wholesale Electricity Price	$21.05 per MWh
Impact of Global Adjustment	$57.72 per MWh
Average Supply Cost for Non-RPP Consumers	$78.77 per MWh
Average Supply Cost for RPP Consumers	$80.69 per MWh

The updated cost of power arising from the updated Navigant Report Regulated Price Plan is shown in the following table. The percentage of sales for RPP and Non-RPP consumers is based on the response to the previous interrogatory #26. In the Application at Exhibit 2 Tab 1 Schedule 13 Page 3, this amount was described as “Cost of Energy” and was forecasted at $26,322,125. It will be necessary to update the evidence to reflect the

updated Regulated Price Plan Report, May 1, 2012 to April 30, 2013, dated April 2, 2012.

Fort Erie								
	2013 Forecast kWh	% RPP	%Non-RPP	RPP Price	Non-RPP Price	Loss Factor	RPP Cost of Power	Non-RPP Cost of Power
Residential	114,771,086	88%	12%	0.08069	0.07877	1.0391	8,468,222	1,127,280
GS Less Than 50 kW	36,317,617	91%	9%	0.08069	0.07877	1.0391	2,770,995	267,533
GS 50 to 4,999 kW	119,171,016	9%	91%	0.08069	0.07877	1.0391	899,270	8,876,264
USL	788,656	4%	96%	0.08069	0.07877	1.0391	2,645	61,969
Sentinel Lighting	687,244	99%	1%	0.08069	0.07877	1.0391	57,046	563
Street Lighting	2,136,308	100%	0%	0.08069	0.07877	1.0391	179,119	-
							12,377,297	10,333,610
Gananoque							Subtotal	22,710,907
	2013 Forecast kWh	% RPP	%Non-RPP	RPP Price	Non-RPP Price	Loss Factor	RPP Cost of Power	Non-RPP Cost of Power
Residential	29,354,957	88%	12%	0.08069	0.07877	1.0715	2,233,449	297,314
GS Less Than 50 kW	12,578,164	91%	9%	0.08069	0.07877	1.0715	989,625	95,546
GS 50 to 4,999 kW	16,434,932	9%	91%	0.08069	0.07877	1.0715	127,886	1,262,299
USL	157,458	4%	96%	0.08069	0.07877	1.0715	545	12,758
Sentinel Lighting	60,462	99%	1%	0.08069	0.07877	1.0715	5,175	51
Street Lighting	551,513	100%	0%	0.08069	0.07877	1.0715	47,683	-
							3,404,363	1,667,969
							Subtotal	5,072,331
						Cost of Power		**$ 27,783,238**

b) The loss factors used in the determination are the most recent Board approved loss factors for Fort Erie and Gananoque and are specified in the table provided in part a.

2. Rate Base

2.4
Is the CNPI – Port Colborne working capital allowance for the test year appropriate?

(EP)

2. Rate Base

2.4 Is the CNPI – Port Colborne working capital allowance for the test year appropriate?

28. Ref: Exhibit 2, Tab 1, Schedule 9

Please provide the split between RPP and non-RPP volumes by rate class based on actual 2011 data.

RESPONSE:

Please refer to Table 2.4.1 below for CNPI – PC split between RPP and non-RPP volumes by rate class based on 2011 actual data.

Table 2.4.1 CNPI – PC Split Between RPP and Non-RPP kWhs

Rate Class	RPP	Non-RPP	Total kWh's
Residential	56,508,499	7,508,303	64,016,802
General Service <50 kW	20,254,749	3,929,790	24,184,539
General Service >50 kW	7,459,582	105,533,579	112,993,161
Street Lighting	27,474	1,760,108	1,787,582
Sentinel Lighting	13,333	0	13,333
Scattered Unmetered Load	581,617	198	581,815
Total	**84,845,253**	**118,731,979**	**203,577,232**

(EP)

2. Rate Base

2.4 Is the CNPI – Port Colborne working capital allowance for the test year appropriate?

29. Ref: Exhibit 2, Tab 1, Schedule 13, page 4

a) Please update the cost of power to reflect the most recent Navigant Report Regulated Price Plan and to reflect the split between RPP and non-RPP volumes based on applying the response to the previous interrogatory to the 2013 volume forecast. Please specify the rate used for the RPP and non-RPP volumes.

b) Please specify the loss factor used in the calculation of the cost of energy.

RESPONSE:

a) The Regulated Price Plan Report, May 1, 2012 to April 30, 2013, dated April 2, 2012, at Table 2 on page 22, Average RPP Supply Cost Summary, specifies the following:

Forecast Wholesale Electricity Price	$21.05 per MWh
Impact of Global Adjustment	$57.72 per MWh
Average Supply Cost for Non-RPP Consumers	$78.77 per MWh
Average Supply Cost for RPP Consumers	$80.69 per MWh

The updated cost of power arising from the updated Navigant Report Regulated Price Plan is shown in the following table. The percentage of sales for RPP and Non-RPP consumers is based on the response to the previous interrogatory #28. In the Application at Exhibit 2 Tab 1 Schedule 13 Page 4, this amount was described as “Cost of Energy” and was forecasted at $14,036,403. It will be necessary to update the evidence to reflect the

updated Regulated Price Plan Report, May 1, 2012 to April 30, 2013, dated April 2, 2012.

Port Colborne								
	2013 Forecast kWh	% RPP	%Non-RPP	RPP Price	Non-RPP Price	Loss Factor	RPP Cost of Power	Non-RPP Cost of Power
Residential	64,161,933	88%	12%	0.08069	0.07877	1.0382	4,729,997	629,652
GS Less Than 50 kW	23,558,821	91%	9%	0.08069	0.07877	1.0382	1,795,956	173,396
GS 50 to 4,999 kW	88,694,743	6%	94%	0.08069	0.07877	1.0382	445,810	6,818,167
USL	581,815	1%	99%	0.08069	0.07877	1.0382	487	47,104
Sentinel Lighting	13,331	100%	0%	0.08069	0.07877	1.0382	1,117	-
Street Lighting	1,787,582	100%	0%	0.08069	0.07877	1.0382	149,750	-
							7,123,117	7,668,318
							Cost of Power	**$ 14,791,435**

b) The loss factors used in the determination are the most recent Board approved loss factor for Port Colborne and are specified in the table provided in part a.

2. Rate Base

2.5
Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

(OEB)

Rate Base

Issue 2.5
Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

8. Ref: E2/T4/S2 – Capital Expenditure Summary

a) Please provide an overall summary of capital expenditures over the past three historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress ("CWIP") as per *the* Filing Requirements issued June 28, 2012.
b) Please provide a table showing up-to-date spending on a proposed capital projects for the 2012 bridge year.
c) Please provide the expected in-service dates for those projects.

RESPONSE:

a) Please see table on page 2.

Appendix 2-A Summary
Capital Projects Table - FE and EOP

Projects	2007	2008	2009	2010	2011	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**ASPE**	**ASPE**	**MIFRS**
Delta to Wye Conversion	238,407	86,274	588,527	114,416	115,446	274,787	281,726
New transformers	207,445	277,327	213,854	171,618	268,323	262,435	276,580
Distribution Upgrades	1,086,131	1,298,700	1,461,123	893,844	1,041,369	1,400,397	1,365,875
Transportation Equipment	464,848	557,115	257,541	63,841	93,173	650,000	390,000
Dist Rebuilds Storms	66,977	162,747	115,877	0	0	0	50,513
Dist Analysis Tools	0	0	107,879	191,272	169,915	185,296	182,671
Substation	1,820,563	0	0	0	0	67,237	64,804
New meters	155,894	0	0	0	0	81,420	95,554
Install Reclos. Ratio transformer	184,135	0	0	0	0	100,202	170,683
New Service Lines	1,039,260	575,508	1,167,616	69,382	0	0	0
Service Centre	233,948	0	0	0	0	0	0
Land Purchases	188,431	0	0	0	0	0	0
IT projects	198,960	252,269	456,348	1,600,015	493,273	764,312	563,376
Queen St. Underground	0	66,203	0	0	0	0	0
Station 13	0	231,641	0	0	0	0	0
Upgrade VHF Radio System	0	165,508	0	0	0	0	0
Phone System	0	110,630	0	0	0	250,000	0
Sub Transmission Line	0	0	128,157	214,655	51,440	0	0
Overhead Services	0	0	320,396	154,516	436,162	203,801	239,149
Garrison Rd. Upgrade	0	0	521,971	0	0	0	0
Leasehold Improvements	0	0	54,805	0	289,975	0	0
Engineering Project	0	0	0	62,663	68,817	61,387	57,728
Underground Services	0	0	0	133,246	520,178	197,184	226,085
Station 12	0	0	0	0	147,309	130,103	184,749
St. George Crt. Rebuild	0	0	0	0	313,365	0	0
Dist. Station 19	0	0	0	0	0	179,949	0
Dodds Crt Rebuild	0	0	0	0	0	162,072	0
Stevensville Project	0	0	0	0	0	167,721	155,713
Environmental PCB	0	0	0	0	0	320,000	280,000
Upgrade Scada System	0	0	0	0	0	0	55,792
CIAC							
Distribution Upgrades	-80,036	-892,414	-506,954	-23,722	-169,045	-277,924	-225,000
New Service Lines	-251,093	-145,401	-122,691	-26,020			
Delta to Wye Conversion		-12,471			-5,532		
Sub Transmission Line				-36,876			
OH services				-19,582	-49,967	-20,000	-20,000
UG services				-70,062	-68,927	-40,000	-40,000
Dodds Crt Rebuild						-40,000	
Miscellaneous	-84,601	-255,285	-2,173	-438,111	-210,281		
Sub-Total	-415,730	-1,305,571	-631,818	-614,373	-503,752	-377,924	-285,000
GEC	876,564	738,862	717,900	399,058	730,377	732,660	0
AUC							
transfers to capital	-7,299,673	-4,937,603	-6,500,376	-4,541,392	-5,144,836	-6,651,946	-5,832,747
transfers in	5,599,656	6,844,631	5,222,846	5,189,448	5,385,937	6,788,557	5,962,391
Sub-Total	-1,700,017	1,907,028	-1,277,530	648,056	241,101	136,611	129,644
Miscellaneous	538,111	414,818	388,382	472,866	405,716	460,983	431,315
Total	**5,183,927**	**5,539,059**	**4,591,028**	**4,575,075**	**4,882,187**	**6,410,633**	**4,916,957**

Notes:

1 Please provide a breakdown of the major components of each capital project. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 Amounts should be reported on a MIFRS basis for the adoption year and any subsequent years, only.

The table below provides responses to b) and c).

Project (Fort Erie)	2012 Budget ($)	Spending to June 30, 2012 ($)	In-Service Date
Distribution Upgrades & Expansions	1,400,000	877,000	All projects will be complete by November 2012
OH Service Lines	204,000	99,000	Based on customer demand
UG Service Lines	197,000	70,000	Based on customer demand
Voltage Conversion	275,000	43,000	All projects complete by November 2012
Stevensville Reinforcement	168,000	153,000	2012 project complete
Purchase Transformers	262,000	75,000	Proposed purchases will be complete by November 2012
New Meters	81,000	57,000	December 2012
Recloser Installations	100,000	1,000	All projects complete by October 2012
Major Underground Projects	162,000	0	Dodds Court project complete by November 2012
Station Projects	377,000	77,000	Projects in progress; complete by December 2012
SCADA and communications	250,000	236,000	October 2012
Engineering Projects	61,000	13,000	All projects complete by November 2012
Distribution Analysis Tools	185,000	83,000	2012 project complete by December 2012
Transportation Equipment	650,000	214,000	Line trucks on order. Budget will be spent by Oct. 2012.
PCB Mitigation	320,000	30,000	In progress. 2012 works complete by December 2012
Total	**4,692,000**	**2,028,000**	

(OEB)

Rate Base

Issue 2.5
Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

9. Ref: E2/T2/S5, p. 29 - 31 – Transportation Equipment

a) Please provide an overview of CNPI's current fleet for Fort Erie as well as Gananoque.
b) Please provide a summary vehicle replacement schedule for three historic years, the bridge year and the test year, including Year, Make and total costs.
c) Please provide CNPI's vehicle replacement policy.
d) Please provide a forecast of CNPI's proposed vehicle replacement in 2014, 2015 and 2016.
e) Please provide an allocation of CNPI's fleet to service its Port Colborne service territory.

RESPONSE:

a) Overview of CNPI current fleet operating out of the **Fort Erie Service Centre:**

HEAVY VEHICLES				
COMPANY ID	**YEAR**	**VEHICLE TYPE, MODEL**	**TRUCK BRAND**	**DEPARTMENT**
92-6	1994	Digger/Derrick, Simon -Telelect	International	Line
8	1997	55 Foot Double Bucket Truck, Reach All	Freightliner	Line
2	1999	36 Foot Single Bucket Truck, Posi +	International	Line
7-18	2000	42 Foot Single Bucket Truck, Posi +	International	Line
7-19 (1)	2002	42 Foot Single Bucket Truck, Altec	Freightliner	Line
92-7	2007	Digger/Derrick, Terex	International	Line
7-21	2008	46 Foot Single Bucket Truck, Posi +	International	Line
7-22	2009	42 Foot Single Bucket Truck, Posi +	Freightliner	Line
SMALL TRUCKS, VANS, PASSENGER VEHICLES & TRAILERS				
1-33	2001	Malibu	Chevrolet	Customer Service
5-35	2002	E-150 Van	Ford	Planning
5-40	2003	C5500 Cube Van	GMC	Electrical
2-56	2004	¾ Ton Pickup	Ford	Line (U/G)
2-57	2004	2500 4x4 Pickup	Chevrolet	Facilities
5-39	2004	Astro Van	Chevrolet	Meter

5-41	2005	Astro Van	Chevrolet	Meter
2-59	2006	F-350 Dump 4x4	Ford	Line
5-43	2006	Grand Caravan	Dodge	Planning
5-44	2006	Grand Caravan	Dodge	Electrical
5-45	2007	E-150 Van	Ford	Electrical
2-60	2008	Ram 4x4 ½ ton Pickup	Dodge	Line
5-46	2008	Grand Caravan	Dodge	Pool Vehicle
5-47	2008	Montana	Pontiac	Meter
5-48	2008	Montana	Pontiac	Planning
5-49	2009	RAV 4 4x4	Toyota	Customer Service
2-61	2010	Ram 4x4 ½ Ton Pickup	Dodge	T&D Operations
5-50	2010	E-150 Van	Ford	Electrical
5-51	2010	Grand Caravan	Dodge	Pool Vehicle
5-52	2010	Grand Caravan	Dodge	Pool Vehicle
2-62	2011	F-150 4x4 ½ Ton Pickup	Ford	Line
5-53 (2)	2012	E-150 Van	Ford	Planning
TRAILERS				
T-6	1973	Dual Axle Reel Trailer	Ditc	Line
T-10	1979	Single Axle Reel Trailer	Mart	Line
T-11	1990	Single Axle Stone Trailer	York	Line
T-19	1995	Dual Axle Covered Trailer U/G	Haulmark	Line
T-20	1999	Dual Axle Utility Trailer	Home	Line
T-30 & T-31	2005	Tensioning Trailer (Brake Unit & Winching Unit	Timberland	Line
T-32	2010	Pole Trailer CZ 15 KP	CZ MFG	Line
T-33 (2)	2012	Tandem Axle Equipment Float D08	Hitchman	Line

(1) Unit to be retired in 2012 (2) Units purchased in 2012

Overview of CNPI current fleet operating out of the **Gananoque Service Centre**:

HEAVY TRUCKS				
COMPANY ID	**YEAR**	**VEHICLE TYPE, MODEL**	**TRUCK BRAND**	**DEPARTMENT**
7-20 (1)	1994	37 Foot Single Bucket, Altec	International	Line
EOP-16	2004	46 Foot Single Bucket, Altec	Freightliner	Line
EOP-18	2009	Digger/Derrick, Altec	International	Line
EOP-21 (2)	2012	46Foot Single Bucket, Posi +	International	Line

SMALL TRUCKS & TRAILERS				
EOP-8	1999	Pole Trailer	Kiefer	Line
EOP-17	2011	F150 4x4 Pickup	Ford	Line
EOP-20	2012	Jeep Patriot	Chrysler	Meter

(1) Unit to be sold **(2)** Delivery expected in 4th Quarter 2012

b) & d) Summary of historical vehicle replacements from 2009 and proposed vehicle replacements to 2016. The total cost presented is the total vehicle purchase price from the vendor. It does not include licensing, registration and other incidental costs required by provincial transportation legislation to enable highway use.

Fort Erie Service Centre

HEAVY VEHICLES					
COMPANY ID	YEAR REPLACED OR PLANNED TO BE REPLACED	VEHICLE TYPE, MODEL	TRUCK BRAND	DEPARTMENT	TOTAL COST
7-22	2009 (Historic)	42 Foot Single Bucket Truck, Posi +	Freightliner	Line	$212k
7-19	2012 (Bridge Year)	55 Foot (With 10 Foot Elevator Single/Double Bucket, Posi +	International	Line	$352k
92-6	2013 (Test Year)	Digger/Derrick, Specifications To Be Determined	To Be Determined	Line	$348k
7-18	2014 (Planned)	Single Bucket Truck, Specifications To Be Determined	To Be Determined	Line	$212k
2	2015 (Planned)	Single Bucket Truck, Specifications To Be Determined	To Be Determined	Line	$280k
8	2016 (Planned)	Double Bucket Truck, Specifications To Be Determined	To Be Determined	Line	$355k
SMALL TRUCKS, VANS & PASSENGER VEHICLES					
5-49	2009 (Historic)	RAV 4	Toyota	Customer Service	$26k
5-50	2010 (Historic)	E-150 Van	Ford	Electrical	$22k
2-61	2010 (Historic)	Ram 4x4, ½ Ton Pickup	Dodge	T&D Operations	$21k
T-32	2010 (Historic)	Pole Trailer, CZ 15 KP	CZ MFG	Line	$15k
2-62	2011 (Historic)	F-150 4x4, ½ Ton Pickup Quad Cab	Ford	Line	$27k
5-51	2011 (Historic)	Grand Caravan	Dodge	Pool Vehicle	$23k
5-52	2011 (Historic)	Grand Caravan	Dodge	Pool Vehicle	$23k
5-53	2012 (Bridge)	E-150 Van	Ford	Planning	$23k
2-56	2013 (Test)	¾ Ton Pickup	To Be Determined	Line (U/G)	$40k

5-39	2015 (Planned)	Van	To Be Determined	Meter	$23k
5-40	2015 (Planned)	Cube Van (Note: Truck Only, Cube to be Transferred)	To Be Determined	Electrical	$60k
5-43	2015 (Planned)	Van	To Be Determined	Planning	$23k
5-44	2015 (Planned)	Van	To Be Determined	Electrical	$23k
5-35	2016 (Planned)	Van	To Be Determined	Planning	$26k
5-41	2016 (Planned)	Van	To Be Determined	Meter	$26k

Gananoque Service Centre

HEAVY VEHICLES					
COMPANY ID	YEAR REPLACED OR PLANNED TO BE REPLACED	VEHICLE TYPE, MODEL	TRUCK BRAND	DEPARTMENT	TOTAL COST
EOP-21	2012	46 Foot Single Bucket Truck, Altec	International	Line	$283k
EOP-16	2016	46 Foot Single Bucket Truck,, Specifications to be Determined	To Be Determined	Line	$285k
SMALL TRUCKS & TRAILERS					
EOP-17	2011	F 150 4x4 Pickup, Quad Cab	Ford	Line	$29k
EOP-20	2012	Jeep Patriot	Chrysler	Meter	$24k

c) CNPI does not have a formal written vehicle replacement policy but does carry out planned vehicle replacements on a consistent schedule to ensure the fleet remains in optimal working condition, avoids higher maintenance costs and potential safety issues associated with operating deteriorated vehicles and power line maintenance equipment.

Factors considered in vehicle replacement include:

- vehicle age
- vehicle mileage
- vehicle condition, road worthiness (driver safety) and maintenance expenses
- vehicle material handling capacity

- vehicle reach

In circumstance where the specifications of the existing “in service” vehicle are deficient, investments will be made to ensure the replacement vehicle meets the needs. Two general parameters used for planning vehicle replacements are as follows:

- Line Vehicles (Heavy Trucks) - approximately 10 to 12 years
- Passenger Vehicles & Light Trucks - approximately 8 to 12 years or 190,000 kms

This schedule is consistent with industry practice and supports the optimization of vehicle life cycle cost.

e) The allocation to Port Colborne is 26% of the NBV of CNPI’s transportation equipment.

(OEB)

Rate Base

Issue 2.5
Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

10. Ref: E2/T3/S2, p.2 – Forecast Capital Expenditure

CNPI – FE/EOP provided a preliminary capital expenditure budget for the years 2013 through 2015.

a) Board staff noted that the forecasted capital budget for the 2013 includes General Expense Capital (GEC). The 2014 and 2015 forecast do not include any GEC. Please state if the 2013 capital forecast accounts for the proposed changes to CNPI's capitalization policy effective January 1, 2013.
b) If not, why not.
c) Please expand and re-file the table on E2/T3/S2/p.2 to include a forecast of the capital budget for the years 2016 and 2017 rate years.

RESPONSE:

a) As outlined in Exhibit 11, CNPI – FE/EOP is not seeking to recover General Expense Capital in its 2013 capital expenditures forecast. CNPI is proposing to change the overhead capitalization policy effective January 1, 2013.

b) N/A

c)

5-Year Capital Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
Canadian Niagara Power Inc.					
Distribution - Fort Erie					
Station 12 Projects (Conc & QEW)	185	75	50		
Station 15 Projects (Gilmore Rd)		15	225		
New Dist Station 20			1,600		
Voltage Conversion Program	282	300	300	600	600
Distribution Upgrades & Expansions	777	800	800	800	800
Overhead Service Lines	239	240	240	240	240
Underground Service Lines	226	230	230	230	230
Distribution Transformers	210	250	250	250	250
Transportation Equipment	390	225	300	375	400
Install of Reclos.- Ratio Transform	171	175	175	175	175
New Meters	96	90	90	90	90
Upgrade SCADA System	55	60	60	60	60
Environmental - PCB Mitigation	130	130			
Distribution Analysis Tools	183	50	75	50	50
Engineering Projects	58	60	60	60	60
Stevensville Reinforcement Project	156				
Storm Rebuilds	50	50	50	50	50
Projects Under Materiality Threshold	300	300	300	300	300
Information Technology Projects	563	330	780	500	500
General Expense Capital	509				
Total - FE	**4,580**	**3,380**	**5,585**	**3,780**	**3,805**
Distribution - Gananoque(EOP)					
Distribution Stations	65	60	60	60	60
Distribution Upgrades & Expansions	589	750	750	750	750
Distribution Transformers	67	70	70	70	70
Environmental - PCB Mitigation	150	150			
Projects Under Materiality Threshold	132	130	130	130	130
General Expense Capital	251				
Transportation Equipment				285	
Total - EOP	**1,254**	**1,160**	**1,010**	**1,295**	**1,010**
Total - FE/EOP	**$ 5,834**	**$ 4,540**	**$ 6,595**	**$ 5,075**	**$ 4,815**

(EP)

2. Rate Base

2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

30. Ref: Exhibit 2, Tab 2, Schedule 4

a) Please confirm that the data shown for 2011 are actuals. If this cannot be confirmed, please provide a table for 2011 that reflects actual 2011 capital projects.

b) Please confirm that the capital project expenditures for 2012 are still expected to be completed in 2012. If this cannot be confirmed, please provided a revised forecast for 2012, and if applicable, for 2013.

RESPONSE:

a) The data shown for 2011 are actuals.

b) The capital project expenditures for 2012 are still expected to be completed in 2012.

c) Not applicable as no question appears in paro. c).

(EP)

2. Rate Base

2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

31. Ref: Exhibit 2, Tab 2, Schedule 7

Please break out the CIAC shown in the table on page 1 for each year to show the contributions related due to the line relocations for the purpose of downtown beautification projects noted on lines 13-17.

RESPONSE:

The CIACs related to line relocations for downtown beautification projects were as follows:

- 2009 Actual: $232,000
- 2010 Actual: $66,770
- 2011 Actual: $134,850.

(SEC)

2. Rate Base
2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

1. [Ex.2/2/4]
   Please provide a table that shows the combined capital expenditures of CNPI – Fort Erie and EOP and CNPI – Fort Erie by USoA Account for 2009 through to 2013.

RESPONSE :

CAPITAL EXPENDITURE SUMMARY BY USoA ACCOUNT
2009 TO 2013
FE EOP and PC

OEB ACCT #	ACCOUNT DESCRIPTION	2009	2010	2011	2012	2013
1805	D Land	-	-	-	-	-
1806	D Land Right	10,689	28,022	34,858	23,000	76,052
1808	D Buildings & Fixtures				33,106	25,042
1820	D Station Equipment < 50KV	2,670,564	200,775	426,244	1,052,951	922,393
1830	D Poles,Towers&Fixtures	1,403,852	621,757	742,454	1,671,013	1,651,129
1835	D OH Cond & Devices	1,969,172	1,102,333	1,204,635	1,344,574	1,431,650
1840	D UG Conduit & Manholes	142,605	27,430	18,605	185,183	128,405
1845	D UG Cond & Devices	1,086,578	171,287	675,905	326,974	270,212
1850	D Line Transformers	492,731	566,157	740,959	577,841	605,673
1855	D Services	993,956	456,844	1,239,783	919,255	1,016,036
1860	D Meters	83,977	44,103	125,116	201,227	224,876
1865	D Other Install on Cust Prem	-	56,538	7,523	-	-
1908	GA Building&Fixtures	9,869	41,059	5,360	-	-
1910	Leasehold Improvements	60,390	-	333,424	25,000	53,000
1915	GA Office Furn & Equipment	10,294	7,241	21,613	3,063	3,130
1920	GA Comp Hardware	303,293	635,937	296,520	571,345	118,061
1925	Computer Software	383,178	1,454,600	548,419	399,592	558,053
1930	GA Transportation Equipment	295,034	68,805	148,406	650,000	390,000
1940	GA tools,shop&garage equip	9,971	4,911	2,810	22,197	30,343
1945	GA measure&test equip	3,371	13,234	-	21,755	26,355
1955	GA Comm Equipment	3,045	846	1,080	275,915	21,007
1960	GA Misc. Equip	15,344	27,277	-	210,926	213,183
1980	GA System Supv Equip	2,460	-	247	83,878	111,701
1995	Contributions & Grants	(1,500,974)	(847,014)	(856,493)	(517,034)	(425,000)
Total		**8,449,396**	**4,682,141**	**5,717,468**	**8,081,760**	**7,451,302**

(SEC)

2. Rate Base
2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

2. [Ex.2/2/1/p.4]
Please provide a table that shows the capital expenditures for each year between 2009 and 2013, by capital investment objective for:
a) CNPI - FOE and EOP
b) CNPI - Port Colborne
c) CNPI - FOE, EOP and Port Colborne

RESPONSE:

Tables with the requested information appear on the following pages. Most projects are undertaken to meet more than one objective, and totals shown for each objective are estimated breakdowns. Most projects also have some impact on safety, but totals displayed in the "Enhance Safety and Protect the Environment" pertain only to those undertaken for that specific purpose.

a) Fort Erie and EOP

Fort Erie & EOP					
	2009	**2010**	**2011**	**2012**	**2013**
Customer Demand	1,010,000	310,000	638,000	422,000	369,000
Replace Aging Assets	1,405,000	607,000	943,000	1,142,000	1,084,000
Improve System Reliability	1,236,000	592,000	919,000	1,104,000	1,016,000
Expand System Capacity	761,000	252,000	377,000	418,000	389,000
Install Metering	100,000	80,000	85,000	85,000	110,000
Distribution System Technology Upgrades	108,000	221,000	170,000	552,000	349,000
Improve Communications Systems					
Transportation	257,000	64,000	93,000	650,000	390,000
Maintain and Upgrade Facilities	55,000		290,000		
Enhance Safety and Protect the Environment				320,000	280,000
Total	**$ 4,939,000**	**$ 2,126,000**	**$ 3,514,000**	**$ 4,692,000**	**$ 4,081,000**

b) Port Colborne

Port Colborne					
	2009	**2010**	**2011**	**2012**	**2013**
Customer Demand	1,385,000	182,000	118,000	113,000	121,000
Replace Aging Assets	545,000	175,000	185,000	415,000	408,000
Improve System Reliability	621,000	242,000	308,000	458,000	523,000
Expand System Capacity	532,000	181,000	236,000	290,000	273,000
Install Metering	48,000	42,000	42,000	40,000	39,000
Distribution System Technology Upgrades		40,000		42,000	52,000
Enhance Safety and protect the Environment				200,000	150,000
Total	**$ 3,131,000**	**$ 862,000**	**$ 889,000**	**$ 1,558,000**	**$ 1,566,000**

c) Fort Erie, EOP, and Port Colborne

Fort Erie, Port Colborne and EOP					
	2009	**2010**	**2011**	**2012**	**2013**
Customer Demand	2,395,000	492,000	756,000	535,000	490,000
Replace Aging Assets	1,950,000	782,000	1,128,000	1,557,000	1,492,000
Improve System Reliability	1,857,000	834,000	1,227,000	1,562,000	1,539,000
Expand System Capacity	1,293,000	433,000	613,000	708,000	662,000
Install Metering	148,000	122,000	127,000	125,000	149,000
Distribution System Technology Upgrades	108,000	261,000	170,000	594,000	401,000
Improve Communications Systems					
Transportation	257,000	64,000	93,000	650,000	390,000
Maintain and Upgrade Facilities	55,000		290,000		
Enhance Safety and Protect the Environment				520,000	430,000
Total	**$ 8,070,000**	**$ 2,988,000**	**$ 4,403,000**	**$ 6,250,000**	**$ 5,647,000**

(SEC)

2. Rate Base
2.5 Is the CNPI – Fort Erie/Gananoque capital expenditure forecast for the test year appropriate?

3. [Ex.2/2/5/p.29]
Regarding, 2013 'Distribution Analysis Tools Project', please provide a breakdown of the costs for the 2013 Test Year.

RESPONSE :

101140 *Distribution Analysis Tools Projects* 2013 Projection is broken down as follows:

Item	Description	Amount
1	System implementation	$ 83,600
2	Data collection and verification	$ 12,400
3	Computer hardware and software purchases	$ 72,800
4	Distribution Asset Management Program (DAMP)	$ 14,200
TOTAL		**$ 183,000**

2. Rate Base

2.6
Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

(OEB)

Rate Base

Issue 2.6
Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

11. Ref: E2/T2/S11, p 5 – 6 – Overhead Services
E3/T2/S2 Appendix A, Table 7 & 8 – Load Forecast

On page 5 CNPI – PC shows capital expenditures of $71,000 in 2010 actual, $200,000 in 2011 actual (increase of 182%), $116,000 in the 2012 bridge year and $140,000 in the 2013 test year.

CNPI shows capital expenditures of $51,000 in 2010 actual, $135,000 in 2011 (165% increase), $122,000 in the 2012 bridge year and $125,000 in the 2013 test year. Costs prior to 2010 Overhead and Underground Service costs were aggregated under the category of new service lines. On page 6 under either category CNPI states that:

> *Projects in this classification are undertaken to install overhead facilities for service new customers or upgrade existing service lines in response to customer load growth. Projects in this category are customer-driven and cannot be deferred*

On page 11 and 12 E3/T2/S2, Appendix A CNPI shows a negative growth in customer numbers for 2011 actual and a decline in kW consumption for the Residential and GS<50 kW and USL customer classes. The GS>50, Street light and Sentinel light customer classes show significant load growth. Board staff further notes that CNPI has forecasted zero or negative load growth for all rate classes in the 2012 bridge and 2013 test years.

a) Please reconcile the above statement by CNPI for each category in E2/T2/S11 with the limited actual and forecast load growth and decline in customer numbers.
b) Please provide the up-to-date spending in this category.

RESPONSE:

a) There are a number of reconciling matters that contribute to the apparent contradiction of the two subject matters. First, from a customer projection point of view, CNPI will likely have some change-over of customers. In the normal course of events, some customers will cease to exist and others will connect to the system. For example, old houses will be disconnected and demolished and new homes will be constructed and new subdivisions developed.

Another activity covered under this budget is the upgrading of existing services. A common activity is to see older homes and commercial buildings upgrade and/or relocate their services. Frequently, older homes will upgrade from a 30 or 60 ampere service to a 100 ampere service.

Each of these activities contributes to the development of the forecasted amount.

b) CNPI has spent $32,770 as of June 30, 2012.

(OEB)

Rate Base

Issue 2.6
Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

12. Ref: E2/T2/S11, p 13 – Barrick Station Projects

CNPI is showing a capital expenditure of $144,000 in the 2012 bridge year and $179,000 in the 2013 test year. CNPI stated the following reasons:

> *Barrick DS is the oldest distribution substation in Port Colborne, being about 45 years old. It is located in a residential neighbourhood and consists of a single 27.6 kV – 4.16 kV power transformer and indoor switchgear contained in a building designed to look like a house. The switchgear and associated relaying is of an older design and is nearing the end of its useful life. Forecasted expenditures for 2012 Bridge Year and 2013 Test Year are for the replacement of the switchgear with a new lineup that meets modern design standards (such as Arc Proof ratings) and microprocessor-based protection systems. This project will be undertaken over 2012 and 2013 and will improve system security and safety by replacing aged equipment.*

a) Please provide a list of all system elements of the Barrick DS (i.e. Transformer, Switchgear, and Protection System) including the respective age and condition of the element. Please elaborate on the overall condition of the DS and provide an estimate as to when this transformer might need to be replaced.
b) Please elaborate on the impact on CNPI – PC's distribution system if this project were to be deferred.

RESPONSE:

a) The major components at Barrick DS are the power transformer, switchgear, protection system, primary cables (27.6 kV and 4.16 kV), and the building/civil structures. All components were manufactured or constructed in 1967, so all components are 45 years old.

The 4.16 kV switchgear is presently the most significant concern as it is in deteriorating condition, and there have been a few instances in the past few years where breakers have not operated appropriately and have required repairs. The switchgear is of an older design and spare parts are not readily available.

The power transformer is in fair condition, based on dissolved gas analysis. However, it is of a unique design because of the presence of a pothead-type termination chamber for incoming paper-insulated lead-covered (PILC) power cables. It is estimated that the power transformer will require replacement within five years.

The power cables are in fair condition, but some cables are PILC-type and are unique on CNPI distribution systems. Because the cables are partially in duct and partially direct-buried, a cable failure would result in a lengthy outage while replacement is carried out.

The building itself is in good condition, and will require some minor repairs and upgrades in the next few years. However, there is presently no oil containment system at the substation, so there is a risk that an oil spill would not be immediately contained. Underground power cables are only partially enclosed in conduit. Future station upgrades would include the installation of an oil containment system and blast walls around the power transformer to meet modern standards, as well as the installation of underground conduit to fully enclose underground power cables.

In terms of the overall condition of Barrick DS, the station is nearing the end of its useful life, though some major components are in poorer shape than others. As noted above, at this time, the switchgear is the most significant concern. CNPI-PC has adopted a prudent, staged approach to upgrading

this station, where the switchgear will be replaced in 2012-2013 and the remainder of the station in the next few years. A factor in the timing of the station upgrade is loading. Barrick DS and Jefferson DS provide backup capability for each other, and during the Summer of 2012 the combined peak load at the two substations exceeded the peak continuous capacity of either power transformer.

b) There would be a negative impact on the security of the PC distribution system should the switchgear upgrade project be deferred. The condition of the switchgear and its history are such that a deferral would greatly increase the risk of a major failure that would result in the station being out of service for a lengthy period of time. If the failure were to occur during peak loading periods, this would stress the feeders and transformer at the backup station, Jefferson DS. These occurrences would negatively impact the reliability to customers in Port Colborne.

(OEB)

Rate Base

Issue 2.6
Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

13. Ref: E2/T2/S11, p 15 – 16 – 43M11 Refurbishment Project

On page 15 CNPI – PC states shows new capital expenditures of $230,000 in the 2012 bridge year and $130,000 in the 2013 test year. CNPI states that this project is to rebuild sections of a feeder that are in deteriorating condition. CNPI also states that this project will relocate these sections to roadway allowances to facilitate better access for maintenance purposes.

a) Please provide further explanation on the condition of the feeder and provide a business case if one exists.
b) Please elaborate on the impact on CNPI – PC's distribution system if this project were to be deferred.

RESPONSE:

a) Below please find a description of the feeder condition:

- This line is over 40 years old.
- There is a 1.5 km section of the line located off road in a swamp.
- Some of the poles were rotten.
- In 2009, 6 poles failed in a major storm. 15 poles and conductors had to be removed for safety reasons.
- This line section is an important tie line between feeders M11 and M12.
- The other section of this line is the supply source for some significant industrial loads.

Accordingly, the completion of this project will improve overall system reliability.

b) If this project were to be deferred, the Port Colborne distribution system will lose an important feeder tie line and the customers may face prolonged outages during system events. The overall system reliability will be negatively impacted.

(OEB)

Rate Base

Issue 2.6
Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

14. Ref: E2/T3/S2, p.2 – Forecast Capital Expenditure

CNPI - PC provided a preliminary capital expenditure budget for the years 2013 through 2015.

a) Board staff notes that the forecasted capital budget for the 2013 includes General Expense Capital. Please explain if CNPI has taken into account the proposed changes to its capitalization policy effective January 1, 2013.
b) If not, why not.
c) Please expand and re-file the table on E2/T3/S2/p.2 to include a forecast of the capital budget for the years 2016 and 2017 rate years.

RESPONSE:

a) As outlined in Exhibit 11, CNPI – PC is not seeking to recover General Expense Capital in its 2013 capital expenditures forecast. CNPI is proposing to change the overhead capitalization policy effective January 1, 2013.

b) Not applicable.

c)

5-Year Capital Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast
Port Colborne					
Barrick Station Projects	179				1,300
Killaly Station Projects		300			
Catharine Station Projects			300		
Distribution Upgrades & Expansions	412	520	520	520	520
Overhead Service Lines	130	130	130	130	130
Underground Service Lines	105	100	100	100	100
Distribution Transformers	120	120	120	120	120
Install of Reclos.- Ratio Transform	97	60	60	60	60
Storm Rebuilds	52	50	50	50	50
New Meters	75	60	60	60	60
Environmental - PCB Mitigation	150	150			
Poletrans Replacement	108	55			
Projects Under Materiality Threshold	123	125	125	125	125
General Expense Capital	352				
Total	**1,903**	**1,670**	**1,465**	**1,165**	**2,465**

(EP)

2. Rate Base

2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

32. Ref: Exhibit 2, Tab 2, Schedule 10

a) Please confirm that the data shown for 2011 are actuals. If this cannot be confirmed, please provide a table for 2011 that reflects actual 2011 capital projects.

b) Please confirm that the capital project expenditures for 2012 are still expected to be completed in 2012. If this cannot be confirmed, please provided a revised forecast for 2012, and if applicable, for 2013.

RESPONSE:

a) The data shown for 2011 are actuals.

b) The capital project expenditures for 2012 are still expected to be completed in 2012.

(EP)

2. Rate Base

2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

33. Ref: Exhibit 2, Tab 2, Schedule 12

Please break out the CIAC shown in the table on page 1 for each of 2010 and 2011 to show the contributions related due to the line relocations for the purpose of downtown beautification projects noted on lines 15-19.

RESPONSE:

The CIACs related to the line relocations for downtown beautification projects were as follows:

- 2010 Actual: $70,000
- 2011 Actual: $133,190

(SEC)

2. Rate Base
2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

4. [Ex.2/2/7/p.1]
Please provide the 2012 year-to-date contributions in aid of construction for CNPI-Port Colborne.

RESPONSE:

The contributions in aid of construction for the period ending June 30, 2012 are as follows:

CNPI - FE/EOP	$232,090
CNPI – PC	$79,140

(SEC)

2. Rate Base
2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

5. [Ex.2/2/11/p.5]
With respect to poll replacement in CNPI-Port Colborne:
    1) How many polls does the Applicant forecast to replace in each of 2012 and 2013?
    2) How many polls has it replaced year-to-date?

RESPONSE:

1) CNPI expects to replace 100 poles in 2012 and 120 poles in 2013.

2) CNPI has replaced 41 poles to date in 2012.

(SEC)

2. Rate Base
2.6 Is the CNPI – Port Colborne capital expenditure forecast for the test year appropriate?

6. [Ex.2/2/12/p.1]
Please provide the 2012 year-to-date contributions in aid of construction for CNPI-Port Colborne.

RESPONSE:

The contributions in aid of construction for the period ending June 30, 2012 are as follows:

CNPI - FE/EOP	$232,090
CNPI – PC	$79,140

Canadian Niagara Power Inc.

EB-2012-0112

Response to Load Forecast and Operating Revenue Interrogatories

3. Load Forecast and Operating Revenue

3.1
Is the load forecast methodology including weather normalization appropriate?

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

15. Ref: E1/T1/S1 p. 1 – Distribution Revenue Overview – FE/EOP

On page 1 CNPI provided an overview of distribution revenue for the Fort Erie and Gananoque service territory under the CGAAP accounting standard. Please provide the same table under ASPE and show the transition year under both standards.

RESPONSE:

The reference for Board Staff Interrogatory No. 15 ought to read E3/T1/S1 p. 1.

The overview of distribution revenue referenced here is the revenue derived from the existing, or previous, fixed and variable distribution charges for the delivery of electricity. The amounts recorded would be the same whether reported in CGAAP or ASPE.

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

16. Ref: E1/T1/S2 p. 1 – Distribution Revenue Overview – PC

On page 1 CNPI provided an overview of distribution revenue for the Port Colborne service territory under the CGAAP accounting standard. Please provide the same table under ASPE and show the transition year under both standards.

RESPONSE:

The reference for Board Staff Interrogatory No. 16 ought to read E3/T1/S2 p. 1.

The overview of distribution revenue referenced here is the revenue derived from the existing, or previous, fixed and variable distribution charges for the delivery of electricity. The amounts recorded would be the same whether reported in CGAAP or ASPE.

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

17. Ref: E3/T2/S1, Appendix A – Weather Normalized Load Forecast

CNPI used a Normalized Average use (NAC) methodology to determine a weather normal load forecast. On page 1, CNPI states that "while it may be possible to estimate a regression model using wholesale data for at least two of the three CNPI service areas, analysis suggests there are extenuating circumstances that would advise against using a Wholesale kWh based regression model".

a) Did CNPI attempt to run regression models for one or more of CNPI's service territories? If so, please provide any preliminary test results using a regression model for any or all of the three service territories and explain the difference in outcome to the NAC methodology.

RESPONSE:

a) Yes. A regression model was attempted for EOP using wholesale purchases.

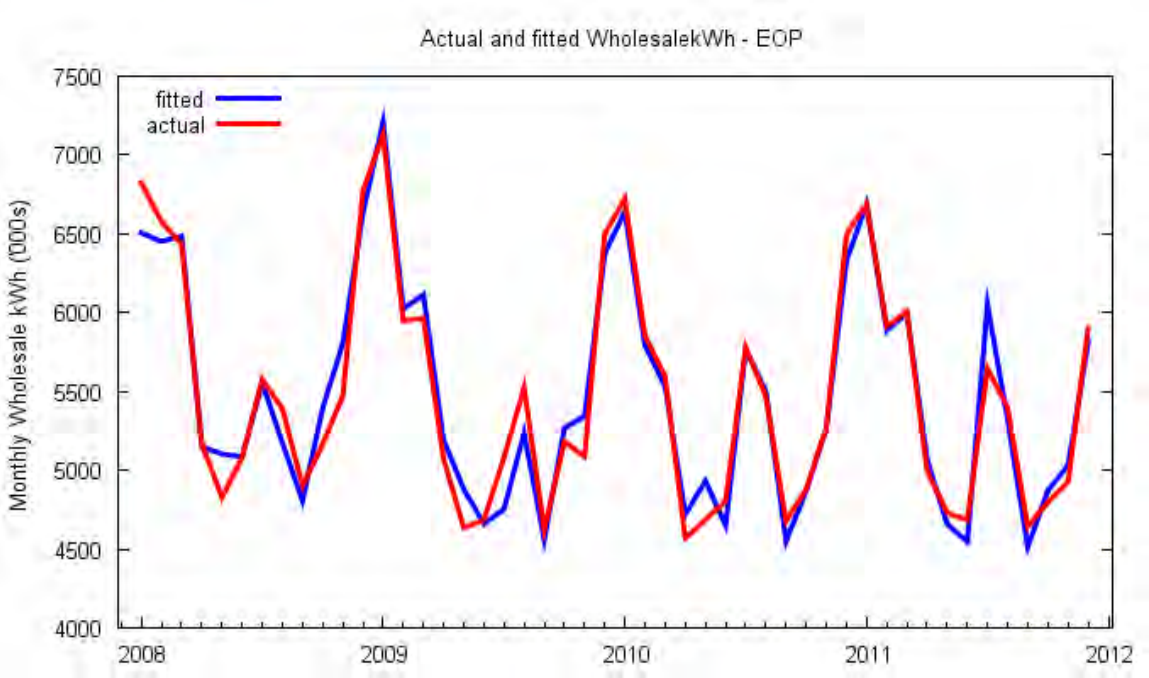
The resulting model and regression statistics are displayed below:

EOP Wholesale Regression Model: OLS, using observations 2008:01-2011:12 (T = 48)
Dependent variable: WholesalekWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-584645	1.21868e+06	-0.4797	0.63390	
HDD	3478.68	142.715	24.3750	<0.00001	***
CDD	9778.81	714.385	13.6884	<0.00001	***
KngFTE	24798	12728.7	1.9482	0.05810	*
Monthdays	126054	31421.1	4.0118	0.00024	***
time	-9224.52	1960.31	-4.7056	0.00003	***

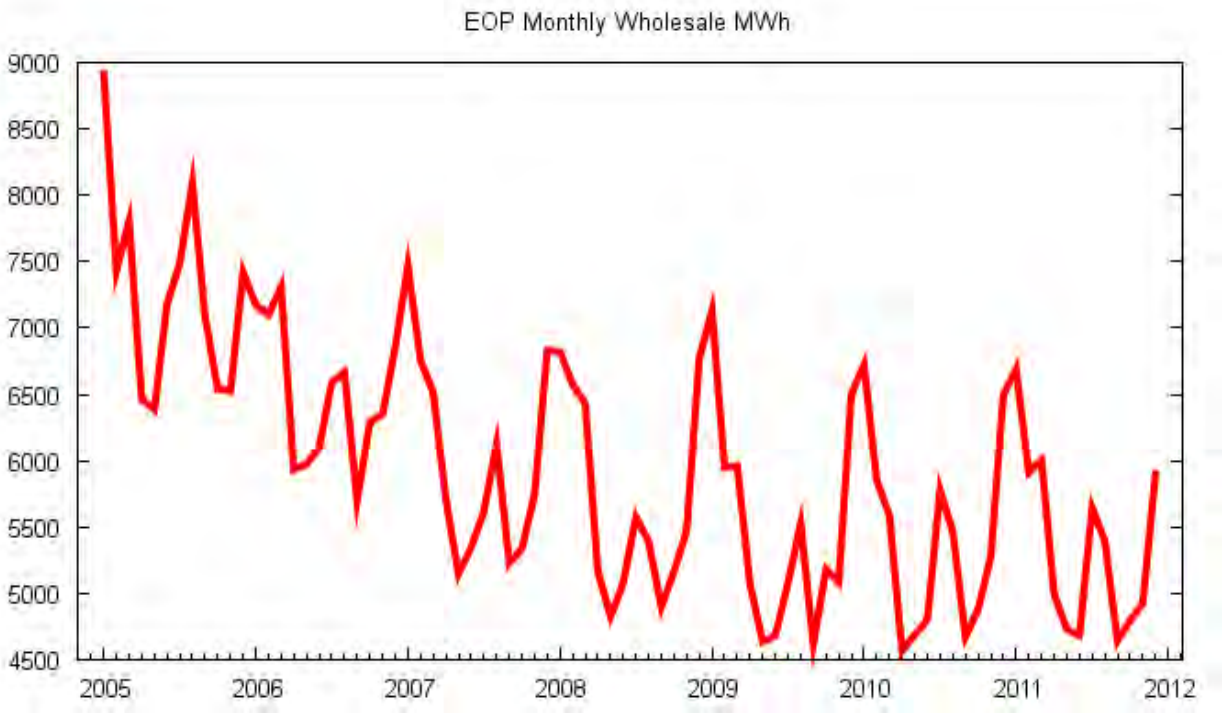
Mean dependent var	5474422	S.D. dependent var	719921.9
Sum squared resid	1.23e+12	S.E. of regression	171458.1
R-squared	0.949313	Adjusted R-squared	0.943279
F(5, 42)	157.3230	P-value(F)	4.65e-26
Log-likelihood	-643.4048	Akaike criterion	1298.810
Schwarz criterion	1310.037	Hannan-Quinn	1303.052
rho	0.113392	Durbin-Watson	1.687158

As can be seen from the above statistics and the chart below, the regression provides a good fit to the data.



This regression analysis is restricted to the most recent 4 years of historic data, from 2008 to 2011. This avoids the period of very large declines in

wholesale purchases that can be seen in the charts on page 3 of E3/T2/S2/Appendix A and reproduced below.



However, even though restricting the analysis to the most recent 4 years avoids the precipitous declines of the years prior to 2008, wholesale kWh purchases continued to decline in each year from 2008 to 2011, primarily due to the continued contraction of the GS>50 class. This is illustrated in Table 2 on page 6 of E3/T2/S2/Appendix A. Wholesale kWh continued to decline in each year and declined by 3.85 million kWh from 2008 to 2011, or on average about 1.9% per year. Residential kWh declined by 0.7% per year over the same period, and GS<50 and GS>50 declined by –2.3% and –3.3% per year, respectively. Therefore, it was decided that using the wholesale model approach, even when restricted to the most recent 48 months of historical data, would attribute too much decline to the residential class.

As outlined in on page 2 of E3/T2/S2/Appendix A, a “net wholesale” approach was also explored. This model was not found to have regression statistics that were sufficiently robust to use. Therefore, the decision was made to opt for a normalized average use per customer (“NAC”) approach, as explained on pp.1-6 of E3/T2/S2/Appendix A. A regression model and statistics for the “net wholesale” approach tried for EOP is reproduced below.

Model 42:OLS, using observations 2008:01-2011:12 (T = 48)
Dependent variable: NetWholekWh

	Coefficient	*Std. Error*	*t-ratio*	*p-value*	
const	-586281	1.47104e+06	-0.3985	0.69215	
HDD	3418.93	275.99	12.3879	<0.00001	***
CDD	9922.24	1369.79	7.2436	<0.00001	***
KngFTE	51833.5	23028.2	2.2509	0.02944	**

Mean dependent var	3973419	S.D. dependent var	718270.7
Sum squared resid	5.02e+12	S.E. of regression	337910.6
R-squared	0.792804	Adjusted R-squared	0.778677
F(3, 44)	56.11965	P-value(F)	4.40e-15
Log-likelihood	-677.0865	Akaike criterion	1362.173
Schwarz criterion	1369.658	Hannan-Quinn	1365.002
rho	-0.088160	Durbin-Watson	2.134682

The primary difference in outcome between using the wholesale kWh regression models and the NAC approach is that NAC isolates the decline in load to those classes where average use per customer has declined significantly whereas the wholesale kWh regression would allocate the decline across all classes.

Similar issues were present for Fort Erie, which also saw fairly significant declines in GS>50 (see Table 1, page 5, E3/T2/S2/Appendix A). For Port Colborne, a wholesale model with sufficiently robust regression statistics was not obtainable. This may be due to the very large industrial load (in some

years in excess of 50% of total purchases) that often varies significantly from year-to-year.

Given the extenuating circumstances, it was thought that the NAC approach was more prudent, and this was the approach that was adopted.

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

18. Ref: E3/T2/S1, Appendix A, Table 1 and 8 - Weather Normalized Load Forecast

On page 12, CNPI states: "*For non-weather sensitive classes, no normalization is used for historical consumption. Forecast consumption is based on the most recent year's use per customer and the forecast customers in each class*."

Referencing to Table 8 of the above evidence, Board staff notes that the 2012 and 2013 consumption forecasts are calculated using average of growth rate percentages for the period from 2007 to 2011.

a) Please explain the methodology that CNPI has used to forecast the consumptions for non-weather sensitive classes.

b) If CNPI has used an arithmetic average to calculate percentages for the period from 2007 to 2011, please show the average used to determine the kWh load forecast.

c) Please update and file with the Board a revised load forecast for the 2012 bridge and 2013 test year using a simple linear tend method and calculate the variance from the proposed forecast consumption for 2012 and 2013.

RESPONSE:

a) As indicated on page 12 of E3/T2/S1/Appendix A, the non-weather sensitive classes forecasts (that is, forecasts for the GS>50, lighting and USL classes) are based on the most recent [historical] year's use per customer and the forecast customers in each class. This is clearly seen for all street lighting, sentinel lighting and USL classes in all service areas where no change in customer connections are forecast. For GS>50, the EOP service territory has

forecast a loss of 2 customers in 2012 and the same number of customers in 2013. Therefore, there is a decline in forecast kWh in 2012 as the number of customers declines to 25 (multiplied by the average use per customer (in 2011) of 657,397.3.

For Fort Erie and Port Colborne, a similar approach has been used for the GS>50 classes except that, as explained on pp. 13-14, two large customers are leaving the system. Since these are extraordinary events, an adjustment to the class has been made, as outlined in Table 10. In the case of Port Colborne, the one customer accounts for an annual consumption of 33 million kWh, almost one-third of total class consumption.

b) CNPI used an arithmetic average to calculate a normalized annual average use per customer ("NAC") for the Residential and GS<50 kW classes; that is, classes that are considered weather sensitive. This approach was not used for non-weather sensitive classes. As outlined on p.8 of E3/T2/S1/Appendix A, an arithmetic five year average from 2007-2011 was used to define NAC for Residential and GS<50 kW classes for all service areas except EOP. For EOP, due to a significant change in the GS<50 kW class, the 2005-2008 arithmetic average is used to determine the NAC for 2007 and 2008, and the 2009-2011 arithmetic average is used to determine NAC for post-2009 consumption. These averages are shown in Table 6 on page 10 and in Table A1 on page 14.

c) See below:

CNPI Use per Customer

	Gananoque		Fort Erie		Port Colborne	
Date	Res	GS<50	Res	GS<50	Res	GS<50
2005		34,829				
2006		34,647				
2007	9,574	33,721	8,086	32,788	8,032	28,152
2008	9,580	32,650	7,888	28,858	7,855	27,454
2009	9,538	31,561	7,851	28,300	7,716	25,362
2010	9,228	31,077	7,996	28,855	7,884	25,369
2011	9,337	30,996	7,939	28,830	7,844	26,842
Simple Avg						
2007-2011	9,451		7,952	29,527	7,866	26,636
2005-2008		33,962				
2009-2011		31,211				
Linear Trend						
2007-2011	9,121		7,878	26,359	7,728	24,754
2005-2008		29,110				
2009-2011		30,363				

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

19. Ref: E3/T2/S1, Appendix A - Weather Normalized Load Forecast for GS<50 – EOP

On page 8 CNPI states:

> *For the weather sensitive Residential and GS<50 classes, a normalized average use per customer (NAC) is calculated. The five year (2007-2011) average annual use per customer is used to define NAC for these classes, except for the GS<50 class for EOP. For this class, the 2009-2011average is used for normalizing historical 2009-2011 consumption and for forecasting 2012 and 2013. The 2005-2008 average[1] is used to normalize the historic consumption 2007 to 2008. This is due to the fact that use per customer in this class has changed, as can be seen in Table 5 and in the Appendix.*

a) Please confirm that the 2012 and 2013 forecast is based on the average normalized historical consumption 2009-2011.
b) Please provide a load forecast for the GS<50 class using the five year (2007-2011) average annual use per customer, similar to the methodology used for the residential rate class.

RESPONSE:

a) Confirmed.

b) Please see information below.

CNPI Use per Customer

Gananoque

Date	Res	GS<50
2005		34,829
2006		34,647
2007	9,574	33,721
2008	9,580	32,650
2009	9,538	31,561
2010	9,228	31,077
2011	9,337	30,996
Simple Avg		
2007-2011	9,451	**32,001**
2005-2008		33,962
2009-2011		31,211

2013 customer Forecast	394
Forecast based on 2009-2011 NAC	12,297,262
Forecast based on 2007-2011 NAC	12,608,417

(OEB)

Load Forecast and Operating Revenue

Issue 3.1
Is the load forecast methodology including weather normalization appropriate?

20. Ref: **E3/T2/S1, Appendix A**

If CNPI has in the past completed internal annual forecast please provide the historical annual load forecast for the 2009, 2010 and 2011 rate years and corresponding actuals for those years for each of the three service areas.

a) Please also provide the variance from those actuals.

RESPONSE:

CNPI does not complete a weather normalized forecast for non-rebasing years. CNPI uses its historical actuals as a basis for forecasting its annual distribution revenues by charge type and customer class. For 2009, the load forecast would have been the Board approved forecast arising from the 2009 EDR; EB-2008-0222, EB-2008-0223 and EB-2008-0224.

In the absence of weather normalized load data, CNPI relies on intuitively forecasted loads based on historical trending and local knowledge. The table below compares CNPI's annual forecast to actual.

a) Please see the following tables:

Fort Erie										
Customer Class	UOM	2009 EDR	2009 Actual	Variance	2010 Forecast	2010 Actual	Variance	2011 Forecast	2011 Actual	Variance
Residential	kWh	115,322,011	111,596,385	(3,725,626)	114,325,452	114,051,203	(274,249)	115,670,875	113,713,474	(1,957,401)
GS < 50 kW	kWh	37,747,136	33,818,908	(3,928,228)	34,802,178	34,886,295	84,117	37,975,061	34,941,917	(3,033,144)
GS > 50 kW	kWh	147,729,800	127,215,229	(20,514,571)	142,462,680	129,724,134	(12,738,546)	130,849,690	124,961,992	(5,887,698)
	kW	399,198	366,305	(32,893)	365,910	368,891	2,981	363,179	342,446	(20,733)
USL	kWh	713,710	644,529	(69,181)	670,677	668,731	(1,946)	644,529	788,656	144,127
Sen. Lgt.	kWh	768,334	684,717	(83,617)	788,247	709,444	(78,803)	685,193	687,242	2,049
	kW	2,423	2,257	(166)	2,347	2,508	161	2,403	2,110	(293)
Str. Lgt.	kWh	2,197,378	2,164,346	(33,032)	2,243,401	1,967,174	(276,227)	2,169,595	2,136,308	(33,287)
	kW	7,023	7,658	635	6,783	7,078	295	7,119	5,996	(1,123)

Gananoque										
Customer Class	UOM	2009 EDR	2009 Actual	Variance	2010 Forecast	2010 Actual	Variance	2011 Forecast	2011 Actual	Variance
Residential	kWh	29,586,254	29,586,436	182	29,801,267	28,625,240	(1,176,027)	29,718,191	29,052,645	(665,546)
GS < 50 kW	kWh	14,048,011	12,624,543	(1,423,468)	14,130,597	12,306,415	(1,824,182)	13,383,349	12,351,830	(1,031,519)
GS > 50 kW	kWh	18,614,527	17,770,088	(844,439)	16,789,123	17,583,459	794,336	17,408,000	17,421,029	13,029
	kW	58,100	54,592	(3,508)	52,578	58,146	5,568	54,162	48,371	(5,791)
USL	kWh	94,602	159,318	64,716	93,955	160,435	66,480	156,000	157,458	1,458
Sen. Lgt.	kWh	80,618	70,625	(9,993)	81,478	67,961	(13,517)	70,616	60,462	(10,154)
	kW	241	232	(9)	241	240	(1)	228	184	(44)
Str. Lgt.	kWh	555,619	554,734	(885)	580,612	452,692	(127,920)	555,872	551,511	(4,361)
	kW	1,662	1,680	18	1,662	1,749	87	1,677	1,674	(3)

Port Colborne										
Customer Class	UOM	2009 EDR	2009 Actual	Variance	2010 Forecast	2010 Actual	Variance	2011 Forecast	2011 Actual	Variance
Residential	kWh	64,972,406	63,037,704	(1,934,702)	64,705,236	64,264,350	(440,886)	64,956,628	64,016,802	(939,826)
GS < 50 kW	kWh	25,831,151	23,155,644	(2,675,507)	25,384,902	22,871,401	(2,513,501)	25,105,014	24,184,539	(920,475)
GS > 50 kW	kWh	99,392,250	101,400,949	2,008,699	105,085,537	102,093,247	(2,992,290)	104,000,000	112,993,161	8,993,161
	kW	377,959	358,674	(19,285)	393,944	379,400	(14,544)	404,000	374,429	(29,571)
USL	kWh	581,173	780,483	199,310	582,473	695,082	112,609	780,486	581,815	(198,671)
Sen. Lgt.	kWh	12,725	11,668	(1,057)	12,415	12,475	60	11,664	13,332	1,668
	kW	38	38	-	38	47	9	40	40	-
Str. Lgt.	kWh	1,792,552	1,824,487	31,935	1,845,879	1,628,021	(217,858)	1,826,200	1,787,583	(38,617)
	kW	5,433	4,990	(443)	5,443	5,657	214	4,963	4,119	(844)

(EP)

3. Load Forecast and Operating Revenue

3.1 Is the load forecast methodology including weather normalization appropriate?

34. Ref: Exhibit 3, Tab 2, Schedule 1, page 7

a) Did the Ontario Gaming and Lottery Corporation close its facility in Fort Erie on April 30, 2012? If not, please provide the current status of this customer and any revised closure date that has been announced.

b) Please provide any information related to potential new customers in the GS 50 to 4,999 kW class in any of the service areas that have been announced, and are not included in the forecast.

RESPONSE:

a) Yes, the Ontario Gaming and Lottery Corporation closed its facility in Fort Erie on April 30, 2012. In addition, the Fort Erie race track which was associated with the facility, announced that it too will cease operations in the fall of 2012, one additional loss of electrical load and a major employer.

b) CNPI is not aware of any new GS > 50 customers in any of its service territories.

(VECC)

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalization appropriate?

1. Reference: Exhibit 3, Tab 2, Schedule 2, page 2
Exhibit 3, Tab 2, Schedule 2, Appendix A, page 5

a) Please provide a schedule that sets out for Port Colborne's GS>50 class for the years 2007-2011 the number of customers, total kWhs and average use per customer – where Jungbunzlauer is excluded from all three items.

RESPONSE:

Port Colborne GS>50 Class, Annual kWh, Customers, and Use Per Customer - Exclusive of Jungbunzlauer

Year	kWh	Cust #[1]	Use Per Cust
2007	85,750,072	78	1,099,360
2008	77,354,486	76	1,017,822
2009	85,708,870	79	1,017,822
2010	78,869,871	80	985,873
2011	79,635,669	75	1,061,809

[1] Annual Average.

(VECC)

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalization appropriate?

2. Reference: Exhibit 3, Tab 2, Schedule 2, Appendix A, pages 2 and 4

a) The Elenchus Report suggests (both pages 2 & 4) that if a wholesale kWh method was used then the decline in wholesale purchases would necessarily be reflected in the usage for all customer classes. Please explain why this would be the case and why the allocation of the total purchases power to customer classes could not be done in a manner that attributes an appropriate portion of the reduction to the GS>50 class.

b) Please provide the results of the regression analyses performed using (total) purchased wholesale load (i.e., the equations and the associated statistics) for each of FE, PC and EOP. Also using these equations, please provide a projection of total wholesale purchases (prior to any adjustments for CDM) for 2012 and 2013 for each service area.

c) Please provide the results of the regression analysis performed using "net wholesale load" for EOP, FE and PC (i.e., with the GS>50 class kWh removed), in terms of the estimated equations and the equations' statistics.

d) Were each of the following variables tested for inclusion in the regression models developed per part (c):
- Heating and Cooling Degree Days
- Number of Peak Hours in Month
- Customer Count/Population Variables
- Economic Variables such as GDP or Unemployment Rates?

If yes, please summarize the results in those cases where the variable does not appear in the final equation per part (c). If no, please provide analysis that tests these independent variables.

RESPONSE:

a) In general, the Elenchus consultant typically uses the historical share of each classes' share in wholesale purchases to allocate normalized and forecast wholesale purchases to each class. Allocation of wholesale purchases based on historical shares can be avoided if class specific models can be derived. However, the ability to do so is data dependent and is not always possible, as in the case of CNPI. To allocate "*the total purchases power to customer classes in a manner that attributes an appropriate portion of the reduction to the GS>50 class*" would require either an arbitrary method to do so, or a model forecasting the class shares. In the case of CNPI, it was thought that the Normalized Average Use Per Customer (NAC) approach would be more transparent and simpler, and less arbitrary than *ad hoc* adjustments.

b) Please see response to Board Staff 17 (a).

c) Please see response to Board Staff 17 (a).

d) Heating and cooling degree days and number of peak days in the month as well as number of days in the month were tested as explanatory variables. Economic variables such as full-time employment and employment were also tested. GDP and unemployment rates were not tested. The Elenchus consultant is unaware of any statistical agency that produces monthly regional GDP or monthly provincial GDP. Unemployment rates are not as robust as employment as they are also influenced by the participation rate, and therefore were not considered. Customer counts and population variables were also not tested. Customer counts have yielded very poor results in the past and in some previous cases before the Board have been noted to yield counterintuitive results. Population variables are generally not available in monthly format and are estimates, rather than observations in intercensal periods, which limit their usefulness.

(VECC)

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalization appropriate?

3. Reference: Exhibit 3, Tab 2, Schedule 2, Appendix A, page 8

   a) Please provide a schedule that sets out the actual HDD and CDD values for each of the three service areas for the years 2007-2011 inclusive along with the average of the five years for each service area.

   b) Based on the values provided in part (a), please comment on whether the lower annual average use values observed for the EOP customer classes in 2009-2011 is due to weather variations.

RESPONSE:

a) The following table displays actual HDD and CDD for 2007 to 2011 for Toronto Pearson, used for the Fort Erie, Port Colborne and Eastern Ontario Power service areas, along with the 5 year average, as requested.

Toronto Pearson

Year	HDD	CDD
2007	3,719.4	436.0
2008	3,836.0	275.7
2009	3,835.8	197.9
2010	3,500.9	439.6
2011	3,647.5	428.0
2007-11 Avg	3,707.9	355.4

b) It is unlikely that declining average use in the EOP service area from 2009 to 2011 is due to weather alone. In fact, 2009 had higher than average HDD (although much lower than average CDD) and 2010 and 2011 had higher than average CDD. However, we note that annual averages likely do not

adequately represent weather variation trends. It is clear that the EOP service area has been significantly affected by economic factors and that this is the primary reason for declining use.

(VECC)

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalization appropriate?

4. Reference: Exhibit 3, Tab 2, Schedule 2, Appendix A, pages12-13

   a) Please provide a schedule that for each of the non-weather sensitive classes in each of the three service areas sets out the actual kWhs using the most recent 12 months of data available and the average number of customers for each rate class over the same period. (Note: For FE, please exclude the usage and customer count for OLG Slots. Similarly, for PC, please exclude the usage and customer count associated with JBL.)

RESPONSE:

a) Please find the requested schedule below.

Actual kWh and Average Customers, Latest 12 Months (July 2011 - June 2012)							
Eastern Ontario Power							
GS>50 kWh	GS>50 Customers	Streetlight kWh	Streetlight Connections	Sentinel kWh	Sentinel Connections	USL kWh	USL Customers
17,337,808	25	552,115	622	54,601	58	157,521	6
Fort Erie							
GS>50 kWh[1]	GS>50 Customers[1]	Streetlight kWh	Streetlight Connections	Sentinel kWh	Sentinel Connections	USL kWh	USL Customers
114,618,084	123	2,290,100	3,074	685,594	862	807,339	19
Port Colborne							
GS>50 kWh[2]	GS>50 Customers[2]	Streetlight kWh	Streetlight Connections	Sentinel kWh	Sentinel Connections	USL kWh	USL Customers
81,288,610	75	1,888,540	1,987	13,287	39	574,030	14
[1] excluding OLG Slots							
[2] excluding JBL							

(VECC)

Load Forecast and Operating Revenue

3.1 Is the proposed load forecast methodology including weather normalization appropriate?

5. Reference: Exhibit 3, Tab 2, Schedule 2, Appendix A, page 13

   a) Please explain how the 2012 and 2013 kW values for the GS>50 class in the FE and PC service areas were determined.

RESPONSE:

a) Please refer to the response to Energy Probe Interrogatory No. 35.

3. Load Forecast and Operating Revenue

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

(EP)

3. Load Forecast and Operating Revenue

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

35. Ref: Exhibit 3, Tab 2, Schedule 2, Appendix A

Please explain how the kW forecasts for the GS > 50 kW classes shown in Table 9 have been calculated for 2012 and 2013. Please show any calculations used.

RESPONSE:

a) The kW forecast for the GS>50 kW classes is explained on page 13 of the Elenchus Report (Exhibit 3, Tab 2, Schedule 2, Appendix A). To recap, the kW for Eastern Ontario Power remains unchanged for 2012 and 2013 (i.e., remains at 2011 actual level). For Fort Erie, GS>50 kW is reduced by 8,196 kW in 2012, representing the May through December demand for OLG Slots. In 2013, the kW is reduced by an additional 2,919 kW representing January to April consumption of OLG slots. For Port Colborne, GS>50 kW is reduced by 62,765 kW, which is 75% of the 83,687 kW annual demand of JBL, which will cease to be a customer in 2013.

Monthly detail of these customers' consumption is shown in Table 10 on page 14 of the Elenchus Report (Exhibit 3, Tab 2, Schedule 2, Appendix A).

(EP)

3. Load Forecast and Operating Revenue

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

36. Ref: Exhibit 3, Tab 2, Schedule 2, Appendix A

a) Please provide a live Excel spreadsheet that contains all of the data used in the determination that the standard regression model approach is not possible or preferable.

b) Please provide monthly data for 2007 through 2010 in a live Excel spreadsheet for each of the distribution regions that includes the residential and GS<50 volumes and customers, along with the actual heating and cooling degree days.

c) Please provide a live Excel spreadsheet with the actual monthly heating and cooling degree days for the 2002 through 2011 period for each distribution region.

RESPONSE:

a) Please see attached excel spreadsheet "EPRF 36 (a).xls" which contains all available data for each of the service areas.

b) Provided in the response to part (a).

c) Please see attached excel spreadsheet "Pearson Degree Days 2002-2011.xls".

(VECC)

Load Forecast and Operating Revenue

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

6. Reference: Exhibit 3, Tab 1, Schedule 1, page 1
Exhibit 3, Tab 2, Schedule 1, page 1

a) Please clarify if the distribution revenues reported in each of the tables are net of (i.e., reduced by) the transformer ownership discount.

RESPONSE:

The distribution revenues reported in each of the tables are not net of the transformer ownership credit.

(VECC)

Load Forecast and Operating Revenue

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

7. Reference: Exhibit 3, Tab 2, Schedule 1, page 10
Exhibit 3, Tab 2, Schedule 2, page 2

a) Please confirm that Jungbunzlauer still plans to become a transmission customer in the fourth quarter of 2012.

RESPONSE:

Yes, Jungbunzlauer still plans to become a transmission customer in the fourth quarter of 2012.

(VECC)

Load Forecast and Operating Revenue

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

8. Reference: Exhibit 3, Tab 2, Schedule 2, Appendix A, page 11
Exhibit 3, Tab 2, Schedule 2, page 2

a) Please provide the actual customer count by customer class for each of the three service areas for the most recent month the data is available.

RESPONSE:

a) Please see the tables on the following page.

There appears to be some growth in the Gananoque and Port Colborne residential classification. This is partially the result of the smart meter initiative. Some residential customers, prior to the introduction of smart meters, had two meters; one for domestic load and one for electric heating. The introduction of smart meters necessitated the removal of one meter or the customer would have had two residential accounts. CNPI incentivized customers to remove one meter; not all customers opted for this option. This resulted in additional customer counts but not necessarily additional load.

The General Service less than 50 kW class in Port Colborne indicates growth. This customer classification is significantly impacted by boat services which are normally brief connections while boats in the Welland Canal undergo refit. As the accounts are reconciled the customer counts will drop.

Fort Erie	Per Application	As at June 30, 2012
Residential	14,433	14,415
GS < 50 kW	1,230	1,227
GS > 50 kW	124	123
USL	19	20
Sentinel Lighting	862	862
Street Lighting	3,074	3,074
Gananoque	Per Application	As at June 30, 2012
Residential	3,104	3,119
GS < 50 kW	403	403
GS > 50 kW	25	25
USL	6	6
Sentinel Lighting	58	58
Street Lighting	622	622
Port Colborne	Per Application	As at June 30, 2012
Residential	8,152	8,181
GS < 50 kW	888	902
GS > 50 kW	79	76
USL	14	14
Sentinel Lighting	41	41
Street Lighting	2,000	1,967

3. Load Forecast and Operating Revenue

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

(OEB)

Load Forecast and Operating Revenue

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

21. Ref: E3/T2/S2, Appendix A – CDM target reduction

a) Please explain how CNPI's CDM targets have been reflected in the proposed load forecast and confirm whether it is the net target or the gross target.
b) Please state how the CDM target has been allocated between FE/EOP and PC.

RESPONSE:

a) There is no adjustment made to CNPI's forecast for its CDM targets.

b) The CDM targets for CNPI Fort Erie/Gananoque and CNPI Port Colborne were established independently of each other; there is no allocation.

(EP)

3. Load Forecast and Operating Revenue

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

37. Ref: Exhibit 3, Tab 2, Schedule 2, Appendix A

a) How has the impact of CDM been reflected in the load forecast?

b) If there has not been any explicit adjustment for CDM in the 2013 forecast, does CNPI believe that the average use methodology adequately reflects CDM over the forecast period? Please elaborate.

a) How does CNPI propose to deal with any LRAM request if there is not an explicit forecast of CDM built into the volumes?

RESPONSE:

a) Please refer to Board Staff Interrogatory No. 21 part a).

b) Please refer to VECC Interrogatory No. 9.

c) Please refer to VECC Interrogatory No. 9.

(VECC)

Load Forecast and Operating Revenue

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

9. Reference: Exhibit 3, Tab 2, Schedule 2
Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), page 13

a) What are CNPI's CDM targets for EOP/FE and PC as set by the Board for 2011-2014?

b) Has CNPI included the impact of CDM programs (up to and including 2012 programs) in its Load Forecast?

c) If yes, please explain what program impacts (i.e., what years' program savings) have been reflected in the Load Forecast.

d) If the impacts of the 2011 and 2012 CDM programs are not reflected in the load forecast, please address the issues required as per the first full paragraph on page 13 of the Board's Guidelines.

e) Please provide a copy of the OPA's report on CNPI's 2011 CDM program savings for each of the three service areas.

RESPONSE:

a) CNPI's CDM targets for Fort Erie/Gananoque and Port Colborne as set by the Board for 2011-2014 are:

Fort Erie/Gananoque

Consumption	15,810,000 kWh
Peak Demand	4,070 kW

Port Colborne

Consumption	9,270,000 kWh
Peak Demand	2,330 kW

b) The impacts of CDM programs are not explicitly included in CNPI's load forecast.

c) Not applicable.

d) While CNPI has not explicitly included CDM in its forecast, a projected annual CDM target achievement has been compiled and is shown below.

Fort Erie/Gananoque	**UOM**	**2011**	**2012**	**2013**	**2014**
Cumulative Energy Target Achieved	kWh	838,481	2,934,682	7,651,135	15,810,000
Cumulative Peak Demand Target Achieved	kW	255	893	2,169	4,070
Port Colborne					
Cumulative Energy Target Achieved	kWh	491,633	1,720,715	4,486,150	9,270,000
Cumulative Peak Demand Target Achieved	kW	146	511	1,242	2,330

However, since the inception of the CDM targets, CNPI customer and load profile have changed. As discussed in Exhibit 3 Tab 1 and Exhibit 3 Tab 2, CNPI is losing or has lost its largest customer in Port Colborne and one of its larger customers in Fort Erie. As the review of this Application progresses, CNPI continues to lose industries with the announced closing of the horse racing industry in Fort Erie and its many supply chain customers; the announced closing of a large industrial customer dedicated to windmill fabrication; and a major employer in the pharmaceutical industry.

With this drastic change to its load profile CNPI believes that it has no choice but to petition the Ontario Energy Board for relief in way of reductions to its CDM targets.

In terms of the Board's report, specifically page 13, CNPI has to either revise its forecast to include the forecasted CDM reductions or follow the Board's guideline as stipulated in the second paragraph on page 13 of the Board's guideline.

e) Copies of the OPA's preliminary report for 2011 as well as the Q1 2012 Preliminary Results follow in this interrogatory.

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Draft 2011 Results Report. This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September.

Please note that the draft results within this report vary from the preliminary report for the following key reasons:

- Use of the iCON CRM system by evaluators provided more detail and documentation compared to previous years. As a result, Retrofit realization rates and net-to-gross ratios are higher than the initial conservative estimates.
- The Direct Install Lighting realization rate for demand savings was higher than expected resulting in almost double the reported demand savings.
- High Performance New Construction (Pre-2011 Program Completed in 2011) was previously provincially allocated, the data is now available at an LDC level
- Recent efforts to close out pre-2011 programs resulted in a thorough reporting of projects completed in 2011.
- More data submitted from retailers resulted in a large jump in coupons redeemed from Bi-Annual Retailer Events and Instant Coupon Booklets

At this point the results are still subject to change. The OPA is committed to ensuring that results are clearly understood and LDCs have the opportunity to review and provide feedback. To ensure that your inquiries can be directed to the appropriate OPA contact and addressed prior to the release of the final results, please e-mail a list of questions and/or concerns to LDC Support (LDC.Support@powerauthority.on.ca) with the subject line “Final 2011 Results: INSERT LDC NAME” by Tuesday August 14, 2012.

The Final 2011 Results Report will be available to all LDCs on or before Friday August 31, 2012. All results will be considered final for 2011, therefore any additional 2011 program activity not captured will be reported in the Final 2012 Results Report.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to another successful year ahead. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

Sincerely,

Andrew Pride

OPA-Contracted Province-Wide CDM Programs DRAFT 2011 Results

LDC: Canadian Niagara Power Inc.

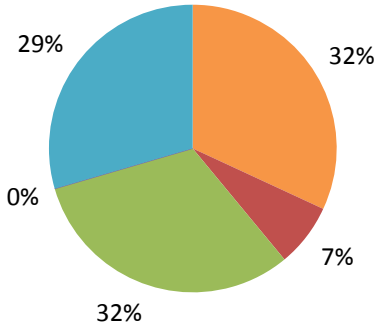
DRAFT Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.4	**4.2%**	**6.3%**
Net Cumulative Energy Savings (GWh)	1.3	**23.3%**	**23.3%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

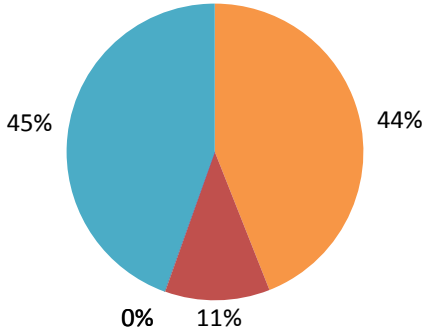
Scenario 2 = Assumes that demand response resources remain in your territory until 2014

Achievement by Sector

2011 Incremental Peak Demand Savings (MW)



2011 Incremental Energy Savings (GWh)

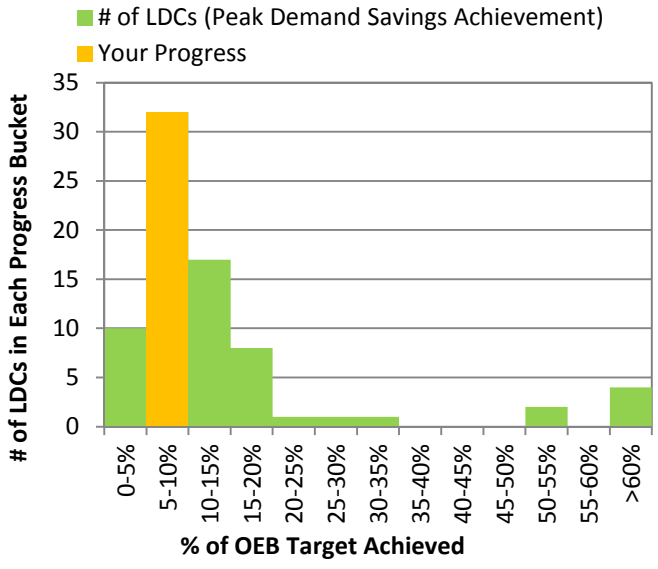


- Consumer Program Total
- Business Program Total
- Industrial Program Total
- Home Assistance Program Total
- Pre-2011 Programs completed in 2011 Total

Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

% of OEB Peak Demand Savings Target Achieved



% of OEB Energy Savings Target Achieved

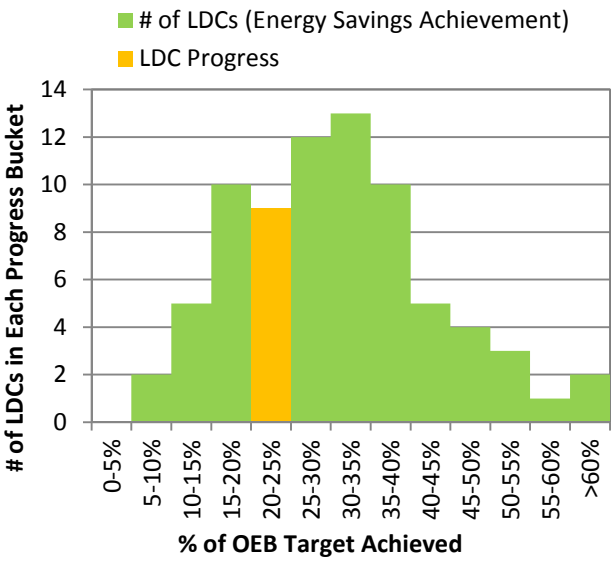


Table 1: Participation**

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	321
2	Appliance Exchange	Appliances	67
3	HVAC Incentives	Equipment	360
4	Conservation Instant Coupon Booklet	Products	2,501
5	Bi-Annual Retailer Event	Products	4,447
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects[1]	8
10	Direct Install Lighting	Projects	14
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	0
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects[1]	0
20	Demand Response 3	Facilities	1
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	16
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

*** Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[1] *Breakdown by sector to be provided in final results report*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers*

Table 3: Evaluation Findings

********** TO BE POPULATED WITH FINAL RESULTS **********

#	Initiative	OPA Key Evaluation Findings
Consumer Program		
1	Appliance Retirement	
2	Appliance Exchange	
3	HVAC Incentives	
4	Conservation Instant Coupon Booklet	
5	Bi-Annual Retailer Event	
6	Retailer Co-op	
7	Residential Demand Response	
8	Residential New Construction	
Business Program		
9	Efficiency: Equipment Replacement	
10	Direct Install Lighting	
11	Existing Building Commissioning Incentive	
12	New Construction and Major Renovation Incentive	
13	Energy Audit	
14	Commercial Demand Response (part of the Residential program schedule)	
15	Demand Response 3 (part of the Industrial program schedule)	
Industrial Program		
16	Process & System Upgrades	
17	Monitoring & Targeting	
18	Energy Manager	
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	
20	Demand Response 3	
Home Assistance Program		
21	Home Assistance Program	
Pre-2011 Programs completed in 2011		
22	Electricity Retrofit Incentive Program	
23	High Performance New Construction	
24	Toronto Comprehensive	
25	Multifamily Energy Efficiency Rebates	
26	Data Centre Incentive Program	
27	EnWin Green Suites	

Table 5: Summarized Program Results

Program	Gross Savings		Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	209	833,242	128	585,433	124	2,337,300
Business Program Total	32	192,858	29	152,247	26	599,889
Industrial Program Total	126	523	126	523	0	523
Home Assistance Program Total	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total	296	1,477,599	118	591,910	118	2,896,796
Total OPA Contracted Province-Wide CDM Programs	**663**	**2,504,222**	**401**	**1,330,113**	**268**	**5834508.2**

#	Initiative	Total Adjustments to Net Savings		Gross Savings		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	51%	52%	38	268,390	19	138,573	19	554,189
2	Appliance Exchange	51%	51%	10	13,641	5	6,999	1	23,665
3	HVAC Incentives	60%	60%	148	327,857	89	196,101	89	784,404
4	Conservation Instant Coupon Booklet	114%	111%	5	85,921	6	94,319	6	377,276
5	Bi-Annual Retailer Event	112%	110%	8	137,435	9	149,442	9	597,766
6	Retailer Co-op	n/a	n/a	0	0	0	0	0	0
7	Residential Demand Response	n/a	n/a	0	0	0	0	0	0
8	Residential New Construction	n/a	n/a	0	0	0	0	0	0
Business Program									
9	Efficiency: Equipment Replacement	66%	94%	18	152,574	13	114,842	13	458,359
10	Direct Install Lighting	163%	83%	14	40,284	15	37,406	13	141,530
11	Existing Building Commissioning Incentive	n/a	n/a	0	0	0	0	0	0
12	New Construction and Major Renovation Incentive	n/a	n/a	0	0	0	0	0	0
13	Energy Audit	n/a	n/a	0	0	0	0	0	0
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	0	0	0	0	0	0
15	Demand Response 3 (part of the Industrial program schedule)	n/a	n/a	0	0	0	0	0	0
Industrial Program									
16	Process & System Upgrades	n/a	n/a	0	0	0	0	0	0
17	Monitoring & Targeting	n/a	n/a	0	0	0	0	0	0
18	Energy Manager	n/a	n/a	0	0	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	n/a	n/a	0	0	0	0	0	0
20	Demand Response 3	n/a	n/a	126	523	126	523	0	523
Home Assistance Program									
21	Home Assistance Program	n/a	n/a	0	0	0	0	0	0
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	40%	40%	295	1,474,794	118	590,508	118	2,891,186
23	High Performance New Construction	50%	50%	1	2,805	0	1,402	0	5,610
24	Toronto Comprehensive	n/a	n/a	0	0	0	0	0	0
25	Multifamily Energy Efficiency Rebates	n/a	n/a	0	0	0	0	0	0
26	Data Centre Incentive Program	n/a	n/a	0	0	0	0	0	0
27	EnWin Green Suites	n/a	n/a	0	0	0	0	0	0

** Includes BOTH adjustments due to Realization Rate and Net-to-Gross Ratio; See "Methodology" tab for more information*

*** Please see "Methodology" tab for information regarding determining LDC-specific savings*

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.40	0.27	0.27	0.27
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.27
Canadian Niagara Power Inc. 2014 Annual CDM Capacity Target:				6.4
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				4.19%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	1.33	1.51	1.51	1.49	5.83
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					5.83
Canadian Niagara Power Inc. 2011-2014 Cumulative CDM Energy Target:					25.08
Verified Portion of Cumulative Energy Target Achieved (%):					23.26%
LDC Milestone submitted for 2011					-%
Variance					

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,209
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,176
4	Conservation Instant Coupon Booklet	Products[4]	544,778
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement[1]	Projects	2,918
10	Direct Installed Lighting	Projects	20,325
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	9
13	Energy Audit	Audits	13
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	1,471
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	548
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	1
27	EnWin Green Suites	Projects	3

[1] *Breakdown by sector to be provided in final results report*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers*

[4] *196,396 valid coupons redeemed*

[5] *369,446 valid coupons redeemed*

Table P2: Province-Wide Results

Program	Gross Savings		Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	65,735	191,747,475	44,531	132,655,311	33,256	530,225,875
Business Program Total	78,590	289,450,685	68,564	226,789,418	45,168	881,015,070
Industrial Program Total	71,783	2,978,648	71,783	2,978,648	0	2,978,648
Home Assistance Program Total	4	56,119	2	39,283	0	0
Pre-2011 Programs completed in 2011 Total	64,939	349,414,687	32,182	177,464,376	31,865	754,825,520
Total OPA Contracted Province-Wide CDM Programs	**281,051**	**833,647,614**	**217,063**	**539,927,035**	**110,290**	**2,169,045,114**

#	Initiative	Total Adjustments to Net Savings		Gross Savings		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	51%	51%	6,593	46,057,318	3,237	23,051,053	3,124	92,084,366
2	Appliance Exchange	51%	51%	611	873,531	314	448,204	114	1,581,664
3	HVAC Incentives	60%	60%	44,912	99,183,504	27,039	59,298,742	27,039	237,194,969
4	Conservation Instant Coupon Booklet	114%	111%	1,155	18,710,962	1,307	20,587,781	1,307	82,351,123
5	Bi-Annual Retailer Event	112%	110%	1,501	26,895,018	1,672	29,244,710	1,672	116,978,841
6	Retailer Co-op	68%	68%	0	3,872	0	2,620	0	10,481
7	Residential Demand Response	n/a	n/a	10,962	21,457	10,962	21,457	0	21,457
8	Residential New Construction	41%	41%	0	1,813	0	743	0	2,973
Business Program									
9	Efficiency: Equipment Replacement	74%	89%	40,566	222,463,716	29,076	164,854,612	28,537	657,312,974
10	Direct Installed Lighting	161%	83%	22,191	65,883,282	23,763	61,175,205	16,523	221,910,236
11	Existing Building Commissioning Incentive	n/a	n/a						
12	New Construction and Major Renovation Incentive	50%	50%	216	688,173	108	344,086	108	1,376,346
13	Energy Audit	n/a	n/a						
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	84	162	84	162	0	162
15	Demand Response 3 (part of the Industrial program schedule)	n/a	n/a	15,533	415,353	15,533	415,353	0	415,353
Industrial Program									
16	Process & System Upgrades	n/a	n/a	0	0	0	0	0	0
17	Monitoring & Targeting	n/a	n/a	0	0	0	0	0	0
18	Energy Manager	n/a	n/a	0	0	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	74%	89%	Split between Business and Industrial Programs to be provided with final results					
20	Demand Response 3	n/a	n/a	71,783	2,978,648	71,783	2,978,648	0	2,978,648
Home Assistance Program									
21	Home Assistance Program	70%	70%	4	56,119	2	39,283		
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	44%	45%	32,918	170,329,201	14,308	76,285,293	14,308	352,441,795
23	High Performance New Construction	49%	49%	10,173	53,412,129	5,086	26,706,065	5,086	104,492,604
24	Toronto Comprehensive	59%	60%	19,595	118,783,632	11,289	69,955,286	11,289	279,821,143
25	Multifamily Energy Efficiency Rebates	66%	66%	1,798	6,876,658	1,180	4,504,801	1,180	18,019,205
26	Data Centre Incentive Program	100%	100%	2	12,614	2	12,614	2	50,456
27	EnWin Green Suites	70%	70%	453	453	317	317	0	317

** Includes BOTH adjustments due to Realization Rate and Net-to-Gross Ratio (weighted by peak demand or energy savings); See "Methodology" tab for more information*

*** Please see "Methodology" tab for information regarding determining LDC-specific savings*

Assumes demand response resources have a persistence of 1 year

Summary - Provincial Progress

2011 Results: Province-Wide Results

Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	220.4	121.7	121.0	113.6
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				113.6
2014 Annual CDM Capacity Target				1,330
Verified Peak Demand Savings Target Achieved - 2011 (%):				8.54%

Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	556.0	552.4	550.4	529.7	2,189
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					2,189
2011-2014 Cumulative CDM Energy Target:					6,000
Verified Portion of Energy Target Achieved - 2011 (%):					36.48%

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
Gross Savings = Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year and quarter that appliance has been picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	Results allocated based on average of 2008 & 2009 residential throughput when postal code information not provided by customer	Savings are considered to begin in the year and quarter that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year and quarter that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Data is provided to the OPA with the associated program year. Savings are considered to begin that specified program year. Currently, coupon redemption date is unavailable.	
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the quarter and year in which the event occurs.	

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
6	Retailer Co-op	Results allocated based on average of 2008 & 2009 residential throughput when postal code information not provided by customer; Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.	Savings are considered to begin in the year and quarter of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year and quarter the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. However all devices installed in 2011 and/or customers that have signed a peaksaver PLUS™ participant agreement as of December 31st are included in the ex ante savings estimate.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year and quarter of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Business Program

Gross Savings = Reported Savings * Realization Rate
Net Savings = Gross Savings * Net-to-Gross Ratio
All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year and quarter of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year and quarter of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year and quarter of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year and quarter the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement. However all devices installed in 2011 and/or customers that have signed a peaksaver PLUS™ participant agreement as of December 31st are included in the ex ante savings estimate.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year and quarter in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
Gross Savings = Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year and quarter in which the project was completed by the energy manager. If no date is specified the savings will begin the year and quarter of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year and quarter of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year and quarter in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
Gross Savings = Activity * Per Unit Assumption **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year and quarter in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011				
Gross Savings = Reported Savings * Realization Rate **Net Savings =** Gross Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		

METHODOLOGY

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year and quarter in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Ontario Power Authority
Conservation & Demand Management Status Report

Q1 2012 Preliminary Results Update to March 31, 2012

Canadian Niagara Power Inc.

Unverified LDC Tier 1 Progress Performance at a Glance

Table 1 shows unverified progress to target using two scenarios:

Scenario 1: Aggregation of LDC achievement in energy efficiency (EE)and demand response (DR) initiatives using the current DR reporting policy of 1 year persistence. This scenario is used on pages 4 - 7.

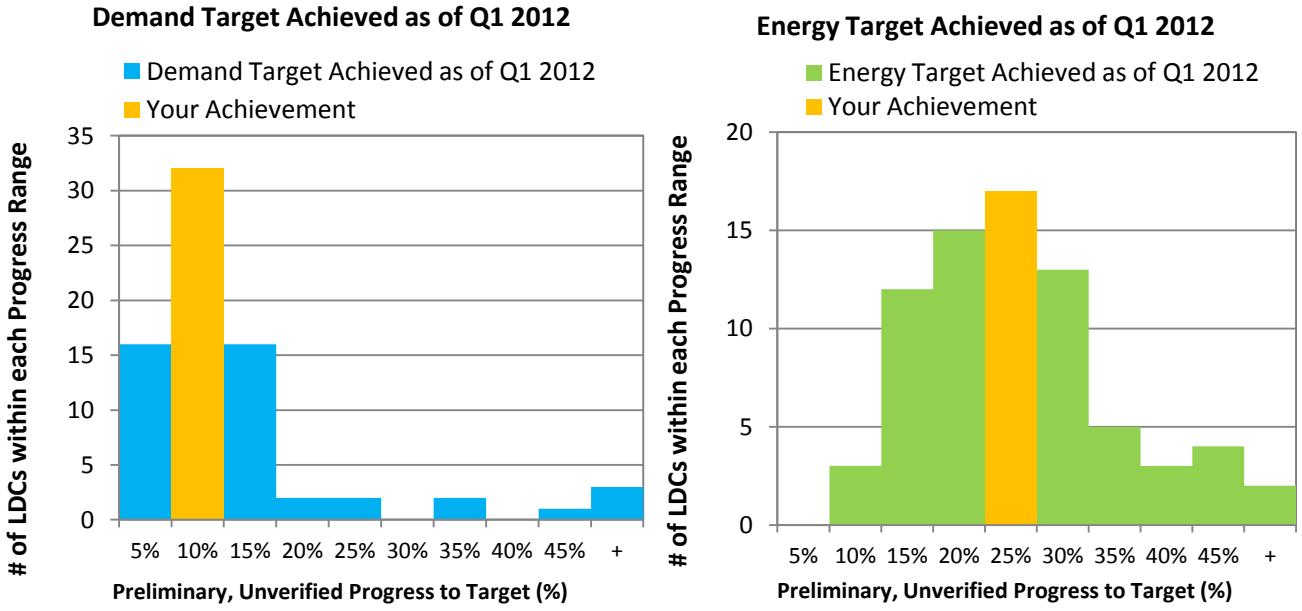
Scenario 2: Aggregation of LDC acheivement in EE and DR initiatives using alternate assumption that DR customers contribute to the program until 2014, including participant acheivement to date. Scenario 2 is used on this page only.

Table 1: Unverified Progress to Targets

Unverified Progress to Targets	Scenario 1	Scenario 2	
	% of Target Achieved	% of Target Achieved	Rank (of 77)
Net Annual Peak Demand Savings in 2014	**4.6%**	**7.7%**	46
2011-2014 Net Cumulative Energy Savings	**24.8%**	**24.6%**	31

Figures 1 & 2 shows a histogram with all LDCs' unverified performance towards their OEB targets and where your LDC performance is in relation to the LDC community. The golden lines show your progress towards peak demand and energy targets, respectively.

Figures 1 & 2: LDC Position in Relation to Entire LDC Community



For Example: there are 3 LDCs that have achieved between 5 and 10% of their OEB cumulative energy target using scenario 2.

Message from the Vice President

Q1 2012 was an exciting quarter for the OPA and LDCs. Customer participation in the saveONenergy programs continues to gain momentum. 25 LDCs have achieved over 25% of their cumulative energy target in Q1 2012 compared to only 9 in Q4 2011! To further build the capability of the LDC community and innovative program delivery, please share your success stories so others can learn and build from your best practices.

Through the effective collaboration continuing into Q1 2012 the OPA and LDCs have begun to incorporate additional tools and greater flexibility to deliver more customer centric programs. We anticipate the resulting improvements will further drive customer participation - encouraging a culture of conservation across the province. We look forward to continuing to work with the LDCs to bring these customized program ideas forward.

Congratulations on another successful quarter. We invite you to contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions or potential opportunities regarding this report.

Sincerely,

- Andrew Pride
Vice President, Conservation
Ontario Power Authority

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not incl. Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts).
- Unverified quarterly results discounted using forecasted net-to-gross ratios. Once full Evaluation, Measurement & Verification (EM&V) occurs in the following year, results will be identified as final (verified).
- Program activity data (i.e. projects completed, appliances picked up) completed on or before March 31, 2011 and received and entered into the OPA processing systems as per the dates specified in Table 6.
- Updates to the previous quarter's participation due to more data availability.
- *Assumption of 1 year persistance used to inform the remainder of this report

Future reports will contain:

- More data for the Home Assistance Program
- Preliminary results for **peaksaver PLUS™** representing participants that have signed a Participant Agreement will appear

New this quarter based on LDC feedback:

- Demand response is now reported in both the "YTD Incremental" and "YTD Incremental (2012-to-Date)" columns. These values represent the total demand response under contract in your LDC territory as of the end of the current reporting period.
- Assumptions have been updated to reflect findings from 2010 Evaluations and consultation with the Consumer, Business, and Industrial Work Groups. A document containing the net-to-gross ratio assumptions that will be used in 2012 preliminary, unverified reporting is available on the iCON Portal under "Other Program Materials." The item is called: "Reporting tools." OPA will continue to populate this folder with information to help LDCs understand reporting assumptions and policies.

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured through Tier 1 programs to date.

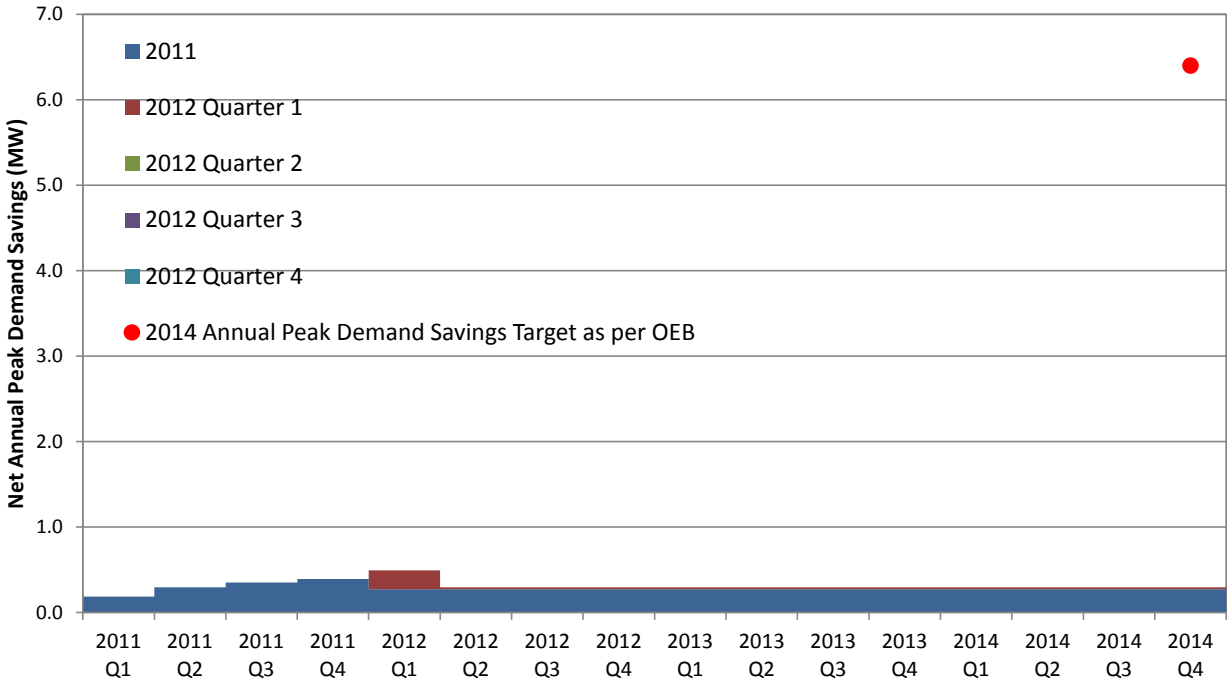
Table 2 presents preliminary net peak demand savings results from 2011 to date listed by implementation period. This table also presents the net annual peak demand savings that are expected to persist through to 2014 from program activity completed to date. Please note that Demand Response 1 and 3 have a persistence of 1 year in the table and figure below.

Table 2: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual			
		2011	2012	2013	2014
1	2011 - Reported	0.39	0.27	0.27	0.27
2	2012 - Reported - Quarter 1		0.22	0.02	0.02
3	2012 - Reported - Quarter 2				
4	2012 - Reported - Quarter 3				
5	2012 - Reported - Quarter 4				
6	2013				
7	2014				
Annual Reported (Unverified)		0.39	0.49		
Annual Final (Verified)		n/a	n/a		
Unverified Net Annual Peak Demand Savings in 2014:					**0.29**
2014 Annual Peak Demand Savings Target as per OEB:					**6.40**
Unverified 2014 Peak Demand Savings Target Achieved (%):					**4.6%**

Figure 3 presents a visual summary of the information contained in Table 2.

Figure 3: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured through Tier 1 programs to date.

Table 3 presents preliminary net annual energy savings results from 2011 to date by implementation period. This table also presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date.

Table 3: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual				Cumulative
		2011	2012	2013	2014	2011-2014
1	2011 - Reported	1.50	1.49	1.49	1.49	5.98
2	2012 - Reported - Quarter 1		0.08	0.08	0.08	0.23
3	2012 - Reported - Quarter 2					
4	2012 - Reported - Quarter 3					
5	2012 - Reported - Quarter 4					
6	2013					
7	2014					
Annual Reported (Unverified)		1.50	1.57			
Annual Final (Verified)		n/a	n/a			
Unverified Net Cumulative Energy Savings 2011-2014:						**6.21**
2011-2014 Cumulative Energy Savings Target as per OEB:						**25.08**
Unverified 2011-2014 Cumulative Energy Target Achieved (%):						**24.8%**

Figure 4 presents a visual summary of the information contained in Table 3.

Figure 4: Net Cumulative Energy Savings (GWh)

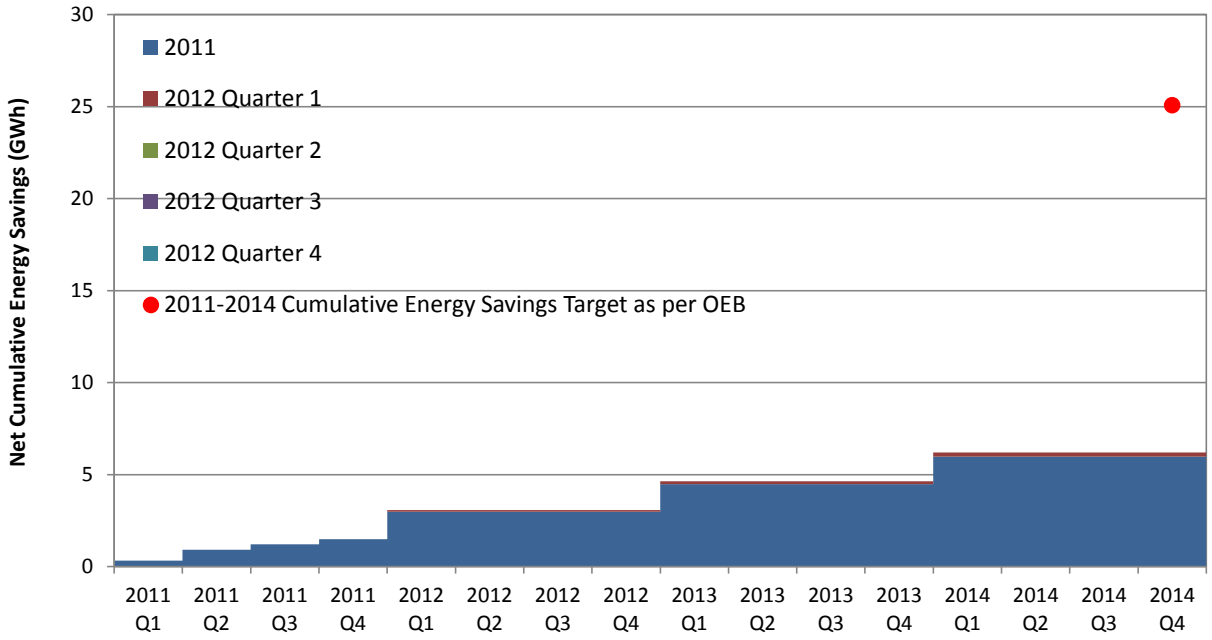


Table 4: **Canadian Niagara Power Inc.** Initiative and Program Level Savings

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2012-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	22	250	2	2	23	12,663	12,663	557,807
2	Appliance Exchange	Appliances	0	120	0	0	5	0	0	34,162
3	HVAC Incentives	Equipment	42	290	9	9	61	13,994	13,994	359,771
4	Conservation Instant Coupon Booklet	Coupons	0	919	0	0	2	0	0	230,544
5	Bi-Annual Retailer Event	Coupons	0	2,032	0	0	3	0	0	401,584
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0
7	***peaksaver*** ® extension	Devices	0	0	0	0	0	0	0	0
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	0	0	0.00	0.00	0	0	0	0
Consumer Program Total					**11**	**11**	**94**	**26,657**	**26,657**	**1,583,868**
Business Program										
11	Equipment Replacement Incentive	Projects	2	13	1	1	8	4,760	4,760	276,277
12	Direct Installed Lighting	Projects	0	0	0	0	0	0	0	0
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	***peaksaver*** ® extension	Devices	0	0	0	0	0	0	0	0
17	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
18	Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total					**1**	**1**	**8**	**4,760**	**4,760**	**276,277**
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	0	0	0	0	0	0	0	0
23	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
24	Demand Response 3	Facilities	3	3	200	200	0	2,080	2,080	3,328
Industrial Program Total					**200**	**200**	**0**	**2,080**	**2,080**	**3,328**
Home Assistance Program										
25	Home Assistance Program	Units	0	0	0	0	0	0	0	0
Home Assistance Program Total					**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	14	0	0	152	0	0	3,536,081
26	High Performance New Construction	Projects	0	1	9	9	41	44,488	44,488	808,086
27	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
28	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total					**9**	**9**	**194**	**44,488**	**44,488**	**4,344,167**
OPA-Contracted Province-Wide Portfolio Total					**220**	**220**	**295**	**77,986**	**77,986**	**6,207,640**
Unverified Savings Target Achieved:							**4.6%**			**24.8%**

Table 5: Province-Wide Initiative and Program Level Savings

All results are NET and presented at the end-user level

#	Initiative	Activity			Net Peak Demand Savings (kW)			Net Energy Savings (kWh)		
		Unit	Incremental (Current Quarter)	Program-to-Date (2011-to-Date):	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified annual savings in 2014	Incremental (Current Quarter)	YTD Incremental (2011-to-Date)	Program-to-Date: unverified cumulative savings in 2014
Consumer Program										
1	Appliance Retirement	Appliances	7,188	63,258	662	662	5,618	4,073,618	4,073,618	138,629,181
2	Appliance Exchange	Appliances	0	4,152	0	0	185	0	0	1,179,214
3	HVAC Incentives	Equipment	12,353	102,735	2,702	2,702	21,342	4,261,812	4,261,812	127,297,206
4	Conservation Instant Coupon Booklet	Coupons	0	201,500	0	0	388	0	0	49,225,347
5	Bi-Annual Retailer Event	Coupons	0	397,676	0	0	637	0	0	78,587,230
6	Retailer Co-op	Items	0	152	0	0	0	0	0	98
7	***peaksaver*®** extension	Devices	0	17,825	0	0	9,982	0	0	1,568,600
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	1	6	0.01	0.01	0.05	123	123	2,597
Consumer Program Total					**3,364**	**3,364**	**38,151**	**8,335,553**	**8,335,553**	**396,489,473**
Business Program										
11	Equipment Replacement Incentive	Projects	426	3,644	2,071	2,071	12,095	7,999,750	7,999,750	233,373,113
12	Direct Installed Lighting	Projects	3,283	19,053	1,701	1,701	7,794	12,503,959	12,503,959	266,707,290
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	381	0	0	20	0	0	319,108
16	***peaksaver*®** extension	Devices	0	112	0	0	72	0	0	2,903
17	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
18	Demand Response 3	Facilities	149	145	17,253	17,253	0	536,415	536,415	1,070,310
Business Program Total					**21,024**	**21,024**	**19,981**	**21,040,124**	**21,040,124**	**501,472,725**
Industrial Program										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	82	785	733	733	4,832	3,508,356	3,508,356	91,723,489
23	Demand Response 1	Facilities	0	0	0	0	0	0	0	0
24	Demand Response 3	Facilities	132	125	53,447	53,447	0	555,851	555,851	1,115,587
Industrial Program Total					**54,180**	**54,180**	**4,832**	**4,064,207**	**4,064,207**	**92,839,076**
Home Assistance Program										
25	Home Assistance Program	Units	166	671	0	0	1	39,667	39,667	258,809
Home Assistance Program Total					**0**	**0**	**1**	**39,667**	**39,667**	**258,809**
Pre-2011 Programs completed in 2011										
25	Electricity Retrofit Incentive Program	Projects	0	953	0	0	9,962	0	0	235,219,415
26	High Performance New Construction	Projects	57	317	2,108	2,108	10,100	10,827,160	10,827,160	196,665,067
27	Toronto Comprehensive	Projects	0	735	0	0	12,651	0	0	300,325,644
28	Multifamily Energy Efficiency Rebates	Projects	0	110	0	0	1,798	0	0	27,506,630
Pre-2011 Programs completed in 2011 Total					**2,108**	**2,108**	**34,510**	**10,827,160**	**10,827,160**	**759,716,757**
OPA-Contracted Province-Wide Portfolio Total					**80,676**	**80,676**	**97,475**	**44,306,711**	**44,306,711**	**1,750,776,840**
Unverified Savings Target Achieved:							**7.3%**			**29.2%**

Table 6: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Initiative	Savings 'start' Date	Data Available	As Of:	Additional Data
Consumer Program				
Conservation Instant Coupon Booklet	Invoice date from coupon clearinghouse	Once data is submitted to the OPA by retailers	Apr. 13, 2012	High
Bi-Annual Retailer Event				
Appliance exchange initiative	Event date		Apr. 19, 2012	Low
Retailer co-op activities	Will vary by specific project	Varies by specific project	Apr. 15, 2012	Low
Appliance Retirement	Pick-up date	When database is queried	Apr. 26, 2012	Moderate
HVAC Incentives	Installation date	Customers submit rebate and invoices are processed	Apr. 16, 2012	Moderate
peaksaver extension	Device installation date	Project Completion Report uploaded to the iCON Portal	Apr. 23, 2012	Moderate
New construction	Project completion	Preliminary Billing Report issued to LDC	Apr. 19, 2012	Low
Business (Commercial & Institutional) Program				
Direct Installed Lighting	Project Completion Date	Work-order: invoiced, approved and paid to LDC	Feb. 29, 2012	High
Equipment Replacement Incentive		"Approved for Payment by LDC" or "Released for Payment" status on iCON	Apr. 18, 2012	High
Process & Systems Upgrades			Apr. 20, 2012	Low
Building Commissioning		Upon payment to LDC	Apr. 23, 2012	Moderate
New Construction		Upon payment to LDC	Apr. 23, 2013	Moderate
peaksaver extension	Device installation Date	Upon payment to LDC	Apr. 23, 2012	Moderate
Demand Response (DR1, DR3)	Facility is available under contract	Facility under contract with aggregator	Apr. 11, 2012	Low
Industrial Program				
Equipment Replacement Incentive	Project Completion Date	"Approved for Payment by LDC" or "Released for Payment" status on iCON	Apr. 18, 2012	High
Process & System Upgrades	In Service Date		Apr. 20, 2012	Low
Monitoring & Targeting	2nd year Report	Report submitted	Apr. 20, 2012	Low
Demand Response (DR1, DR3)	Facility is available under contract	Facility available under contract	Apr. 11, 2012	Low
Energy Manager	Quarterly Report Date	Report submitted quarterly	Apr. 20, 2012	Low
Home Assistance Program				
Home Assistance Program	Project Completion Date	Data sent to OPA by LDC	Apr. 19, 2012	High
Pre-2011 Projects Completed in 2011				
High Performance New Construction	Project Completion Date	From delivery agent, quarterly (results currently allocated)	Apr. 20, 2012	High
Electricity Retrofit Incentive Program		Upon payment to LDC	Apr. 15, 2012	High
Multifamily Energy Efficiency Rebates			Nov. 2011	Low
Toronto Comprehensive			Apr. 15, 2012	High

For Example: Preliminary results for Retrofit are reported in this quarter if a project is completed on or before Dec. 31, 2011 and had the iCON status "Approved for payment by LDC" or "Released for Payment" as of Jan. 18, 2012. There is a high probability that there are more results coming in for this initiative.

Reporting Methodology (Quarterly, Unverified results)

Over the last quarter, LDC and OPA members of the Reporting Work Group have been working on communicating reporting policies and procedures to the LDC community. There are now several resources for your use including: Reporting Policy & FAQ Document, LDC Consumer Program Tracking Tool (both of which available on the iCON Portal in "Other Program Materials" in the "Reporting Tools" folder), and several webinars available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php

Notes:

- Table 6 is intended to assist the LDC in reconciling internal data sources with the data contained in this report by communicating:
  1 The date in which savings are considered to 'start';
  2 At what point the data becomes available to the OPA;
  3 The date in which the data was collected for reporting purposes; and
  4 The expectated probability and magnitude of updates to the data as more information becomes available.
- OPA will query iCON CRM for Retrofit data on the Wednesday, 2 weeks following the end of the calendar quarter. If you would like to have the ability to align the projects included in quarterly reports with your records, please run a query on the same day.

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Final Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported Savings: savings achieved that are based on reported activity and forecasted savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

3. Load Forecast and Operating Revenue

3.4
Is the test year forecast of other revenues appropriate?

(OEB)

Load Forecast and Operating Revenue

Issue 3.4
Is the test year forecast of other revenues appropriate?

22. Ref: E3/T3/S1 p. 1 - 2 – Revenues and Costs from Merchandise, Jobbing, Etc. – FE/EOP

In the table on page 1 CNPI shows a decline of $1,709,308 (74.35%) in the 2012 bridge year and $1,742,185 (75.78%) in the 2013 test year over 2011 actual in account 4325, Revenues from Merchandise, Jobbing, Etc. Similarly, account 4330 , Cost and Expenses of Merchandising, Jobbing, Etc. declined by $1,849,520 (87.71%) in 2012 and $2,051,110 (93.72%) over 2011 actual.

On page 2 CNPI states that "*Revenues generated from third party job orders includes revenues associated with the IT Service Agreements with each of CNPI's associated companies that use CNPI's SAP…. Revenues and costs in accounts 4325 and 430, respectively, generally offset and thus, are not forecasted for 2012 and 2013. The net revenue in prior years primarily relates to IT services provided to associated companies."*

a) Please provide the table showing all revenues and costs, including IT service revenues and costs.
b) Please show the net revenues related to CNPI's associated companies that use CNPI's SAP.
c) Please explain the increase in both revenues (276%) and costs (295%) in 2011 from 2009 actual.

RESPONSE:

a)

Other Distribution Revenues - FE and EOP
Accounts 4325 and 4330

Account 4325

Description	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test 2013
EBT Enrollment Services	25,662				
Westario - Misc Billable	36,599	39,703	11,917		
Westario Smart Meters	41,791	9,387	118,340		
Grimsby Smart Meter		3,557	54,601		
Grimsby Backoffice ERP Implementation	87,500				
Algoma Power Inc.-Billable	249,122	1,452,055	1,938,569	166,687	
IT Services for Westario	80,128	121,416	121,416	262,882	347,364
IT SUPPORT - GPI	25,922	42,000	42,000	160,000	209,328
FE - REPLACE POLE LINE FOR BELL CANADA	41,277	(41,277)			
Miscellaneous	22,567	7,840	12,034		
Total	610,568	1,634,681	2,298,877	589,569	556,692

Account 4330

Description	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test 2013
EBT Enrollment Services	(25,662)				
Westario - Misc Billable	(25,158)	(39,703)	(11,264)		
Westario Smart Meters	(34,769)	(7,792)	(116,834)		
Grimsby Smart Meter		(3,557)	(54,601)		
Grimsby Backoffice ERP Implementation	(87,500)				
Algoma Power Inc.-Billable	(249,122)	(1,452,055)	(1,938,569)	(166,687)	
IT Services for Westario	(45,337)	(62,185)	(38,077)	(59,850)	(82,650)
IT SUPPORT - GPI	(28,678)	(30,376)	(10,955)	(39,900)	(54,150)
FE - REPLACE POLE LINE FOR BELL CANADA	(41,277)	41,277			
Miscellaneous	(16,203)	(8,931)	(18,211)	(2,553)	(600)
Total	(553,707)	(1,563,322)	(2,188,510)	(268,990)	(137,400)
Net Total	56,861	71,359	110,367	320,579	419,292

b)

Description	Actual 2009	Actual 2010	Actual 2011	Bridge 2012	Test 2013
Net Revenue from Associated Companies for SAP Services	32,035	70,855	114,385	323,132	419,892

c) The increase in both revenues and costs from 2009 to 2011 is due to Algoma Power Inc. As a result of having different accounting systems all intercompany charges and allocations had to be processed through the billing system. In 2012 Algoma Power is using the SAP system and this process is no longer required.

(OEB)

Load Forecast and Operating Revenue

Issue 3.4
Is the test year forecast of other revenues appropriate?

23. Ref: E3/T3/S1 p. 1-3 – Gain/Loss on Disposition of utility property.

On page 3 CNPI stated that it did not forecast any gains or losses on disposition of utility or other property. Please explain why.

RESPONSE:

CNPI is not forecasting any gains or losses on the disposal of property during the test year due to the unpredictable nature of these transactions. Forecasting is further challenged with the determination if any planned disposals (e.g. vehicles) would be at a gain or loss. Consistent with past rate applications, CNPI has not forecasted any gains or losses for the test year.

Consistent with the IFRS Report Addendum (20110613), CNPI is also not requesting the approval of a variance account relating to the gains and losses on the early retirement of in-service assets. CNPI does not believe it can "demonstrate the probability of significant ongoing volatility" as required by the report.

(OEB)

Load Forecast and Operating Revenue

Issue 3.4
Is the test year forecast of other revenues appropriate?

24. Ref: E3/T3/S1 p.3 – Cost Expenses of Non-Utility Operations

CNPI stated that "Revenues and costs for CDM offset each other. CNPI did not forecast any revenues or cost for the 2012 bridge and the 2013 test year. Please explain why.

RESPONSE:

CNPI, currently, only participates in the OPA-Contracted Province-Wide CDM Programs and did not provide a test year forecast as these revenue and expenses are outside the distribution rates framework. Funding is provided by the OPA. Revenues and expenses from these CDM activities are not regulated by the Board and are therefore non-regulated revenues and expenses.

(EP)

3. Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenues appropriate?

38. Ref: Exhibit 3, Tab 3, Schedule 1

a) Please explain the spike in Account 4220 Other Electric Revenues in 2011.

b) Please explain the increase in 2012 and the decrease in 2013 forecast for Account 4235 Miscellaneous Service Revenues.

c) Please confirm that the figures shown in Account 4360 Loss on Disposition of Utility and Other Property in 2009 through 2011 were gains and not losses.

d) Please provide a table in the same level of detail as that shown on page 1 that shows the most recent year-to-date figures for 2012 that are currently available, along with the revenues for the corresponding period in 2011.

RESPONSE:

a) The spike in OEB Account 4220 in 2011 is due to $8,613 received as a result of theft of power.

b) The increase in 2012 was based on the historical data from previous years. In 2013, the company expects lower revenues from disconnections fees due to the expanded low-income payment rules.

c) The figures shown in OEB account 4360 in 2009 through 2011 are gains not losses.

d)

Other Operating Revenue - FE and EOP

OEB Account	Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Actual June 30, 2011	Actual June 30, 2012
4080	Distribution Services Revenue (SSS Revenue)	50,000	48,734	50,531	52,330	53,284	53,443	26,165	26,642
4082	Retail Services Revenues	36,550	31,708	32,648	24,630	23,500	23,500	11,340	10,057
4084	Service Transaction Requests (STR) Revenues	1,700	772	1,619	946	900	900	376	281
4210	Rent from Electric Property	231,000	229,901	229,399	229,399	230,004	231,100	81,954	115,401
4220	Other Electric Revenues	4,000	3,944	5,670	14,725	6,003	6,009	1,556	14,918
4225	Late Payment Charges	234,000	246,645	248,914	259,554	259,341	260,323	137,664	109,457
4235	Miscellaneous Service Revenues	119,000	114,060	119,149	106,591	117,982	107,325	49,596	45,935
4325	Revenues from Merchandise, Jobbing, Etc.	4,088	610,568	1,634,681	2,298,877	589,569	556,692	731,394	320,806
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	(4,457)	(553,707)	(1,563,322)	(2,188,510)	(268,990)	(137,400)	(679,134)	(200,113)
4360	Loss on Disposition of Utility and Other Property	-	52,967	39,553	25,075	-	-	12,583	17,304
4375	Revenues from Non-Utility Operations	-	631,953	257,540	320,625	-	-	188,052	246,264
4380	Expenses of Non-Utility Operations	-	(631,940)	(257,489)	(320,625)	-	-	(188,052)	(246,264)
4398	Foreign Exchange Gains and Losses, Including Amortization	-	(4,279)	(41,838)	(13,443)	-	-	(5,818)	(1,902)
4405	Interest and Dividend Income	35,000	9,632	12,618	34,865	30,000	30,000	12,088	20,016
	Other Operating Revenue	**710,881**	**790,958**	**769,672**	**845,040**	**1,041,593**	**1,131,892**	**379,764**	**478,802**

(EP)

3. Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenues appropriate?

39. Ref: Exhibit 3, Tab 4, Schedule 1

a) Please explain the increase in 2012 and the decrease in 2013 forecast for Account 4235 Miscellaneous Service Revenues.

b) Please explain why there are no revenues and costs forecast for 2012 and 2013 in accounts 4325 and 4330.

c) Please provide a table in the same level of detail as that shown on page 1 that shows the most recent year-to-date figures for 2012 that are currently available, along with the revenues for the corresponding period in 2011.

RESPONSE:

a) The increase in 2012 is based on the historical data from previous years. In 2013, the company expects lower revenues from disconnections fees due to the expanded low-income payment rules. In addition move-in fees are forecasted slightly lower in 2013 based on 2011 Actuals.

b) No revenues and costs are forecast for 2012 and 2013 in accounts 4325 and 4330 due to the fact that over time the revenues and costs normally net to zero. In 2009 there was one-time revenue received of $20,684 without which the net total would have been $2,189. In 2010, revenue of $8,000 was received that related to costs in a prior period, without which the net total would have been $4,006. An accurate and reliable forecast of small one-time costs cannot be made and therefore the forecast is based on the revenues and costs netting to zero.

c)

Other Operating Revenue

OEB Account	Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Actual June 30, 2011	Actual June 30, 2012
4080	Distribution Services Revenue (SSS Revenue)	22,500	22,361	25,833	24,913	25,977	26,119	12,457	12,988
4082	Retail Services Revenues	22,500	15,390	15,603	10,583	10,000	10,000	4,850	4,581
4084	Service Transaction Requests (STR) Revenues	1,000	371	776	469	500	500	223	232
4210	Rent from Electric Property	86,000	86,078	85,912	85,912	86,006	86,000	27,937	43,093
4220	Other Electric Revenues	2,000	4,721	3,757	2,470	2,509	3,864	2,164	(1,661)
4225	Late Payment Charges	100,000	89,157	103,548	99,893	97,355	100,779	54,604	47,769
4235	Miscellaneous Service Revenues	52,000	54,605	50,176	44,145	52,391	44,030	21,585	22,025
4325	Revenues from Merchandise, Jobbing, Etc.	-	72,433	53,580	39,501	-	-	16,876	13,693
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	(49,557)	(41,574)	(30,456)	-	-	(8,137)	(11,613)
4360	Loss on Disposition of Utility and Other Property	-	(1,500)	-	191	(15,968)	-	-	(15,552)
	Other Operating Revenue	**286,000**	**294,060**	**297,611**	**277,621**	**258,770**	**271,292**	**132,559**	**115,555**

(SEC)

3. Load Forecast and Operating Revenue
3.4 Is the test year forecast of other revenues appropriate?

7. [Ex.3/3/3/p.1]
Please provide the 2012 year-to-date 'other operation revenues' by USoA account for CNPI - Fort Erie/EOP.

RESPONSE:

Please see the response to Energy Probe interrogatory 3.4 #1d, (CNPI #38d).

(SEC)

3. Load Forecast and Operating Revenue
3.4 Is the test year forecast of other revenues appropriate?

8. [Ex.3/4/2/p.1]
Please provide the 2012 year-to-date 'other operation revenues' by USoA account for CNPI-Port Colborne.

RESPONSE:

Please see response to Energy Probe interrogatory 3.4 #2c, (CNPI #39c).

(SEC)

3. Load Forecast and Operating Revenue
3.4 Is the test year forecast of other revenues appropriate?

9.[Ex.3/3/3, Ex.3/3/4]
With respect to micro-FIT revenue,

a) Please provide the number connections in CNPI - Fort Erie/EOP and CNPI-Port Colborne for year-end 2011 and year-to-date for 2012.
b) Please provide the actual revenue for connections in CNPI - Fort Erie/EOP and CNPI-Port Colborne for year-end 2011 and year-to-date for 2012.
c) Please provide the estimated number of connections and revenue for the Test Year.

RESPONSE:

a) For year-end 2011, the number of Micro-FIT connections for CNPI – FE/EOP was 17 and CNPI – PC was 9. As at June 30, 2012, the number of Micro-FIT connections for CNPI – FE/EOP was 29 and CNPI – PC was 12.

b) For year-end 2011, the actual revenue (based on the $5.25 monthly service charge) for Micro-FIT connections for CNPI – FE/EOP was $479 and CNPI – PC was $259. As at June 30, 2012, the actual year-to-date revenue for Micro-FIT connections for CNPI – FE/EOP was $673 and CNPI – PC was $330.

c) For the 2013 Test Year, the estimated average number of Micro-FIT connections for CNPI – FE/EOP was 19 and CNPI – PC was 8. The 2013 Test Year budgeted revenue (based on the $5.25 monthly service charge) for Micro-FIT connections for CNPI – FE/EOP is $1,197 and for CNPI – PC was $473.

(VECC)

Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenue appropriate?

10. Reference: Exhibit 3, Tab 3, Schedule 3, page 1
Exhibit 3, Tab 4, Schedule 1, page 1

a) How many micro-Fit customers does CNPI have in each of its service areas as of December 31, 2011?

b) How many micro-Fit customers does CNPI expect to have in 2013 (annual average)?

c) Where is the revenue from micro-Fit service charges reflected in the Other Distribution Revenue Offset tables?

d) How much revenue is CNPI forecasting to receive from micro-Fit customers in 2013?

RESPONSE:

a) Please refer to response provided by CNPI in School Energy Coalition Interrogatory Question 9, Part A.

b) Please refer to response provided by CNPI in School Energy Coalition Interrogatory Question 9, Part C.

c) The revenue from Micro-FIT service charges is included in OEB 4080 Distribution Revenue.

d) Please refer to response provided by CNPI in School Energy Coalition Interrogatory Question 9, Part C.

(VECC)

Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenue appropriate?

11. Reference: Exhibit 3, Tab 3, Schedule 3, pages 1-2

a) Please explain the increase in EOP/FE Other Electric Revenues in 2011 ($14,725) and why the increase is not expected to continue in 2012 and 2013.

b) Please explain the EOP/FE Miscellaneous Service Revenues declined in 2011 and why, after forecasting an increase in 2012, they are forecast to decline again in 2013.

RESPONSE:

a) Please see response to Energy Probe 3.4 #1a.

b) 2011 Miscellaneous Service Revenues declined due to a lower number of disconnection fees in that year. The increase in 2012 was projected based on historical data, averaged from previous years. In 2013, the Company continues to expect lower revenues from disconnections fees due to the expanded low-income payment rule (i.e., arrears management program and refunding security deposits), and therefore forecasted revenues which aligned with 2011 Actuals.

(VECC)

Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenue appropriate?

12. Reference: Exhibit 3, Tab 3, Schedule 2, pages 1-2

a) How is the return on invested capital that is included in the IT Services Fees determined?

b) The last paragraph on page 2 makes reference to increases in revenues for Account #4325 in 2012 and 2013. However, Appendix 2-C shows revenues for this account declining significantly in 2012 and 2013 relative to previous years. Please reconcile.

RESPONSE:

a) The return on invested capital is included in the *Asset Utilization* fee referred to in Exhibit 3, Tab 3, Schedule 2, page 1. It is determined by including a return on CNPI's invested capital based on the weighted average cost of CNPI's capital applied to the current net book value of IT assets.

b) Please see response to OEB question #22.

(VECC)

Load Forecast and Operating Revenue

3.4 Is the test year forecast of other revenue appropriate?

13. Reference: Exhibit 3, Tab 4, Schedule 2, pages 1-2

a) Please explain why PC Miscellaneous Revenues declined in 2011 and why, after forecasting an increase in 2012, they are forecast to decline again for 2013.

RESPONSE:

a) 2011 Miscellaneous Service Revenues declined primarily due to a lower number of disconnection fees in that year. The increase in 2012 was projected based on historical data, averaged from previous years. In 2013, the company continues to expect lower revenues from disconnections fees due to the expanded low-income payment rules. The forecasted revenues for 2013 are aligned with 2011 Actuals.

Canadian Niagara Power Inc.

EB-2012-0112

Response to Operating Costs Interrogatories

4. Operating Costs

4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

25. Ref: E1/T2/S1/p.1 and E4 – Operating Expenses

In the first reference CNPI stated:

> *Changes to the revenue requirement and rate base as a result of the change in accounting are included in Exhibit 11. Detailed schedules (e.g. revenue requirement workform, fixed asset continuity, revenue deficiency, etc.) have also been reproduced in Exhibit 11.*
> *The schedules elsewhere in this document, including this Application Overview, are prepared using existing the accounting policy / estimate with exception of cost allocation and rate design (i.e. cost allocation and rate design are prepared under MIFRS).*

Please reproduce all tables and schedules in Exhibit 4 showing the charges to CNPI's capitalization policy as a separate column.

RESPONSE:

The tables and schedules in Exhibit 4 are attached except for the following which had no changes due to MIFRS:

Appendix 2-H – Regulatory Cost Schedule

Appendix 2-K – Compensation Analysis

Appendix 2-L – Shared Services/Corporate Cost Allocation

CCA Schedules

Appendix 2-M
Depreciation and Amortization Expense
2013
FE and EOP

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Changes due to MIFRS	MIFRS Depreciation Expense
1608	Franchises & Consents	156,053	-	156,053	-	-	156,053	40.00	2.50%	3,901		3,901
1805	Land	189,861	-	189,861	-	-	189,861					-
1806	Land Rights	215,966	49,918	166,048	26,052	(13,026)	179,074	40.00	2.50%	4,477		4,477
1808	Buildings	3,758,190	0	3,758,190	25,042	(12,520)	3,770,712	50.00	2.00%	75,414	(50)	75,364
1820	Substation Equipment	6,576,742	100,671	6,476,071	468,736	(234,368)	6,710,438	33.33	3.00%	201,333	(66,087)	135,246
1830	Poles, Towers & Fixtures	17,269,751	1,391,440	15,878,311	1,225,597	(612,798)	16,491,109	25.00	4.00%	659,644	(391,559)	268,085
1835	OH Conductors & Devices	21,337,432	1,642,813	19,694,619	1,146,367	(573,183)	20,267,803	33.33	3.00%	608,095	(201,347)	406,747
1840	UG Conduit	767,122	-	767,122	2,151	(1,076)	768,197	50.00	2.00%	15,364	(4)	15,360
1845	UG Conductors & Devices	6,214,594	61,865	6,152,729	171,688	(85,881)	6,238,536	33.33	3.00%	187,175	(37,779)	149,396
1850	Line Transformers	10,775,596	919,730	9,855,866	459,916	(230,144)	10,085,638	33.33	3.00%	302,599	(88,985)	213,615
1855	Services (OH & UG)	7,946,600	383,184	7,563,416	694,653	(347,416)	7,910,652	33.33	3.00%	237,343	(16,524)	220,819
1860	Meters	819,719	1,665,988	(846,269)	134,303	(67,152)	(779,117)	33.33	3.00%	(23,376)	89,322	65,946
1860A	Meters	2,421,361	301,615	2,119,745	-	-	2,119,745	25.00	4.00%	84,790	(80,449)	4,341
1860B	Smart Meters	-	-	-	3,120,448	-	3,120,448	15.00	6.67%	208,030		208,030
1861	Smart Meters/Communication Systems	-	-	-	43,405	-	43,405	10.00	10.00%	4,341	(4,341)	(0)
1908	Buildings & Fixtures	852,372	-	852,372	-	-	852,372	50.00	2.00%	17,047		17,047
1910	Leasehold Improvements	418,814	(0)	418,814	53,000	(26,500)	445,314	5.00	20.00%	89,063		89,063
1915	Office Furniture & Equipment 10yr	1,335,241	1,052,758	282,483	3,130	(1,565)	284,048	10.00	10.00%	28,405	(32)	28,373
1920	Computer - Hardware	3,154,470	1,239,919	1,914,551	150,288	(59,288)	2,005,551	5.00	20.00%	401,110	(1,690)	399,420
1925	Computer Software	8,153,314	2,904,813	5,248,501	934,588	(326,719)	5,856,371	10.00	10.00%	585,637	59,942	645,579
1930	Transportation Equipment	3,455,852	575,037	2,880,815	390,000	(195,000)	3,075,815	10.00	10.00%	307,581		307,581
1930A	Transportation Equipment	483,429	235,904	247,525	-	-	247,525	5.00	20.00%	49,505		49,505
1935	Stores Equipment	166,152	119,876	46,277	-	-	46,277	10.00	10.00%	4,628		4,628
1940	Tools, Shop & Garage Equipment	698,297	583,607	114,690	30,343	(15,171)	129,861	10.00	10.00%	12,986	(217)	12,769
1945	Measurement & Testing Equipment	499,998	295,243	204,755	26,355	(13,178)	217,933	10.00	10.00%	21,793	(218)	21,575
1950	Power operated Equipment	109,339	85,203	24,137	-	-	24,137	10.00	10.00%	2,414		2,414
1955	Communications Equipment	938,536	270,262	668,273	21,007	(10,503)	678,777	20.00	5.00%	33,939	56,917	90,856
1960	GA Misc. Equip	293,783	47,908	245,875	213,183	(106,591)	352,467	5.00	20.00%	70,493	(3,051)	67,442
1960A	GA Misc. Equip	59,693	-	59,693	-	-	59,693	10.00	10.00%	5,969		5,969
1980	System Supervisor Equipment	787,135	578,836	208,298	65,111	(32,556)	240,854	10.00	10.00%	24,085	(13,599)	10,486
1980A	System Supervisor Equipment	3,067	3,067	-	-	-	-	5.00	20.00%	-		-
1995	Contributions & Grants	(7,844,111)	(643,367)	(7,200,744)	(285,000)	142,500	(7,343,244)	30.00	3.33%	(244,775)		(244,775)
	Total	92,014,368	13,866,291	78,148,077	9,120,363	(2,822,136)	84,446,304			3,979,012	(699,753)	3,279,260

Less depreciation expense on pre 1999 CIAC	25,505	25,505
Less depreciation expense of allocated assets	957,472	1,017,518
Total Depreciation Expense	2,996,035	2,236,237

Appendix 2-M
Depreciation and Amortization Expense
2013
Port Colborne

Account	Description	Opening Balance Less Leased Assets Aquired in 2012 (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Adjustment for capitalization date	Total for Depreciation (e)=(c) + (d) + adj	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Changes due to MIFRS	MIFRS Depreciation Expense
1806	Land Rights	74,032	0	74,032	50,000	(25,000)	99,032	40.00	2.50%	2,476		2,476
1808	Buildings	241,652	-	241,652	-	-	241,652	50.00	2.00%	4,833		4,833
1820	Substation Equipment	5,803,185	-	5,803,185	453,657	(227,433)	6,029,409	33.33	3.00%	180,900	(56,478)	124,422
1830	Poles, Towers & Fixtures	2,996,662	0	2,996,662	425,532	(212,766)	3,209,428	25.00	4.00%	128,377	(64,571)	63,806
1835	OH Conductors & Devices	3,356,462	-	3,356,462	285,283	(142,992)	3,498,753	33.33	3.00%	104,973	(30,757)	74,217
1840	UG Conduit	265,872	-	265,872	126,254	(63,127)	328,999	50.00	2.00%	6,580	(223)	6,357
1845	UG Conductors & Devices	1,113,534	-	1,113,534	98,524	(49,378)	1,162,680	33.33	3.00%	34,884	(6,483)	28,401
1850	Line Transformers	2,106,783	-	2,106,783	145,758	(73,097)	2,179,444	33.33	3.00%	65,390	(12,593)	52,797
1855	Services (OH & UG)	1,535,900	-	1,535,900	321,383	(160,861)	1,696,422	33.33	3.00%	50,898	(9,064)	41,834
1860	Meters	596,047	(135,842)	731,890	90,573	(45,287)	777,176	25.00	4.00%	31,087	117	31,204
1860B	Smart Meters		-	-	1,644,700	-	1,644,700	15.00	6.67%	109,647		109,647
1865	Other Install on Cust Prem	64,060	(6,504)	70,564	20,413	-	90,977	10.00	10.00%	9,098		9,098
1908	Buildings & Fixtures	140,288	-	140,288	-	-	140,288	50.00	2.00%	2,806		2,806
1915	Office Furniture & Equipment 10yr	22,668	3,813	18,855	-	-	18,855	10.00	10.00%	1,886	976	2,861
1920	Computer - Hardware	93,594	60,598	32,996	4,879	-	37,875	5.00	20.00%	7,575	(976)	6,599
1925	Computer Software	137,859	(33,764)	171,623	167,951	-	339,574	10.00	10.00%	33,957		33,957
1935	Stores Equipment	486	486	-	-	-	-	10.00	10.00%	-		-
1940	Tools, Shop & Garage Equipment	14,089	7,609	6,480	-	-	6,480	10.00	10.00%	648		648
1955	Communications Equipment	115,114	83,363	31,751	-	-	31,751	20.00	5.00%	1,588	3,539	5,127
1980	System Supervisor Equipment	69,804	(0)	69,804	46,590	(23,295)	93,099	10.00	10.00%	9,310	(5,555)	3,755
1995	Contributions & Grants	(2,024,877)	(228,917)	(1,795,960)	(140,000)	70,000	(1,865,960)	30.00	3.33%	(62,199)		(62,199)
	Total	16,723,213	(249,158)	16,972,371	3,741,497	(953,234)	19,760,634			724,713	(182,068)	542,645

Add depreciation expense of acquired assets	464,613	464,613
Add depreciation expense of allocated assets	237,574	253,915
Total Depreciation Expense	1,426,900	1,261,173

Appendix 2-E

Summary of OM&A Epenses - FE and EOP

Table 2: Additional Total OM&A Expense Comparative Information Table

	2011 Actuals	2013 Test	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 5,410,617	$ 5,845,601	$ 434,984	8.04%
	2009 Board-approved	**2013 Test**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ 5,659,126	$ 5,845,601	$ 186,474	3.30%
Simple average of % variance for all years				1.69%
Compound annual growth rate for all years				1.01

	2011 Actuals	MIFRS 2013 Test	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 5,410,617	$ 6,642,960	$ 1,232,343	22.8%
	2009 Board-approved	**MIFRS 2013 Test**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ 5,659,126	$ 6,642,960	$ 983,834	17.4%
Simple average of % variance for all years				4.53%
Compound annual growth rate for all years				1.04

Appendix 2-E
Summary of OM&A Epenses - FE and EOP

Expense Description	2009 Board Approved	2009 Actual	Variance from 2009 EDR	Percent Change from 2009 Board Approved
Distribution Expenses - Operation	1,092,166	780,256	(311,909)	-29%
Distribution Expenses - Maintenance	1,176,848	1,017,747	(159,101)	-14%
Billing and Collection	1,215,240	1,153,666	(61,574)	-5%
Community Relations	47,830	26,301	(21,529)	-45%
Administrative and General Expenses	2,127,042	1,728,030	(399,013)	-19%
Total Operating, Maintenance and Administrative Expenses	5,659,126	4,706,000	(953,126)	-17%
Inflation Rate				

Expense Description	2008 Actual	2009 Actual	Variance from 2008 Actual to 2009 Actual	Percent Change from 2008 Actual to 2009 Actual
Distribution Expenses - Operation	1,005,618	780,256	(225,362)	-22%
Distribution Expenses - Maintenance	1,152,550	1,017,747	(134,803)	-12%
Billing and Collection	1,302,350	1,153,666	(148,683)	-11%
Community Relations	25,461	26,301	840	3%
Administrative and General Expenses	2,019,461	1,728,030	(291,432)	-14%
Total Operating, Maintenance and Administrative Expenses	5,505,440	4,706,000	(799,440)	-15%
Inflation Rate		1.3%		

Expense Description	2009 Actual	2010 Actual	Variance from 2009 Actual to 2010 Actual	Percent Change from 2009 Actual to 2010 Actual
Distribution Expenses - Operation	780,256	930,665	150,409	19%
Distribution Expenses - Maintenance	1,017,747	1,119,821	102,074	10%
Billing and Collection	1,153,666	1,266,553	112,887	10%
Community Relations	26,301	27,566	1,264	5%
Administrative and General Expenses	1,728,030	2,102,573	374,543	22%
Total Operating, Maintenance and Administrative Expenses	4,706,000	5,447,177	741,176	16%
Inflation Rate		1.3%		

Expense Description	2010 Actual	2011 Actual	Variance from 2010 Actual to 2011 Actual	Percent Change from 2010 Actual to 2011 Actual
Distribution Expenses - Operation	930,665	974,144	43,479	5%
Distribution Expenses - Maintenance	1,119,821	1,287,101	167,280	15%
Billing and Collection	1,266,553	1,255,007	(11,546)	-1%
Community Relations	27,566	13,138	(14,427)	-52%
Administrative and General Expenses	2,102,573	1,881,227	(221,345)	-11%
Total Operating, Maintenance and Administrative Expenses	5,447,177	5,410,617	(36,560)	-1%
Inflation Rate		1.7%		

Expense Description	2011 Actual	2012 Bridge	Variance from 2011 Actual to 2012 Bridge	Percent Change from 2011 Actual to 2012 Bridge
Distribution Expenses - Operation	974,144	972,350	(1,794)	0%
Distribution Expenses - Maintenance	1,287,101	1,287,800	699	0%
Billing and Collection	1,255,007	1,278,697	23,689	2%
Community Relations	13,138	14,050	912	7%
Administrative and General Expenses	1,881,227	2,059,275	178,048	9%
Total Operating, Maintenance and Administrative Expenses	5,410,617	5,612,171	201,554	4%
Inflation Rate		2.0%		

Expense Description	2012 Bridge	2013 Test	Variance from 2012 Bridge to 2013 Test	Percent Change from 2012 Bridge to 2013 Test
Distribution Expenses - Operation	972,350	942,827	(29,522)	-3%
Distribution Expenses - Maintenance	1,287,800	1,316,640	28,840	2%
Billing and Collection	1,278,697	1,336,847	58,150	5%
Community Relations	14,050	27,700	13,650	97%
Administrative and General Expenses	2,059,275	2,221,587	162,312	8%
Total Operating, Maintenance and Administrative Expenses	5,612,171	5,845,601	233,430	4%
Inflation Rate		2.0%		

Expense Description	2012 Bridge	MIFRS 2013 Test	Variance from 2012 Bridge to MIFRS 2013 Test	Percent Change from 2012 Bridge to MIFRS 2013 Test
Distribution Expenses - Operation	972,350	979,754	7,404	1%
Distribution Expenses - Maintenance	1,287,800	1,316,640	28,840	2%
Billing and Collection	1,278,697	1,336,847	58,150	5%
Community Relations	14,050	27,700	13,650	97%
Administrative and General Expenses	2,059,275	2,982,020	922,745	45%
Total Operating, Maintenance and Administrative Expenses	5,612,171	6,642,960	1,030,790	18%
Inflation Rate		2.0%		

Appendix 2-F
OM & A Detailed Costs Table - FE and EOP

OEB Account	Expense Description	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
	Distribution Expenses - Operation							
5005	Operation Supervision and Engineering	69,245	68,088	101,285	77,853	100,859		100,859
5010	Load Dispatching	162,983	174,280	155,499	188,972	164,182		164,182
5012	Station Buildings and Fixtures Expense	97,124	103,678	130,309	125,256	118,200		118,200
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-		-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-		-
5016	Distribution Station Equipment - Operation Labour	55,353	102,711	74,945	53,318	50,764		50,764
5017	Distribution Station Equipment - Operation Supplies and Expenses	13,830	12,086	10,719	13,796	13,920		13,920
5020	Overhead Distribution Lines and Feeders - Operation Labour	64,648	55,320	53,193	65,171	50,180		50,180
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	17,810	18,624	15,027	19,620	15,720		15,720
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-		-
5035	Overhead Distribution Transformers- Operation	7,950	13,894	1,163	8,227	1,580		1,580
5040	Underground Distribution Lines and Feeders - Operation Labour	81,575	88,292	99,047	91,709	116,706		116,706
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	778	(158)	1,012	1,000	1,600		1,600
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-		-
5055	Underground Distribution Transformers - Operation	-	1,161	-	1,870	1,519		1,519
5065	Meter Expense	137,333	204,275	223,222	197,479	201,118		201,118
5070	Customer Premises - Operation Labour	164	-	238	44,213	13,722		13,722
5075	Customer Premises - Materials and Expenses	717	-	-	4,800	6,000		6,000
5085	Miscellaneous Distribution Expense	70,746	87,962	108,171	79,065	86,756	36,927	123,682
5090	Underground Distribution Lines and Feeders - Rental Paid	-	451	315	-	-		-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-		-
5096	Other Rent	-	-	-	-	-		-
	Distribution Expenses - Operation Total	**780,256**	**930,665**	**974,144**	**972,350**	**942,827**	**36,927**	**979,754**
	Distribution Expenses - Maintenance							
5105	Maintenance Supervision and Engineering	15,840	45,927	69,536	54,831	51,543		51,543
5110	Maintenance of Buildings and Fixtures - Distribution Stations	9,005	12,764	26,554	7,122	22,841		22,841
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-		-
5114	Maintenance of Distribution Station Equipment	44,643	63,941	72,501	89,748	86,811		86,811
5120	Maintenance of Poles, Towers and Fixtures	32,662	50,171	45,547	43,359	44,170		44,170
5125	Maintenance of Overhead Conductors and Devices	162,041	163,130	173,016	165,178	186,962		186,962
5130	Maintenance of Overhead Services	206,534	200,996	215,665	206,404	192,082		192,082
5135	Overhead Distribution Lines and Feeders - Right of Way	321,931	310,941	314,480	320,187	339,364		339,364
5145	Maintenance of Underground Conduit	-	450	606	-	-		-
5150	Maintenance of Underground Conductors and Devices	16,222	28,863	27,101	30,484	30,022		30,022
5155	Maintenance of Underground Services	22,698	21,646	44,016	25,011	33,877		33,877
5160	Maintenance of Line Transformers	104,009	115,971	94,589	116,265	73,185		73,185
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-		-
5170	Sentinel Lights - Labour	-	-	-	-	-		-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-		-
5175	Maintenance of Meters	81,946	104,794	203,490	228,910	255,783		255,783
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-		-
5195	Maintenance of Other Installations on Customer Premises	216	226	-	300	-		-
	Distribution Expenses - Maintenance Total	**1,017,747**	**1,119,821**	**1,287,101**	**1,287,800**	**1,316,640**		**1,316,640**
	Billing and Collection							
5305	Supervision	56,233	75,473	78,088	126,655	104,555		104,555
5310	Meter Reading Expense	253,771	178,238	40,740	41,521	53,354		53,354
5315	Customer Billing	254,390	296,090	318,957	338,481	366,923		366,923
5320	Collecting	171,179	215,377	213,400	276,243	252,724		252,724
5325	Collecting- Cash Over and Short	-	-	-	-	-		-
5330	Collection Charges	-	-	-	-	-		-
5335	Bad Debt Expense	87,254	129,715	145,410	140,000	160,000		160,000
5340	Miscellaneous Customer Accounts Expenses	330,840	371,660	458,413	355,798	399,291		399,291
	Billing and Collection Total	**1,153,666**	**1,266,553**	**1,255,007**	**1,278,697**	**1,336,847**		**1,336,847**

Appendix 2-F Continued

	Community Relations							
5405	Supervision	-	-	-	-	-		-
5410	Community Relations - Sundry	13,475	6,076	750	-	-		-
5415	Energy Conservation	-	-	-	-	-		-
5420	Community Safety Program	-	-	-	-	4,200		4,200
5425	Miscellaneous Customer Service and Informational Expenses	8,945	7,621	10,168	9,400	18,500		18,500
5505	Supervision	-	-	-	-	-		-
5510	Demonstrating and Selling Expense	-	-	-	-	-		-
5515	Advertising Expense	-	-	-	-	-		-
5660	General Advertising Expenses	3,881	13,869	2,220	4,650	5,000		5,000
	Community Relations Total	**26,301**	**27,566**	**13,138**	**14,050**	**27,700**		**27,700**
	Administrative and General Expenses							
5605	Executive Salaries and Expenses	-	-	-	-	-		-
5610	Management Salaries and Expenses	-	-	-	-	-		-
5615	General Administrative Salaries and Expenses	2,600,592	2,983,349	3,177,159	3,858,761	3,947,271		3,947,271
5620	Office Supplies and Expenses	272,768	394,158	372,791	494,401	521,137		521,137
5625	Administrative Expense Transferred/Credit	(3,393,538)	(3,570,565)	(4,222,883)	(5,394,671)	(5,475,410)	760,433	(4,714,977)
5630	Outside Services Employed	217,590	252,427	304,875	354,796	392,764		392,764
5635	Property Insurance	53,169	42,219	39,824	42,700	39,400		39,400
5640	Injuries and Damages	525	-	-	-	-		-
5645	Employee Pensions and Benefits	598,461	697,565	866,151	1,160,051	1,189,718		1,189,718
5650	Franchise Requirements	-	-	-	-	-		-
5655	Regulatory Expenses	197,252	156,685	163,234	193,955	191,623		191,623
5665	Miscellaneous General Expenses	83,315	100,069	65,527	123,320	165,397		165,397
5670	Rent	247,166	252,110	254,049	218,664	223,037		223,037
5675	Maintenance of General Plant	854,318	800,543	846,033	992,847	1,012,179		1,012,179
5680	Electrical Safety Authority Fees	-	-	-	-	-		-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-		-
5695	OM&A Contra Account	(3,589)	(5,987)	-	-	-		-
6205	Donations	-	-	14,469	14,450	14,470		14,470
	Administrative and General Expenses Total	**1,728,030**	**2,102,573**	**1,881,227**	**2,059,275**	**2,221,587**	**760,433**	**2,982,020**
	Total Operating, Maintenance and Administrative Expenses	**4,706,000**	**5,447,177**	**5,410,617**	**5,612,171**	**5,845,601**	**797,360**	**6,642,960**

Appendix 2-G
OM&A Cost Driver Table
FE and EOP

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Opening Balances	**5,659,126**	**4,706,001**	**5,447,177**	**5,410,617**	**5,612,171**		**5,612,171**
Revised shared cost allocations	**(43,735)**	**(177,026)**	**(652,318)**	**(1,171,788)**	**(80,740)**		**(80,740)**
General Administrative Salaries and Expenses		**382,758**	**193,809**	**681,603**	**88,510**		**88,510**
Empolyee pension and benefit	**(73,153)**	**99,104**	**168,586**	**293,900**	**29,667**		**29,667**
Office supplies and expenses	**(93,907)**	**121,390**		**121,610**	**26,736**		**26,736**
Meter Reading Expense		**(75,533)**	**(137,498)**				
Miscellaneous Customer Accounts Expenses		**40,820**	**86,753**	**(102,615)**	**43,494**		**43,494**
Customer Billing	**(70,319)**	**41,700**					
Collecting		**44,199**		**62,843**			
Bad Debt Expense		**42,461**					
Maintenance of General Plant	**(78,406)**	**(53,775)**		**146,814**			
Outside Services Employed	**(52,505)**		**52,448**	**49,922**			
Property insurance	**(63,031)**						
Distribution maintenance activities	**(159,101)**	**102,074**	**167,280**				
Distribution operating activities	**(311,909)**	**150,409**					
GEC						**760,433**	**760,433**
Labour rate change						**36,927**	**36,927**
Miscellaneous other	**(7,060)**	**22,596**	**84,381**	**119,265**	**125,762**		**125,762**
Closing Balances	**4,706,001**	**5,447,177**	**5,410,617**	**5,612,171**	**5,845,601**		**6,642,961**

Appendix 2-I
OM&A Cost per Customer and FTEE - FE and EOP

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Number of Customers	19,344	19,149	19,159	19,304	19,390	19,472		19,472
Total OM&A from Appendix 2-F	$ 5,659,126	$ 4,706,000	$ 5,447,177	$ 5,410,617	$ 5,612,171	$ 5,845,601	$ 797,360	$ 6,642,960
OM&A cost per Customer	$ 293	$ 246	$ 284	$ 280	$ 289	$ 300		$ 341
Number of FTEEs	45.34	45.34	46.18	46.18	46.61	46.61		46.61
FTEEs/Customer	0.0023	0.0024	0.0024	0.0024	0.0024	0.0024		0.0024
OM&A cost per FTEE	$ 124,815	$ 103,794	$ 117,955	$ 117,164	$ 120,407	$ 125,415		$ 142,522

The number of FTEEs is based on the methodology described in the. BDR report.

OM & A Detailed Costs Table
FE and EOP

OEB Account	Expense Description	2009 Board Approved	2009 Actual	Variance from 2009 EDR	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge	Variance from 2011 Actual	2013 Test	Variance from 2012 Bridge	Changes due to MIFRS	MIFRS 2013 Test
	Distribution Expenses - Operation													
5005	Operation Supervision and Engineering	82,483	69,245	(13,239)	68,088	(1,157)	101,285	33,197	77,853	(23,432)	100,859	23,007		100,859
5010	Load Dispatching	196,095	162,983	(33,111)	174,280	11,297	155,499	(18,782)	188,972	33,473	164,182	(24,790)		164,182
5012	Station Buildings and Fixtures Expense	92,992	97,124	4,132	103,678	6,554	130,309	26,631	125,256	(5,053)	118,200	(7,056)		118,200
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-		-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-		-
5016	Distribution Station Equipment - Operation Labour	193,407	55,353	(138,055)	102,711	47,359	74,945	(27,766)	53,318	(21,627)	50,764	(2,554)		50,764
5017	Distribution Station Equipment - Operation Supplies and Expenses	3,600	13,830	10,230	12,086	(1,744)	10,719	(1,367)	13,796	3,078	13,920	124		13,920
5020	Overhead Distribution Lines and Feeders - Operation Labour	35,594	64,648	29,055	55,320	(9,329)	53,193	(2,127)	65,171	11,978	50,180	(14,991)		50,180
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	26,400	17,810	(8,590)	18,624	814	15,027	(3,597)	19,620	4,593	15,720	(3,900)		15,720
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-		-
5035	Overhead Distribution Transformers- Operation	11,587	7,950	(3,637)	13,894	5,944	1,163	(12,731)	8,227	7,064	1,580	(6,647)		1,580
5040	Underground Distribution Lines and Feeders - Operation Labour	95,009	81,575	(13,434)	88,292	6,717	99,047	10,755	91,709	(7,337)	116,706	24,997		116,706
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	1,200	778	(422)	(158)	(936)	1,012	1,170	1,000	(12)	1,600	600		1,600
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-		-
5055	Underground Distribution Transformers - Operation	4,165	-	(4,165)	1,161	1,161	-	(1,161)	1,870	1,870	1,519	(351)		1,519
5065	Meter Expense	168,067	137,333	(30,734)	204,275	66,943	223,222	18,947	197,479	(25,743)	201,118	3,640		201,118
5070	Customer Premises - Operation Labour	592	164	(428)	-	(164)	238	238	44,213	43,975	13,722	(30,491)		13,722
5075	Customer Premises - Materials and Expenses	8,400	717	(7,683)	-	(717)	-	-	4,800	4,800	6,000	1,200		6,000
5085	Miscellaneous Distribution Expense	172,576	70,746	(101,830)	87,962	17,216	108,171	20,209	79,065	(29,106)	86,756	7,691	36,927	123,682
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	451	451	315	(136)	-	(315)	-	-		-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-		-
5096	Other Rent	-	-	-	-	-	-	-	-	-	-	-		-
	Distribution Expenses - Operation Total	**1,092,166**	**780,256**	**(311,909)**	**930,665**	**150,409**	**974,144**	**43,479**	**972,350**	**(1,794)**	**942,827**	**(29,522)**	**36,927**	**979,754**
	Distribution Expenses - Maintenance													
5105	Maintenance Supervision and Engineering	24,455	15,840	(8,615)	45,927	30,087	69,536	23,609	54,831	(14,705)	51,543	(3,288)		51,543
5110	Maintenance of Buildings and Fixtures - Distribution Stations	11,502	9,005	(2,497)	12,764	3,759	26,554	13,790	7,122	(19,431)	22,841	15,719		22,841
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-		-
5114	Maintenance of Distribution Station Equipment	39,492	44,643	5,151	63,941	19,298	72,501	8,559	89,748	17,247	86,811	(2,937)		86,811
5120	Maintenance of Poles, Towers and Fixtures	44,250	32,662	(11,588)	50,171	17,510	45,547	(4,624)	43,359	(2,188)	44,170	810		44,170
5125	Maintenance of Overhead Conductors and Devices	207,149	162,041	(45,108)	163,130	1,089	173,016	9,886	165,178	(7,838)	186,962	21,784		186,962
5130	Maintenance of Overhead Services	228,364	206,534	(21,830)	200,996	(5,539)	215,665	14,670	206,404	(9,262)	192,082	(14,321)		192,082
5135	Overhead Distribution Lines and Feeders - Right of Way	284,660	321,931	37,271	310,941	(10,990)	314,480	3,538	320,187	5,708	339,364	19,177		339,364
5145	Maintenance of Underground Conduit	692	-	(692)	450	450	606	156	-	(606)	-	-		-
5150	Maintenance of Underground Conductors and Devices	70,644	16,222	(54,422)	28,863	12,641	27,101	(1,762)	30,484	3,383	30,022	(463)		30,022
5155	Maintenance of Underground Services	83,556	22,698	(60,858)	21,646	(1,052)	44,016	22,370	25,011	(19,005)	33,877	8,865		33,877
5160	Maintenance of Line Transformers	69,510	104,009	34,499	115,971	11,962	94,589	(21,382)	116,265	21,675	73,185	(43,080)		73,185
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-		-
5170	Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-		-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-		-
5175	Maintenance of Meters	108,973	81,946	(27,027)	104,794	22,848	203,490	98,696	228,910	25,420	255,783	26,873		255,783
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-	-	-		-
5195	Maintenance of Other Installations on Customer Premises	3,600	216	(3,384)	226	10	-	(226)	300	300	-	(300)		-
	Distribution Expenses - Maintenance Total	**1,176,848**	**1,017,747**	**(159,101)**	**1,119,821**	**102,074**	**1,287,101**	**167,280**	**1,287,800**	**699**	**1,316,640**	**28,840**	**-**	**1,316,640**

OM&A Detailed Costs Table – Continued
FE and EOP

	Billing and Collection													
5305	Supervision	93,534	56,233	(37,301)	75,473	19,241	78,088	2,615	126,655	48,567	104,555	(22,101)		104,555
5310	Meter Reading Expense	228,303	253,771	25,468	178,238	(75,533)	40,740	(137,498)	41,521	781	53,354	11,833		53,354
5315	Customer Billing	324,709	254,390	(70,319)	296,090	41,700	318,957	22,866	338,481	19,524	366,923	28,442		366,923
5320	Collecting	161,693	171,179	9,485	215,377	44,199	213,400	(1,977)	276,243	62,843	252,724	(23,518)		252,724
5325	Collecting- Cash Over and Short	-	-	-	-	-	-	-	-	-	-	-		-
5330	Collection Charges	-	-	-	-	-	-	-	-	-	-	-		-
5335	Bad Debt Expense	64,400	87,254	22,854	129,715	42,461	145,410	15,695	140,000	(5,410)	160,000	20,000		160,000
5340	Miscellaneous Customer Accounts Expenses	342,601	330,840	(11,761)	371,660	40,820	458,413	86,753	355,798	(102,615)	399,291	43,494		399,291
	Billing and Collection Total	**1,215,240**	**1,153,666**	**(61,574)**	**1,266,553**	**112,887**	**1,255,007**	**(11,546)**	**1,278,697**	**23,689**	**1,336,847**	**58,150**	**-**	**1,336,847**
	Community Relations													
5405	Supervision	-	-	-	-	-	-	-	-	-	-	-		-
5410	Community Relations - Sundry	21,064	13,475	(7,589)	6,076	(7,399)	750	(5,326)	-	(750)	-	-		-
5415	Energy Conservation	1,000	-	(1,000)	-	-	-	-	-	-	-	-		-
5420	Community Safety Program	6,400	-	(6,400)	-	-	-	-	-	-	4,200	4,200		4,200
5425	Miscellaneous Customer Service and Informational Expenses	16,366	8,945	(7,421)	7,621	(1,324)	10,168	2,547	9,400	(768)	18,500	9,100		18,500
5505	Supervision	-	-	-	-	-	-	-	-	-	-	-		-
5510	Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-		-
5515	Advertising Expense	-	-	-	-	-	-	-	-	-	-	-		-
5660	General Advertising Expenses	3,000	3,881	881	13,869	9,988	2,220	(11,649)	4,650	2,430	5,000	350		5,000
	Community Relations Total	**47,830**	**26,301**	**(21,529)**	**27,566**	**1,264**	**13,138**	**(14,427)**	**14,050**	**912**	**27,700**	**13,650**	**-**	**27,700**
	Administrative and General Expenses													
5605	Executive Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-		-
5610	Management Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-		-
5615	General Administrative Salaries and Expenses	2,601,540	2,600,592	(948)	2,983,349	382,758	3,177,159	193,809	3,858,761	681,603	3,947,271	88,510		3,947,271
5620	Office Supplies and Expenses	366,675	272,768	(93,907)	394,158	121,390	372,791	(21,367)	494,401	121,610	521,137	26,736		521,137
5625	Administrative Expense Transferred/Credit	(3,349,803)	(3,393,538)	(43,735)	(3,570,565)	(177,026)	(4,222,883)	(652,318)	(5,394,671)	(1,171,788)	(5,475,410)	(80,740)	760,433	(4,714,977)
5630	Outside Services Employed	270,096	217,590	(52,505)	252,427	34,837	304,875	52,448	354,796	49,922	392,764	37,968		392,764
5635	Property Insurance	116,200	53,169	(63,031)	42,219	(10,950)	39,824	(2,396)	42,700	2,876	39,400	(3,300)		39,400
5640	Injuries and Damages	-	525	525	-	(525)	-	-	-	-	-	-		-
5645	Employee Pensions and Benefits	671,614	598,461	(73,153)	697,565	99,104	866,151	168,586	1,160,051	293,900	1,189,718	29,667		1,189,718
5650	Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-		-
5655	Regulatory Expenses	196,991	197,252	261	156,685	(40,568)	163,234	6,550	193,955	30,721	191,623	(2,332)		191,623
5665	Miscellaneous General Expenses	73,840	83,315	9,475	100,069	16,754	65,527	(34,541)	123,320	57,793	165,397	42,077		165,397
5670	Rent	247,166	247,166	-	252,110	4,943	254,049	1,939	218,664	(35,385)	223,037	4,373		223,037
5675	Maintenance of General Plant	932,724	854,318	(78,406)	800,543	(53,775)	846,033	45,490	992,847	146,814	1,012,179	19,332		1,012,179
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-	-	-	-	-		-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-		-
5695	OM&A Contra Account	-	(3,589)	(3,589)	(5,987)	(2,398)	-	5,987	-	-	-	-		-
6205	Donations	-	-	-	-	-	14,469	14,469	14,450	(19)	14,470	20		14,470
	Administrative and General Expenses Total	**2,127,042**	**1,728,030**	**(399,013)**	**2,102,573**	**374,543**	**1,881,227**	**(221,345)**	**2,059,275**	**178,048**	**2,221,587**	**162,312**	**760,433**	**2,982,020**

OM&A Detailed Costs Table – Continued
FE and EOP

	Taxes Other Than Income Taxes												
6105	Taxes Other Than Income Taxes (Note less capital taxes)	59,000	63,737	4,737	35,376	(28,361)	60,149	24,773	55,500	(4,649)	62,600	7,100	62,600
	Taxes Total	**59,000**	**63,737**	**4,737**	**35,376**	**(28,361)**	**60,149**	**24,773**	**55,500**	**(4,649)**	**62,600**	**7,100**	**-**	**62,600**
	Total Operating, Maintenance and Administrative Expenses	**5,718,126**	**4,769,738**	**(948,389)**	**5,482,553**	**712,815**	**5,470,766**	**(11,787)**	**5,667,671**	**196,905**	**5,908,201**	**240,530**	**797,360**	**6,705,560**
	Power Supply Expenses												
4705	Power Purchased	21,511,407	20,850,603	(660,804)	23,499,918	2,649,315	24,867,724	1,367,806	26,317,776	1,450,053	26,322,125	4,349		26,322,125
4708	Charges-WMS	2,347,702	2,230,164	(117,538)	2,318,995	88,832	2,286,611	(32,384)	2,242,017	(44,594)	2,192,061	(49,957)		2,192,061
4710	Cost of Power Adjustments	-	-	-	-	-	-	-	-	-	-	-		-
4712	Charges-One-Time	-	-	-	-	-	-	-	-	-	-	-		-
4714	Charges-NW	1,724,442	1,572,131	(152,311)	1,844,966	272,835	1,978,534	133,569	2,066,535	88,001	2,280,061	213,527		2,280,061
4716	Charges-CN	1,661,809	1,540,447	(121,362)	1,668,341	127,893	1,670,100	1,759	1,695,078	24,978	1,787,432	92,354		1,787,432
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-	-	-	-		-
4750	Charges - LV	95,837	92,971	(2,867)	48,046	(44,924)	91,709	43,663	91,464	(245)	91,709	245		91,709
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-		-
	Power Supply Expenses Total	**27,341,197**	**26,286,316**	**(1,054,882)**	**29,380,266**	**3,093,950**	**30,894,679**	**1,514,413**	**32,412,870**	**1,518,192**	**32,673,389**	**260,518**	**-**	**32,673,389**
	Total Expenses for Working Capital	**33,059,324**	**31,056,054**	**(2,003,270)**	**34,862,819**	**3,806,766**	**36,365,444**	**1,502,625**	**38,080,541**	**1,715,097**	**38,581,589**	**501,048**	**797,360**	**39,378,949**
	Amortization Expenses												
5705	Amortization Expense - Property, Plant, and Equipment	2,459,267	2,948,944	489,677	2,547,873	(401,071)	2,418,556	(129,317)	2,416,711	(1,844)	2,996,035	579,324	(759,798)	2,236,237
5715	Amortization of Intangibles and Other Electric Plant	-	2,479	2,479	2,479	-	2,479	(0)	-	(2,479)	-	-		-
	Amortization Expenses Total	**2,459,267**	**2,951,423**	**492,156**	**2,550,352**	**(401,071)**	**2,421,035**	**(129,317)**	**2,416,711**	**(4,324)**	**2,996,035**	**579,324**	**(759,798)**	**2,236,237**
	Grand Total	**35,518,590**	**34,007,476**	**(1,511,114)**	**37,413,171**	**3,405,695**	**38,786,479**	**1,373,308**	**40,497,253**	**1,710,773**	**41,577,624**	**1,080,372**	**37,562**	**41,615,186**

TAX CALCULATIONS - FE and EOP

Description	TOTAL CNPI 2009 Actual	TRANSMISSION 2009 Actual	DISTRIBUTION 2009 Actual	TOTAL CNPI 2010 Actual	TRANSMISSION 2010 Actual	DISTRIBUTION 2010 Actual	TOTAL CNPI 2011 Forecast	TRANSMISSION 2011 Forecast	DISTRIBUTION 2011 Forecast	TOTAL CNPI 2012 Regulatory	TRANSMISSION 2012 Forecast	DISTRIBUTION 2012 Regulatory	TOTAL CNPI 2013 Regulatory	TRANSMISSION 2013 Forecast	DISTRIBUTION 2013 Regulatory	Changes due to MIFRS	MIFRS DISTRIBUTION 2013 Regulatory
Net income(loss) per financial statements	3,024,635	1,323,074	1,701,561	3,121,711	1,504,497	1,617,214	3,005,857	1,555,846	1,450,011	-	-	-	-	-	-		-
Utility income before taxes	-	-	-	-	-	-	-	-	-	3,450,067	1,236,000	2,214,067	3,893,068	1,215,000	2,678,068	1,841	2,679,909
Add:																	
Provision for income taxes - current	878,461	395,534	482,927	573,810	275,206	298,604	188,737	100,033	88,704	-	-	-	-	-	-		-
Amortization of assets	4,075,289	756,056	3,319,233	4,262,383	762,455	3,499,928	4,452,997	765,727	3,687,270	5,363,652	884,000	4,479,652	6,069,339	901,000	5,168,339	(881,820)	4,286,519
SHRED	64,716	-	64,716	-	-	-	-	-	-	-	-	-	-	-	-		-
Donations	27,100	2,389	24,711	-	-	-	-	-	-	-	-	-	-	-	-		-
Non-deductible meals and entertainment	17,858	1,574	16,284	19,228	2,523	16,705	19,000	2,493	16,507	19,000	2,493	16,507	19,000	2,493	16,507		16,507
Reserves from financial statements - EOY	2,357,583	207,811	2,149,772	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918	1,676,000	219,924	1,456,076		1,456,076
Amortization of deferred financing	32,028	12,798	19,230	32,028	10,776	21,252	32,028	7,393	24,635	32,028	7,299	24,729	32,028	7,212	24,816		24,816
Amortization of deferred lease costs	58,140	-	58,140	58,140	-	58,140	58,140	-	58,140	19,380	-	19,380	-	-	-		-
Ontario apprentice and co-op tax credits	4,333	382	3,951	11,274	1,479	9,795	4,000	525	3,475	4,000	525	3,475	4,000	525	3,475		3,475
Total Additions	7,515,508	1,376,544	6,138,964	7,115,278	1,335,665	5,779,613	6,609,902	1,119,583	5,490,319	7,260,060	1,133,399	6,126,661	7,800,367	1,131,153	6,669,213	(881,820)	5,787,393
Deduct:																	
Gain on disposal of assets per financial statements	51,467	-	51,467	37,802	-	37,802	25,266	-	25,266	-	-	-	-	-	-		-
Capital cost allowance	4,178,748	554,313	3,624,435	5,102,785	538,668	4,564,117	5,592,886	524,476	5,068,410	5,672,863	680,078	4,992,785	5,960,047	861,745	5,098,302		5,098,302
Cumulative eligible capital deduction	7,781	(0)	7,781	7,237	-	7,237	6,730	-	6,730	6,259	-	6,259	6,259	-	6,259		6,259
Reserves from financial statements - BOY	2,386,859	210,392	2,176,467	2,357,583	309,361	2,048,222	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918		1,582,918
Allowance for funds used during construction	116,308	116,308	-	16,338	16,338	-	-	-	-	-	-	-	-	-	-		-
Capitalized general expense	1,015,195	-	1,015,195	970,154	-	970,154	980,256	-	980,256	1,069,910	-	1,069,910	1,112,726	-	1,112,726	(1,112,726)	(0)
Total Deductions	7,756,358	881,013	6,875,345	8,491,899	864,366	7,627,532	8,763,553	807,702	7,955,851	8,604,032	923,489	7,680,542	8,901,032	1,100,827	7,800,205	(1,112,726)	6,687,479
Taxable Income	2,783,785	1,818,605	965,180	1,745,090	1,975,796	(230,706)	852,206	1,867,727	(1,015,521)	2,106,095	1,445,909	660,186	2,792,403	1,245,327	1,547,076	232,747	1,779,823
Corporate tax rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	739,987	330,012	409,975	61,678	471,653
Grossed Up Taxes															557,789	83,916	641,705
Calculation of total taxes																	
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	887,801	330,012	557,789	83,916	641,705
Ontario apprentice and co-op tax credits	-	-	-	(9,416)	(1,236)	(8,180)	-	-	-	-	-	-	-	-	-		-
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777	-	-	-	-	-	-	-	-	-		-
Total taxes	**1,136,360**	**687,131**	**449,229**	**600,550**	**634,472**	**(33,922)**	**240,748**	**527,633**	**(286,885)**	**558,115**	**383,166**	**174,949**	**887,801**	**330,012**	**557,789**	**83,916**	**641,705**
Tax Rates																	
Federal Tax	19.00%	19.00%	19.00%	18.00%	18.00%	18.00%	16.50%	16.50%	16.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%		15.00%
Provincial Tax	14.00%	14.00%	14.00%	13.00%	13.00%	13.00%	11.75%	11.75%	11.75%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%		11.50%
Total Tax Rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%
Calculation of Ontario Capital Tax																	
Net Paid Up Capital	99,498,319	39,756,937	59,741,382	95,514,739	32,135,669	63,379,070											
Less Exemption	2,738,073	1,094,063	1,644,010	2,768,091	931,317	1,836,774											
Taxable Capital/Deemed Taxable Capital	96,760,246	38,662,874	58,097,372	92,746,648	31,204,352	61,542,296											
OCT Rate	0.225%	0.225%	0.225%	0.074%	0.074%	0.074%											
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777											
FORT ERIE AND EOP RATE BASE			45,600,794			47,647,860			48,535,033			50,493,373			52,680,275	102,559	52,782,834
% OF TOTAL RATE BASE			76%			75%			75%			73%			72%		72%
TOTAL TAXES			**342,898**			**(25,502)**			**(214,384)**			**127,835**			**400,269**	**60,797**	**461,066**

Total Operations, Maintenance, and Administrative Expenses - FE and EOP

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Operating	1,092,166	780,256	930,665	974,144	972,350	942,827	36,927	979,754
Maintenance	1,176,848	1,017,747	1,119,821	1,287,101	1,287,800	1,316,640		1,316,640
Billing and Collection	1,215,240	1,153,666	1,266,553	1,255,007	1,278,697	1,336,847		1,336,847
Community Relations	47,830	26,301	27,566	13,138	14,050	27,700		27,700
Administrative and General	2,127,042	1,728,030	2,102,573	1,881,227	2,059,275	2,221,587	760,433	2,982,020
Taxes Other than Income Taxes	59,000	63,737	35,376	60,149	55,500	62,600		62,600
	5,718,126	4,769,738	5,482,553	5,470,766	5,667,671	5,908,201	797,360	6,705,560

Total Operations, Maintenance, and Administrative Expenses - PC

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Operating	410,703	360,324	407,031	508,007	444,089	493,132	(8,339)	484,794
Maintenance	545,753	442,988	545,428	540,395	646,529	595,838		595,838
Billing and Collection	612,519	576,667	533,156	632,381	695,617	724,206		724,206
Community Relations	23,698	14,579	10,034	6,901	5,000	13,000		13,000
Administrative and General	2,086,552	2,046,190	1,996,383	1,992,874	1,325,663	956,170	352,293	1,308,463
Taxes Other than Income Taxes	70,000	53,880	52,557	52,024	55,000	54,100		54,100
	3,749,224	3,494,628	3,544,589	3,732,582	3,171,898	2,836,446	343,954	3,180,400

Appendix 2-E
Summary of OM&A Epenses - Port Colborne

Table 2: Additional Total OM&A Expense Comparative Information Table

	2011 Actuals	2013 Test	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 3,680,558	$ 2,782,346	-$ 898,212	-24.40%
	2009 Board-approved	**2013 Test**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ 3,679,224	$ 2,782,346	-$ 896,878	-24.38%
Simple average of % variance for all years				-5.14%
Compound annual growth rate for all years				0.91

	2011 Actuals	MIFRS 2013 Test	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 3,680,558	$ 3,126,300	-$ 554,257	-15.06%
	2009 Board-approved	**MIFRS 2013 Test**	**Variance $**	**Percentage Change %**
Test Year versus LRY Board-approved	$ 3,679,224	$ 3,126,300	-$ 552,924	-15.03%
Simple average of % variance for all years				-2.93%
Compound annual growth rate for all years				0.95

Appendix 2-E
Summary of OM&A Epenses - Port Colborne

Expense Description	2009 Board Approved	2009 Actual	Variance from 2009 EDR	Percent Change from 2009 Board Approved
Distribution Expenses - Operation	410,703	360,324	(50,379)	-12%
Distribution Expenses - Maintenance	545,753	442,988	(102,765)	-19%
Billing and Collection	612,519	576,667	(35,852)	-6%
Community Relations	23,698	14,579	(9,119)	-38%
Administrative and General Expenses	2,086,552	2,046,190	(40,362)	-2%
Total Operating, Maintenance and Administrative Expenses	3,679,224	3,440,747	(238,477)	-6%
Inflation Rate				

Expense Description	2008 Actual	2009 Actual	Variance from 2008 Actual to 2009 Actual	Percent Change from 2008 Actual to 2009 Actual
Distribution Expenses - Operation	408,757	360,324	(48,433)	-12%
Distribution Expenses - Maintenance	367,724	442,988	75,264	20%
Billing and Collection	625,441	576,667	(48,775)	-8%
Community Relations	10,853	14,579	3,726	34%
Administrative and General Expenses	2,267,963	2,046,190	(221,773)	-10%
Total Operating, Maintenance and Administrative Expenses	3,680,739	3,440,747	(239,992)	-7%
Inflation Rate		1.3%		

Expense Description	2009 Actual	2010 Actual	Variance from 2009 Actual to 2010 Actual	Percent Change from 2009 Actual to 2010 Actual
Distribution Expenses - Operation	360,324	407,031	46,707	13%
Distribution Expenses - Maintenance	442,988	545,428	102,440	23%
Billing and Collection	576,667	533,156	(43,511)	-8%
Community Relations	14,579	10,034	(4,545)	-31%
Administrative and General Expenses	2,046,190	1,996,383	(49,807)	-2%
Total Operating, Maintenance and Administrative Expenses	3,440,747	3,492,032	51,285	1%
Inflation Rate		1.3%		

Expense Description	2010 Actual	2011 Actual	Variance from 2010 Actual to 2011 Actual	Percent Change from 2010 Actual to 2011 Actual
Distribution Expenses - Operation	407,031	508,007	100,976	25%
Distribution Expenses - Maintenance	545,428	540,395	(5,033)	-1%
Billing and Collection	533,156	632,381	99,225	19%
Community Relations	10,034	6,901	(3,132)	-31%
Administrative and General Expenses	1,996,383	1,992,874	(3,509)	0%
Total Operating, Maintenance and Administrative Expenses	3,492,032	3,680,558	188,526	5%
Inflation Rate		1.7%		

Expense Description	2011 Actual	2012 Bridge	Variance from 2011 Actual to 2012 Bridge	Percent Change from 2011 Actual to 2012 Bridge
Distribution Expenses - Operation	508,007	444,089	(63,918)	-13%
Distribution Expenses - Maintenance	540,395	646,529	106,134	20%
Billing and Collection	632,381	695,617	63,236	10%
Community Relations	6,901	5,000	(1,901)	-28%
Administrative and General Expenses	1,992,874	1,325,663	(667,210)	-33%
Total Operating, Maintenance and Administrative Expenses	3,680,558	3,116,898	(563,660)	-15%
Inflation Rate		2.0%		

Expense Description	2012 Bridge	2013 Test	Variance from 2012 Bridge to 2013 Test	Percent Change from 2012 Bridge to 2013 Test
Distribution Expenses - Operation	444,089	493,132	49,043	11%
Distribution Expenses - Maintenance	646,529	595,838	(50,691)	-8%
Billing and Collection	695,617	724,206	28,589	4%
Community Relations	5,000	13,000	8,000	160%
Administrative and General Expenses	1,325,663	956,170	(369,493)	-28%
Total Operating, Maintenance and Administrative Expenses	3,116,898	2,782,346	(334,552)	-11%
Inflation Rate		2.0%		

Expense Description	2012 Bridge	MIFRS 2013 Test	Variance from 2012 Bridge to MIFRS 2013 Test	Percent Change from 2012 Bridge to MIFRS 2013 Test
Distribution Expenses - Operation	444,089	484,794	40,704	9%
Distribution Expenses - Maintenance	646,529	595,838	28,840	2%
Billing and Collection	695,617	724,206	58,150	5%
Community Relations	5,000	13,000	13,650	273%
Administrative and General Expenses	1,325,663	1,308,463	(17,200)	-1%
Total Operating, Maintenance and Administrative Expenses	3,116,898	3,126,300	9,402	0%
Inflation Rate		2.0%		

Appendix 2-F
OM & A Detailed Costs Table - Port Colborne

OEB Account	Expense Description	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
	Distribution Expenses - Operation							
5005	Operation Supervision and Engineering	38,985	39,034	71,372	47,323	50,514		50,514
5010	Load Dispatching	71,417	88,067	87,701	93,977	94,858		94,858
5012	Station Buildings and Fixtures Expense	20,478	25,914	27,860	27,000	27,917		27,917
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-		-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-		-
5016	Distribution Station Equipment - Operation Labour	17,277	43,634	40,039	17,718	38,033		38,033
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	4,011	317		317
5020	Overhead Distribution Lines and Feeders - Operation Labour	26,248	14,338	38,586	7,412	22,888		22,888
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-	-	-	-	-		-
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-		-
5035	Overhead Distribution Transformers- Operation	-	390	130	6,000	-		-
5040	Underground Distribution Lines and Feeders - Operation Labour	38,808	46,296	65,368	44,669	46,858		46,858
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	-	-	-	-	-		-
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-		-
5055	Underground Distribution Transformers - Operation	2,962	4,108	408	2,969	6,648		6,648
5065	Meter Expense	106,552	119,154	130,482	117,377	123,386		123,386
5070	Customer Premises - Operation Labour	-	-	-	35,666	33,944		33,944
5075	Customer Premises - Materials and Expenses	-	-	-	-	-		-
5085	Miscellaneous Distribution Expense	37,597	26,096	46,062	39,966	44,769	(8,339)	36,430
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-		-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-		-
5096	Other Rent	-	-	-	-	3,000		3,000
	Distribution Expenses - Operation Total	**360,324**	**407,031**	**508,007**	**444,089**	**493,132**	**(8,339)**	**484,794**
	Distribution Expenses - Maintenance							
5105	Maintenance Supervision and Engineering	23,153	45,032	44,489	52,927	46,639		46,639
5110	Maintenance of Buildings and Fixtures - Distribution Stations	17,250	10,253	10,134	13,886	14,365		14,365
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-		-
5114	Maintenance of Distribution Station Equipment	3,355	59,247	30,909	59,988	65,422		65,422
5120	Maintenance of Poles, Towers and Fixtures	13,896	14,869	11,147	26,523	17,503		17,503
5125	Maintenance of Overhead Conductors and Devices	60,500	101,443	110,772	106,945	97,236		97,236
5130	Maintenance of Overhead Services	83,434	77,066	86,314	82,810	79,752		79,752
5135	Overhead Distribution Lines and Feeders - Right of Way	154,760	115,510	92,267	125,333	103,626		103,626
5145	Maintenance of Underground Conduit	-	-	-	-	-		-
5150	Maintenance of Underground Conductors and Devices	2,002	12,333	7,520	15,227	9,818		9,818
5155	Maintenance of Underground Services	4,168	9,589	8,536	19,262	11,216		11,216
5160	Maintenance of Line Transformers	24,028	23,592	24,553	27,341	21,956		21,956
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-		-
5170	Sentinel Lights - Labour	-	-	-	-	-		-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-		-
5175	Maintenance of Meters	56,440	76,429	113,011	112,686	124,704		124,704
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-		-
5195	Maintenance of Other Installations on Customer Premises	-	65	744	3,600	3,600		3,600
	Distribution Expenses - Maintenance Total	**442,988**	**545,428**	**540,395**	**646,529**	**595,838**		**595,838**

	Billing and Collection							
5305	Supervision	25,553	38,455	32,695	46,355	63,002		63,002
5310	Meter Reading Expense	100,131	63,618	28,960	40,547	39,672		39,672
5315	Customer Billing	137,063	148,872	180,176	184,612	189,666		189,666
5320	Collecting	101,157	132,396	138,446	164,774	158,112		158,112
5325	Collecting- Cash Over and Short	-	-	-	-	-		-
5330	Collection Charges	-	-	-	-	-		-
5335	Bad Debt Expense	72,913	2,912	76,247	79,400	92,000		92,000
5340	Miscellaneous Customer Accounts Expenses	139,850	146,902	175,856	179,930	181,754		181,754
	Billing and Collection Total	**576,667**	**533,156**	**632,381**	**695,617**	**724,206**		**724,206**
	Community Relations							
5405	Supervision	-	-	-	-	-		-
5410	Community Relations - Sundry	7,150	3,304	-	-	-		-
5415	Energy Conservation	-	-	-	-	-		-
5420	Community Safety Program	-	-	-	-	5,000		5,000
5425	Miscellaneous Customer Service and Informational Expenses	7,429	6,730	6,901	5,000	8,000		8,000
5505	Supervision	-	-	-	-	-		-
5510	Demonstrating and Selling Expense	-	-	-	-	-		-
5515	Advertising Expense	-	-	-	-	-		-
5660	General Advertising Expenses	-	-	-	-	-		-
	Community Relations Total	**14,579**	**10,034**	**6,901**	**5,000**	**13,000**		**13,000**
	Administrative and General Expenses							
5605	Executive Salaries and Expenses	-	-	-	-	-		-
5610	Management Salaries and Expenses	-	-	-	-	-		-
5615	General Administrative Salaries and Expenses	612,312	685,247	691,629	718,111	725,458		725,458
5620	Office Supplies and Expenses	33,603	33,456	25,536	35,982	28,666		28,666
5625	Administrative Expense Transferred/Credit	(260,729)	(310,797)	(327,671)	(337,250)	(352,293)	352,293	-
5630	Outside Services Employed	51,733	56,169	80,841	60,086	67,932		67,932
5635	Property Insurance	27,025	21,214	19,308	21,100	18,600		18,600
5640	Injuries and Damages	-	224	-	-	-		-
5645	Employee Pensions and Benefits	-	-	-	-	-		-
5650	Franchise Requirements	-	-	-	-	-		-
5655	Regulatory Expenses	229,107	130,579	133,523	130,595	129,067		129,067
5665	Miscellaneous General Expenses	12,734	18,747	7,035	15,000	11,848		11,848
5670	Rent	1,153,211	1,155,108	1,171,108	470,041	119,673		119,673
5675	Maintenance of General Plant	189,143	204,486	184,936	205,368	200,589		200,589
5680	Electrical Safety Authority Fees	-	-	-	-	-		-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-		-
5695	OM&A Contra Account	(1,949)	1,949	-	-	-		-
6205	Donations	-	-	6,629	6,630	6,629		6,629
	Administrative and General Expenses Total	**2,046,190**	**1,996,383**	**1,992,874**	**1,325,663**	**956,170**	**352,293**	**1,308,463**
	Total Operating, Maintenance and Administrative Expenses	**3,440,747**	**3,492,032**	**3,680,558**	**3,116,898**	**2,782,346**	**343,954**	**3,126,300**

Appendix 2-G
OM&A Cost Driver Table
Port Colborne

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Opening Balances	**3,679,224**	**3,440,747**	**3,492,032**	**3,680,558**	**3,116,898**		**3,116,898**
Rent - Port Colborne Lease	**(69,618)**			**(701,066)**	**(350,368)**		**(350,368)**
Bad debt expense		**(70,001)**	**73,335**				
Salaries		**72,935**		**26,482**			
Revised shared cost allocations		**(50,068)**					
Custmer billing			**31,304**				
Meter reading			**(34,658)**				
Customer service supervision			**(5,760)**	**13,659**			
Collecting				**26,329**			
Rate Application	**61,900**	**(98,528)**					
Outside services employed			**24,672**	**(20,755)**			
Distribution maintenance activities	**(102,765)**	**102,440**		**106,134**	**(50,691)**		**(50,691)**
Distribution operating activities	**(50,379)**		**100,976**	**(63,918)**			
GEC						**352,293**	**352,293**
Labour rate change						**(8,339)**	**(8,339)**
Miscellaneous other	**(77,615)**	**94,507**	**(1,343)**	**49,475**	**66,507**		**66,507**
Closing Balances	**3,440,747**	**3,492,032**	**3,680,558**	**3,116,898**	**2,782,346**		**3,126,300**

Appendix 2-I
OM&A Cost per Customer and FTEE - PC

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Changes due to MIFRS	MIFRS 2013 Test
Number of Customers	9,189	9,177	9,144	9,156	9,171	9,191		9,191
Total OM&A from Appendix 2-F	$ 3,679,224	$ 3,440,747	$ 3,492,032	$ 3,680,558	$ 3,116,898	$ 2,782,346	$ 343,954	$ 3,126,300
OM&A cost per Customer	$ 400	$ 375	$ 382	$ 402	$ 340	$ 303		$ 340
Number of FTEEs	20.66	20.66	18.58	18.58	20.79	20.79		20.79
FTEEs/Customer	0.0022	0.0023	0.0020	0.0020	0.0023	0.0023		0.0023
OM&A cost per FTEE	$ 178,084	$ 166,541	$ 187,946	$ 198,092	$ 149,923	$ 133,831		$ 150,375

The number of FTEEs is based on the methodology described in the. BDR report.

OM & A Detailed Costs Table
Port Colborne

OEB Account	Expense Description	Variance from 2007 Actual	2009 Board Approved	2009 Actual	Variance from 2009 EDR	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge	Variance from 2011 Actual	2013 Test	Variance from 2012 Bridge	Changes due to MIFRS	MIFRS 2013 Test
	Distribution Expenses - Operation														
5005	Operation Supervision and Engineering	(1,948)	33,780	38,985	5,205	39,034	49	71,372	32,338	47,323	(24,049)	50,514	3,191		50,514
5010	Load Dispatching	(17,888)	78,120	71,417	(6,703)	88,067	16,650	87,701	(366)	93,977	6,276	94,858	880		94,858
5012	Station Buildings and Fixtures Expense	(10,409)	30,000	20,478	(9,522)	25,914	5,437	27,860	1,945	27,000	(860)	27,917	917		27,917
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-	-		-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5016	Distribution Station Equipment - Operation Labour	(48,603)	39,765	17,277	(22,488)	43,634	26,357	40,039	(3,595)	17,718	(22,321)	38,033	20,315		38,033
5017	Distribution Station Equipment - Operation Supplies and Expenses	130	-	-	-	-	-	-	-	4,011	4,011	317	(3,694)		317
5020	Overhead Distribution Lines and Feeders - Operation Labour	(279)	-	26,248	26,248	14,338	(11,910)	38,586	24,248	7,412	(31,174)	22,888	15,476		22,888
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-		-
5035	Overhead Distribution Transformers- Operation	340	-	-	-	390	390	130	(260)	6,000	5,870	-	(6,000)		-
5040	Underground Distribution Lines and Feeders - Operation Labour	20,138	47,568	38,808	(8,760)	46,296	7,488	65,368	19,072	44,669	(20,699)	46,858	2,189		46,858
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	-	-	-	-	-	-	-	-	-	-	-	-		-
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-		-
5055	Underground Distribution Transformers - Operation	5,490	-	2,962	2,962	4,108	1,146	408	(3,700)	2,969	2,561	6,648	3,679		6,648
5065	Meter Expense	(20,227)	123,887	106,552	(17,335)	119,154	12,602	130,482	11,328	117,377	(13,105)	123,386	6,009		123,386
5070	Customer Premises - Operation Labour	-	6,000	-	(6,000)	-	-	-	-	35,666	35,666	33,944	(1,722)		33,944
5075	Customer Premises - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5085	Miscellaneous Distribution Expense	(32,278)	51,582	37,597	(13,985)	26,096	(11,500)	46,062	19,965	39,966	(6,096)	44,769	4,803	(8,339)	36,430
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-		-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-		-
5096	Other Rent	120	-	-	-	-	-	-	-	-	-	3,000	3,000		3,000
	Distribution Expenses - Operation Total	**(105,415)**	**410,703**	**360,324**	**(50,379)**	**407,031**	**46,707**	**508,007**	**100,976**	**444,089**	**(63,918)**	**493,132**	**49,043**	**(8,339)**	**484,794**
	Distribution Expenses - Maintenance														
5105	Maintenance Supervision and Engineering	(8,204)	15,267	23,153	7,886	45,032	21,879	44,489	(543)	52,927	8,438	46,639	(6,288)		46,639
5110	Maintenance of Buildings and Fixtures - Distribution Stations	1,607	2,016	17,250	15,234	10,253	(6,997)	10,134	(119)	13,886	3,752	14,365	480		14,365
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-		-
5114	Maintenance of Distribution Station Equipment	(36,389)	6,000	3,355	(2,645)	59,247	55,891	30,909	(28,338)	59,988	29,079	65,422	5,434		65,422
5120	Maintenance of Poles, Towers and Fixtures	(28,302)	38,886	13,896	(24,990)	14,869	973	11,147	(3,722)	26,523	15,376	17,503	(9,019)		17,503
5125	Maintenance of Overhead Conductors and Devices	(6,179)	96,414	60,500	(35,914)	101,443	40,943	110,772	9,329	106,945	(3,827)	97,236	(9,710)		97,236
5130	Maintenance of Overhead Services	(6,863)	102,414	83,434	(18,980)	77,066	(6,368)	86,314	9,248	82,810	(3,503)	79,752	(3,058)		79,752
5135	Overhead Distribution Lines and Feeders - Right of Way	(32,114)	128,046	154,760	26,714	115,510	(39,250)	92,267	(23,243)	125,333	33,066	103,626	(21,707)		103,626
5145	Maintenance of Underground Conduit	-	-	-	-	-	-	-	-	-	-	-	-		-
5150	Maintenance of Underground Conductors and Devices	8,549	23,715	2,002	(21,713)	12,333	10,330	7,520	(4,813)	15,227	7,708	9,818	(5,409)		9,818
5155	Maintenance of Underground Services	(5,585)	30,417	4,168	(26,250)	9,589	5,421	8,536	(1,053)	19,262	10,727	11,216	(8,046)		11,216
5160	Maintenance of Line Transformers	1,289	23,715	24,028	313	23,592	(436)	24,553	960	27,341	2,789	21,956	(5,385)		21,956
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-		-
5170	Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-		-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5175	Maintenance of Meters	25,615	78,862	56,440	(22,422)	76,429	19,989	113,011	36,582	112,686	(325)	124,704	12,018		124,704
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-	-	-	-		-
5195	Maintenance of Other Installations on Customer Premises	776	-	-	-	65	65	744	679	3,600	2,856	3,600	-		3,600
	Distribution Expenses - Maintenance Total	**(85,801)**	**545,753**	**442,988**	**(102,765)**	**545,428**	**102,440**	**540,395**	**(5,033)**	**646,529**	**106,134**	**595,838**	**(50,691)**	**-**	**595,838**
	Billing and Collection														
5305	Supervision	(8,188)	58,046	25,553	(32,493)	38,455	12,902	32,695	(5,760)	46,355	13,659	63,002	16,648		63,002
5310	Meter Reading Expense	1,686	98,433	100,131	1,698	63,618	(36,513)	28,960	(34,658)	40,547	11,586	39,672	(875)		39,672
5315	Customer Billing	13,754	157,661	137,063	(20,598)	148,872	11,809	180,176	31,304	184,612	4,436	189,666	5,054		189,666
5320	Collecting	(5,499)	103,910	101,157	(2,754)	132,396	31,239	138,446	6,049	164,774	26,329	158,112	(6,662)		158,112
5325	Collecting- Cash Over and Short	-	-	-	-	-	-	-	-	-	-	-	-		-
5330	Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-		-
5335	Bad Debt Expense	(17,662)	65,945	72,913	6,968	2,912	(70,001)	76,247	73,335	79,400	3,153	92,000	12,600		92,000
5340	Miscellaneous Customer Accounts Expenses	(16,279)	128,523	139,850	11,327	146,902	7,052	175,856	28,955	179,930	4,073	181,754	1,824		181,754
	Billing and Collection Total	**(32,188)**	**612,519**	**576,667**	**(35,852)**	**533,156**	**(43,511)**	**632,381**	**99,225**	**695,617**	**63,236**	**724,206**	**28,589**	**-**	**724,206**

	Community Relations														
5405	Supervision	-	-	-	-	-	-	-	-	-	-	-	-		-
5410	Community Relations - Sundry	5,250	10,532	7,150	(3,382)	3,304	(3,846)	-	(3,304)	-	-	-	-		-
5415	Energy Conservation	-	-	-	-	-	-	-	-	-	-	-	-		-
5420	Community Safety Program	(1,847)	2,500	-	(2,500)	-	-	-	-	-	-	5,000	5,000		5,000
5425	Miscellaneous Customer Service and Informational Expenses	5,603	10,666	7,429	(3,237)	6,730	(699)	6,901	172	5,000	(1,901)	8,000	3,000		8,000
5505	Supervision	-	-	-	-	-	-	-	-	-	-	-	-		-
5510	Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-		-
5515	Advertising Expense	-	-	-	-	-	-	-	-	-	-	-	-		-
5660	General Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
	Community Relations Total	**9,006**	**23,698**	**14,579**	**(9,119)**	**10,034**	**(4,545)**	**6,901**	**(3,132)**	**5,000**	**(1,901)**	**13,000**	**8,000**	**-**	**13,000**
	Administrative and General Expenses														
5605	Executive Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5610	Management Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-		-
5615	General Administrative Salaries and Expenses	62,383	619,072	612,312	(6,760)	685,247	72,935	691,629	6,382	718,111	26,482	725,458	7,347		725,458
5620	Office Supplies and Expenses	(9,380)	41,976	33,603	(8,373)	33,456	(148)	25,536	(7,920)	35,982	10,447	28,666	(7,317)		28,666
5625	Administrative Expense Transferred/Credit	(8,856)	(260,729)	(260,729)	-	(310,797)	(50,068)	(327,671)	(16,874)	(337,250)	(9,579)	(352,293)	(15,043)	352,293	-
5630	Outside Services Employed	10,310	49,384	51,733	2,349	56,169	4,437	80,841	24,672	60,086	(20,755)	67,932	7,846		67,932
5635	Property Insurance	(6,210)	55,000	27,025	(27,975)	21,214	(5,810)	19,308	(1,906)	21,100	1,792	18,600	(2,500)		18,600
5640	Injuries and Damages	-	-	-	-	224	224	-	(224)	-	-	-	-		-
5645	Employee Pensions and Benefits	(99,251)	700	-	(700)	-	-	-	-	-	-	-	-		-
5650	Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-	-		-
5655	Regulatory Expenses	(6,951)	167,207	229,107	61,900	130,579	(98,528)	133,523	2,944	130,595	(2,928)	129,067	(1,528)		129,067
5665	Miscellaneous General Expenses	-	-	12,734	12,734	18,747	6,013	7,035	(11,712)	15,000	7,965	11,848	(3,151)		11,848
5670	Rent	########	1,222,829	1,153,211	(69,618)	1,155,108	1,897	1,171,108	15,999	470,041	(701,066)	119,673	(350,368)		119,673
5675	Maintenance of General Plant	37,200	191,112	189,143	(1,969)	204,486	15,343	184,936	(19,550)	205,368	20,432	200,589	(4,779)		200,589
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-	-	-	-	-	-		-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-		-
5695	OM&A Contra Account	-	-	(1,949)	(1,949)	1,949	3,899	-	(1,949)	-	-	-	-		-
6205	Donations	-	-	-	-	-	-	6,629	6,629	6,630	1	6,629	(1)		6,629
	Administrative and General Expenses Total	**(192,613)**	**2,086,552**	**2,046,190**	**(40,362)**	**1,996,383**	**(49,807)**	**1,992,874**	**(3,509)**	**1,325,663**	**(667,210)**	**956,170**	**(369,493)**	**352,293**	**1,308,463**
	Taxes Other Than Income Taxes														
6105	Taxes Other Than Income Taxes (Note less capital taxes)	27	70,000	53,880	(16,120)	52,557	(1,323)	52,024	(533)	55,000	2,976	54,100	(900)		54,100
	Taxes Total	**27**	**70,000**	**53,880**	**(16,120)**	**52,557**	**(1,323)**	**52,024**	**(533)**	**55,000**	**2,976**	**54,100**	**(900)**	**-**	**54,100**
	Total Operating, Maintenance and Administrative Expenses	**(406,984)**	**3,749,224**	**3,494,628**	**(254,596)**	**3,544,589**	**49,961**	**3,732,582**	**187,993**	**3,171,898**	**(560,684)**	**2,836,446**	**(335,452)**	**343,954**	**3,180,400**
	Power Supply Expenses														
4705	Power Purchased	42,089	11,294,350	11,660,603	366,253	13,015,882	1,355,279	14,508,044	1,492,163	15,746,478	1,238,434	14,036,403	(1,710,075)		14,036,403
4708	Charges-WMS	27,234	1,232,393	1,233,978	1,585	1,289,523	55,546	1,376,501	86,977	1,342,015	(34,486)	1,169,833	(172,182)		1,169,833
4710	Cost of Power Adjustments	-	-	-	-	-	-	-	-	-	-	-	-		-
4712	Charges-One-Time	-	-	-	-	-	-	-	-	-	-	-	-		-
4714	Charges-NW	(94,073)	951,737	869,901	(81,835)	1,021,545	151,644	1,126,558	105,012	1,240,466	113,908	1,299,672	59,205		1,299,672
4716	Charges-CN	23,051	886,093	837,623	(48,470)	905,397	67,774	982,659	77,262	1,064,925	82,266	1,047,004	(17,921)		1,047,004
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-	-	-	-	-		-
4750	Charges - LV	62,058	20,783	25,380	4,597	8,126	(17,254)	20,979	12,853	20,989	10	20,979	(10)		20,979
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-		-
	Power Supply Expenses Total	**60,360**	**14,385,356**	**14,627,485**	**242,129**	**16,240,473**	**1,612,988**	**18,014,740**	**1,774,268**	**19,414,874**	**1,400,133**	**17,573,891**	**(1,840,983)**	**-**	**17,573,891**
	Total Expenses for Working Capital	**(346,624)**	**18,134,580**	**18,122,113**	**(12,468)**	**19,785,062**	**1,662,949**	**21,747,322**	**1,962,260**	**22,586,771**	**839,449**	**20,410,337**	**(2,176,434)**	**343,954**	**20,754,291**
	Amortization Expenses														
5705	Amortization Expense - Property, Plant, and Equipment	27,229	640,028	421,526	(218,502)	670,717	249,190	126,786	(543,931)	1,056,807	930,022	1,426,900	370,093	(165,726)	1,261,174
5715	Amortization of Intangibles and Other Electric Plant	-	-	-	-	-	-	-	-	-	-	-	-		-
	Amortization Expenses Total	**27,229**	**640,028**	**421,526**	**(218,502)**	**670,717**	**249,190**	**126,786**	**(543,931)**	**1,056,807**	**930,022**	**1,426,900**	**370,093**	**(165,726)**	**1,261,174**
	Grand Total	**(319,396)**	**18,774,608**	**18,543,639**	**(230,969)**	**20,455,779**	**1,912,140**	**21,874,108**	**1,418,329**	**23,643,579**	**1,769,471**	**21,837,237**	**(1,806,342)**	**178,228**	**22,015,466**

TAX CALCULATIONS - Port Colborne

Description	TOTAL CNPI 2009 Actual	TRANSMISSION 2009 Actual	DISTRIBUTION 2009 Actual	TOTAL CNPI 2010 Actual	TRANSMISSION 2010 Actual	DISTRIBUTION 2010 Actual	TOTAL CNPI 2011 Forecast	TRANSMISSION 2011 Forecast	DISTRIBUTION 2011 Forecast	TOTAL CNPI 2012 Regulatory	TRANSMISSION 2012 Forecast	DISTRIBUTION 2012 Regulatory	TOTAL CNPI 2013 Regulatory	TRANSMISSION 2013 Forecast	DISTRIBUTION 2013 Regulatory	Changes due to MIFRS	MIFRS DISTRIBUTION 2013 Regulatory
Net income(loss) per financial statements	3,024,635	1,323,074	1,701,561	3,121,711	1,504,497	1,617,214	3,005,857	1,555,846	1,450,011	-	-	-	-	-	-		-
Utility income before taxes	-	-	-	-	-	-	-	-	-	3,450,067	1,236,000	2,214,067	3,893,068	1,215,000	2,678,068	1,841	2,679,909
Add:																	
Provision for income taxes - current	878,461	395,534	482,927	573,810	275,206	298,604	188,737	100,033	88,704	-	-	-	-	-	-		-
Amortization of assets	4,075,289	756,056	3,319,233	4,262,383	762,455	3,499,928	4,452,997	765,727	3,687,270	5,363,652	884,000	4,479,652	6,069,339	901,000	5,168,339	(881,820)	4,286,519
SHRED	64,716	-	64,716	-	-	-	-	-	-	-	-	-	-	-	-		-
Donations	27,100	2,389	24,711	-	-	-	-	-	-	-	-	-	-	-	-		-
Non-deductible meals and entertainment	17,858	1,574	16,284	19,228	2,523	16,705	19,000	2,493	16,507	19,000	2,493	16,507	19,000	2,493	16,507		16,507
Reserves from financial statements - EOY	2,357,583	207,811	2,149,772	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918	1,676,000	219,924	1,456,076		1,456,076
Amortization of deferred financing	32,028	12,798	19,230	32,028	10,776	21,252	32,028	7,393	24,635	32,028	7,299	24,729	32,028	7,212	24,816		24,816
Amortization of deferred lease costs	58,140	-	58,140	58,140	-	58,140	58,140	-	58,140	19,380	-	19,380	-	-	-		-
Ontario apprentice and co-op tax credits	4,333	382	3,951	11,274	1,479	9,795	4,000	525	3,475	4,000	525	3,475	4,000	525	3,475		3,475
Total Additions	7,515,508	1,376,544	6,138,964	7,115,278	1,335,665	5,779,613	6,609,902	1,119,583	5,490,319	7,260,060	1,133,399	6,126,661	7,800,367	1,131,153	6,669,213	(881,820)	5,787,393
Deduct:																	
Gain on disposal of assets per financial statements	51,467	-	51,467	37,802	-	37,802	25,266	-	25,266	-	-	-	-	-	-		-
Capital cost allowance	4,178,748	554,313	3,624,435	5,102,785	538,668	4,564,117	5,592,886	524,476	5,068,410	5,672,863	680,078	4,992,785	5,960,047	861,745	5,098,302		5,098,302
Cumulative eligible capital deduction	7,781	(0)	7,781	7,237	-	7,237	6,730	-	6,730	6,259	-	6,259	6,259	-	6,259		6,259
Reserves from financial statements - BOY	2,386,859	210,392	2,176,467	2,357,583	309,361	2,048,222	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918		1,582,918
Allowance for funds used during construction	116,308	116,308	-	16,338	16,338	-	-	-	-	-	-	-	-	-	-		-
Capitalized general expense	1,015,195	-	1,015,195	970,154	-	970,154	980,256	-	980,256	1,069,910	-	1,069,910	1,112,726	-	1,112,726	(1,112,726)	(0)
Total Deductions	7,756,358	881,013	6,875,345	8,491,899	864,366	7,627,532	8,763,553	807,702	7,955,851	8,604,032	923,489	7,680,542	8,901,032	1,100,827	7,800,205	(1,112,726)	6,687,479
Taxable Income	2,783,785	1,818,605	965,180	1,745,090	1,975,796	(230,706)	852,206	1,867,727	(1,015,521)	2,106,095	1,445,909	660,186	2,792,403	1,245,327	1,547,076	232,747	1,779,823
Corporate tax rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	739,987	330,012	409,975	61,678	471,653
Grossed Up Taxes															557,789	83,916	641,705
Calculation of total taxes																	
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	887,801	330,012	557,789	83,916	641,705
Ontario apprentice and co-op tax credits	-	-	-	(9,416)	(1,236)	(8,180)	-	-	-	-	-	-	-	-	-		-
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777	-	-	-	-	-	-	-	-	-		-
Total taxes	**1,136,360**	**687,131**	**449,229**	**600,550**	**634,472**	**(33,922)**	**240,748**	**527,633**	**(286,885)**	**558,115**	**383,166**	**174,949**	**887,801**	**330,012**	**557,789**	**83,916**	**641,705**
Tax Rates																	
Federal Tax	19.00%	19.00%	19.00%	18.00%	18.00%	18.00%	16.50%	16.50%	16.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%		15.00%
Provincial Tax	14.00%	14.00%	14.00%	13.00%	13.00%	13.00%	11.75%	11.75%	11.75%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%		11.50%
Total Tax Rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%		26.50%
Calculation of Ontario Capital Tax																	
Net Paid Up Capital	99,498,319	39,756,937	59,741,382	95,514,739	32,135,669	63,379,070											
Less Exemption	2,738,073	1,094,063	1,644,010	2,768,091	931,317	1,836,774											
Taxable Capital/Deemed Taxable Capital	96,760,246	38,662,874	58,097,372	92,746,648	31,204,352	61,542,296											
OCT Rate	0.225%	0.225%	0.225%	0.074%	0.074%	0.074%											
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777											
PORT COLBORNE RATE BASE			14,140,589			15,731,210			16,413,517			18,609,841			20,731,676	(52,102)	20,679,574
% OF TOTAL RATE BASE			24%			25%			25%			27%			28%		28%
TOTAL TAXES			**106,331**			**(8,420)**			**(72,500)**			**47,115**			**157,521**	**23,118**	**180,639**

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

26. Ref: E 4/T1/S1/p.1

Please provide an update of CNPI's – FE/EOP Operating Costs, year-to-date expenses in the same detail as shown in on the table on page 1 (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administrative and General and Total OM&A Expenses). Also, please provide the figures for the corresponding period in 2010.

RESPONSE:

Total Operations, Maintenance, and Administrative Expenses - FE and EOP

Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Actual June 30, 2011	Actual June 30, 2012
Operating	1,092,166	780,256	930,665	974,144	972,350	942,827	483,739	529,579
Maintenance	1,176,848	1,017,747	1,119,821	1,287,101	1,287,800	1,316,640	548,105	694,628
Billing and Collection	1,215,240	1,153,666	1,266,553	1,255,007	1,278,697	1,336,847	631,519	589,576
Community Relations	47,830	26,301	27,566	13,138	14,050	27,700	-	4,145
Administrative and General	2,127,042	1,728,030	2,102,573	1,881,227	2,059,275	2,221,587	998,994	924,778
Taxes Other than Income Taxes	59,000	63,737	35,376	60,149	55,500	62,600	29,882	30,072
	5,718,126	4,769,738	5,482,553	5,470,766	5,667,671	5,908,201	2,692,238	2,772,778

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

27. Ref: E4/T2/S5/p.1 and E3/T2/S2/p.11, Table 7

The table provided on page 1 of the first reference does not match the customer numbers forecast in table 7 of the second reference. Please reconcile the two tables and update the evidence if necessary.

RESPONSE:

The table provided on page 1 of the first reference, E4/T2/S5/p.1, provides different information than does Table 7 of the second reference E3/T2/S2/p.11. The first reference, E4/T2/S5/p.1, is based on the year end customer count or connections. The second reference, E3/T2/S2/p.11, is the average number of customers or connections, dependent upon which is the billing determinant, for the year. This is the forecasted number of customers/connections used to calculate the revenue from rates.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

28. Ref: E4/T2/S5/p.1, Appendix 2-l – OM&A cost per customer – FE/EOP

Appendix 2-l shows CNPI – FE/EOP's OM&A cost per customer to be $300 in the 2013 Test Year, up from the $293 for 2009 Board Approved, but more significantly up from $246 for 2009 actual.

a) Board staff notes that the customer numbers on Appendix 2-l does not match the proposed customer numbers in Exhibit 3. Please reconcile the two and update the evidence if necessary.
b) Please elaborate on how CNPI – FE/EOP's OM&A per customer compares to its peer group.

RESPONSE:

a) Please refer to Board Staff Interrogatory No. 27.

b) To the best of the Company's knowledge, the only source of summarized statistical data on the OM&A costs per customer of all Ontario LDCs is the LDC statistical data published annually by the Board. The most recent year of data currently available is 2010, and is available from the Board at

http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors

Based on this data, FE/EOP's 2010 OM&A cost of $284 per customer was in line with the industry average of $282 per customer.

If it is assumed that all other LDCs in the province increase their OM&A cost per customer by at least 2% annually between 2010 and 2013, FE/EOP's

2013 forecast cost of $300 per customer would be in line with the industry average of $299 per customer.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

29. E4/T2/S2/Appendix 2-F

a) Please provide the increase in OM&A expenses between 2011 and 2013 that are due solely to the transition to MIFRS.

RESPONSE:

a)

OM & A Variance Analysis - FE and EOP

OEB Account	Expense Description	2011 Actual	2013 Test	MIFRS 2013 Test	2013 Test Versus 2011		2013 Test Versus MIFRS 2013 Test	
					Variance $	Percentage	Variance $	Percentage
	Distribution Expenses - Operation							
5005	Operation Supervision and Engineering	101,285	100,859	100,859	(426)	0%	-	0%
5010	Load Dispatching	155,499	164,182	164,182	8,683	6%	-	0%
5012	Station Buildings and Fixtures Expense	130,309	118,200	118,200	(12,109)	-9%	-	0%
5016	Distribution Station Equipment - Operation Labour	74,945	50,764	50,764	(24,181)	-32%	-	0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	10,719	13,920	13,920	3,201	30%	-	0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	53,193	50,180	50,180	(3,013)	-6%	-	0%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	15,027	15,720	15,720	693	5%	-	0%
5035	Overhead Distribution Transformers- Operation	1,163	1,580	1,580	417	36%	-	0%
5040	Underground Distribution Lines and Feeders - Operation Labour	99,047	116,706	116,706	17,660	18%	-	0%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	1,012	1,600	1,600	588	58%	-	0%
5055	Underground Distribution Transformers - Operation	-	1,519	1,519	1,519	100%	-	0%
5065	Meter Expense	223,222	201,118	201,118	(22,104)	-10%	-	0%
5070	Customer Premises - Operation Labour	238	13,722	13,722	13,484	5666%	-	0%
5075	Customer Premises - Materials and Expenses	-	6,000	6,000	6,000	100%	-	0%
5085	Miscellaneous Distribution Expense	108,171	86,756	123,682	(21,415)	-20%	36,927	43%
5090	Underground Distribution Lines and Feeders - Rental Paid	315	-	-	(315)	-100%	-	0%
	Distribution Expenses - Operation Total	**974,144**	**942,827**	**979,754**	**(31,316)**	-3%	**36,927**	4%
	Distribution Expenses - Maintenance							
5105	Maintenance Supervision and Engineering	69,536	51,543	51,543	(17,993)	-26%	-	0%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	26,554	22,841	22,841	(3,712)	-14%	-	0%
5114	Maintenance of Distribution Station Equipment	72,501	86,811	86,811	14,310	20%	-	0%
5120	Maintenance of Poles, Towers and Fixtures	45,547	44,170	44,170	(1,377)	-3%	-	0%
5125	Maintenance of Overhead Conductors and Devices	173,016	186,962	186,962	13,946	8%	-	0%
5130	Maintenance of Overhead Services	215,665	192,082	192,082	(23,583)	-11%	-	0%
5135	Overhead Distribution Lines and Feeders - Right of Way	314,480	339,364	339,364	24,884	8%	-	0%
5145	Maintenance of Underground Conduit	606	-	-	(606)	-100%	-	0%
5150	Maintenance of Underground Conductors and Devices	27,101	30,022	30,022	2,921	11%	-	0%
5155	Maintenance of Underground Services	44,016	33,877	33,877	(10,140)	-23%	-	0%
5160	Maintenance of Line Transformers	94,589	73,185	73,185	(21,404)	-23%	-	0%
5175	Maintenance of Meters	203,490	255,783	255,783	52,293	26%	-	0%
	Distribution Expenses - Maintenance Total	**1,287,101**	**1,316,640**	**1,316,640**	**29,539**	2%	**-**	0%
	Billing and Collection							
5305	Supervision	78,088	104,555	104,555	26,466	34%	-	0%
5310	Meter Reading Expense	40,740	53,354	53,354	12,614	31%	-	0%
5315	Customer Billing	318,957	366,923	366,923	47,966	15%	-	0%
5320	Collecting	213,400	252,724	252,724	39,324	18%	-	0%
5335	Bad Debt Expense	145,410	160,000	160,000	14,590	10%	-	0%
5340	Miscellaneous Customer Accounts Expenses	458,413	399,291	399,291	(59,122)	-13%	-	0%
	Billing and Collection Total	**1,255,007**	**1,336,847**	**1,336,847**	**81,840**	7%	**-**	0%
	Community Relations							
5410	Community Relations - Sundry	750	-	-	(750)	-100%	-	0%
5420	Community Safety Program	-	4,200	4,200	4,200	100%	-	0%
5425	Miscellaneous Customer Service and Informational Expenses	10,168	18,500	18,500	8,332	82%	-	0%
5660	General Advertising Expenses	2,220	5,000	5,000	2,780	125%	-	0%
	Community Relations Total	**13,138**	**27,700**	**27,700**	**14,562**	111%	**-**	0%
	Administrative and General Expenses							
5615	General Administrative Salaries and Expenses	3,177,159	3,947,271	3,947,271	770,113	24%	-	0%
5620	Office Supplies and Expenses	372,791	521,137	521,137	148,346	40%	-	0%
5625	Administrative Expense Transferred/Credit	(4,222,883)	(5,475,410)	(4,714,977)	(1,252,527)	30%	760,433	-14%
5630	Outside Services Employed	304,875	392,764	392,764	87,890	29%	-	0%
5635	Property Insurance	39,824	39,400	39,400	(424)	-1%	-	0%
5645	Employee Pensions and Benefits	866,151	1,189,718	1,189,718	323,568	37%	-	0%
5655	Regulatory Expenses	163,234	191,623	191,623	28,389	17%	-	0%
5665	Miscellaneous General Expenses	65,527	165,397	165,397	99,870	152%	-	0%
5670	Rent	254,049	223,037	223,037	(31,012)	-12%	-	0%
5675	Maintenance of General Plant	846,033	1,012,179	1,012,179	166,146	20%	-	0%
6205	Donations	14,469	14,470	14,470	1	0%	-	0%
	Administrative and General Expenses Total	**1,881,227**	**2,221,587**	**2,982,020**	**340,359**	18%	**760,433**	34%
	Total Operating, Maintenance and Administrative Expenses	**5,410,617**	**5,845,601**	**6,642,960**	**434,984**	8%	**797,360**	14%

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

30. Ref: E4/T2/S2/Appendix 2-F and E10/T1/S1/p.1 - RRWF

On page 1 of E10/T1/S1/p.1 CNPI requests approval to include Smart Meter OM&A costs for 2013 into the 2013 Revenue Requirement Work Form.

a) Please provide the increase in OM&A in 2013 as compared to 2011 due to smart meter OM&A.
b) Please confirm whether or not CNPI included any revenue from the Smart meter funding adder in the Distribution Revenue of $10,830,301 (Distribution Revenue at Current Rates) as shown in the RRWF. If so, what is the amount and please re-run RRWF for 2013 excluding the Smart Meter rate adder from the calculation.

c)

RESPONSE:

a) In 2011, OEB 5065 had $2,787 related to Smart Meter OM&A and for 2013, OEB 5065 has $18,154 budgeted. Additionally, in 2011, OEB 5175 had $92,321 related to Smart Meter OM&A and for 2013, OEB 5175 has $169,964 budgeted.

b) CNPI confirms that any revenue from the Smart Meter funding adder was not included in the Distribution Revenue of $10,830,301.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

31. Ref: E4/T2/S2 Appendix 2-E and Appendix 2-F – Summary of Operating Expenses – FE/EOP

Appendix 2-F shows that under Maintenance, the Maintenance of Meters grows from $203,490 in 2011, to $228,910 in 2012 and to $255,783 in the test year. Why is this expense increasing at this pace, even as CNPI has essentially completed its Smart Meter deployment?

RESPONSE:

The maintenance of meters account includes maintenance for O&M for AMI and ODS services. CNPI has Smart Meter maintenance agreements with third parties for AMI and ODS services, and these agreements have both fixed and variable components. As CNPI installed more of its Smart Meters, the variable component of these maintenance agreements increased; thus increasing the overall maintenance agreement costs year-to-year. Given that 100% of Smart Meter installations for both Residential and GS<50 rate categories did not occur until Q1 2012, 2013 will be the first full year that both the fixed and variable components of the maintenance agreements will be incurred.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

32. Ref: E4/T2/S2 Appendix 2-F

CNPI shows a decrease in Miscellaneous Customer Service and Informational Expenses from $8,945 in 2009 to $7,621 in 2010 with increases following in 2011 to $10,168, $9,400 in 2012 and $18,500 in 2013. Please provide further explanation for these expenses, in particular how labour is allocated to this account.

RESPONSE:

These expenses are primarily comprised of the cost of the annual customer satisfaction survey. 2009 and 2010 were the only years that labour was allocated to this account and the amounts were $2,487 and $1,484 respectively. In 2013, $7,000 was allocated to account 5425 and should have been allocated to account 5420 (Community Safety Program) to fund the School Safety Program, which is run on a four year cycle.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

33. E4/T3/S2/p.1 and E4/T3/S1/p.1 – Operation

In the detailed OM&A Cost Table CNPI shows a decrease of 28.55% in total Distribution Operations cost from 2009 Board-approved to 2009 actual. Board staff notes that in the variance analysis CNPI describes a re-allocation of labour to accounts 5016, 5065 and 5085. Please provide detailed explanations as to these decreases and describe the labour re-allocation in detail.

RESPONSE:

For OEB Account 5016 (Distribution Station Equipment – Operation Labour), 2009 Actual costs were less than 2009 Board Approved by $138,000. This occurred mainly because in 2009 Fort Erie-based Substation Electricians were reassigned to three major projects – the construction and commissioning of Sherkston DS in Port Colborne, the Mobile Transformer Refurbishment in Port Colborne, and the completion of decommissioning activities at the Rankine Generating Plant. Substation Electrician labour allocations to these projects in 2009 were as follows:

Sherkston DS:	$119,000
Mobile Transformer:	$ 60,000
Rankine decommissioning:	$ 31,000

For OEB Account 5065 (Meter Expenses), 2009 Actual costs were less than 2009 Board Approved by $30,700. This occurred primarily because the Metering

Supervisor spent significant time on the Grimsby Power Inc. SAP Migration Project, resulting in reduced allocations to Account 5065 in 2009.

For OEB Account 5085 (Miscellaneous Distribution Expense), 2009 Actual costs were less than 2009 Board Approved by $101,830. This occurred primarily because of a concerted internal effort to allocate costs to more appropriate accounts rather than using the “Miscellaneous” account. The overall reduction was comprised of a $66,492 decrease in Fort Erie and a $35,338 decrease in EOP. Costs in this account remained fairly consistent for the period 2009 Actual to 2013 Test Year.

The foregoing reductions were the primary causes of the 28.55% decrease in cumulative Distribution Operation expenses from 2009 Board Approved to 2009 Actual.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

34. E4/T3/S2/p.2 and E4/T3/S1/p.1 – Maintenance

In the detailed OM&A Cost Table CNPI shows a decrease of 13.5% in total Distribution Maintenance cost from 2009 Board-approved to 2009 actual and a subsequent increase of 29% increase in the 2013 test year over 2009 actual. Please explain the decrease in 2009 actual from 2009 Board-approved and provide a more detailed trend analysis from 2009 Board approved and actual to the forecast for 2013..

RESPONSE:

The decrease from 2009 Board Approved to 2009 Actual occurred primarily because costs in OEB Accounts 5150 (Maintenance of Underground Conductors and Devices) and 5155 (Maintenance of Underground Services) were lower than anticipated. In total, 2009 Actual costs for these two accounts were $115,280 less than 2009 Board Approved, reflecting lower than anticipated reactive maintenance in Fort Erie.

Total Distribution Maintenance costs increased by 10.02% from 2009 Actual to 2010 Actual, primarily because of increases in substation and line maintenance activity in 2010, following decreases in such activity in 2009. Expenditures in Maintenance Supervision and Engineering also increased compared to 2009 because of increased oversight of maintenance programs in Fort Erie.

Total Distribution Maintenance costs increased by 14.94% from 2010 Actual to 2011 Actual. This was due primarily to increased Meter Maintenance (OEB Account 5175) costs in Fort Erie and EOP in 2011, resulting in an increase of

$98,696 over 2010 Actual. This increase occurred mainly for two reasons. First, due to Smart Meter deployment Meter Technicians in Fort Erie and EOP spent an increased amount of time on activities such as troubleshooting meter communication issues and performing meter checks in response to "high bill" complaints. These labour increases accounted for approximately $40,000 of the variance. Secondly, as the Smart Meter networks in Fort Erie and EOP expanded, increased costs were incurred in 2011 in the form of vendor fees for maintenance of the AMI network and the ODS. Increases in these fees accounted for approximately $45,000 of the Meter Maintenance cost variance. In addition to increases in Meter Maintenance, increases were also incurred in Maintenance Supervision and Engineering due to increased emphasis on maintenance programs. Increases were also incurred in Maintenance of Underground Services, due to an increase in reactive maintenance activity.

Total Distribution Maintenance costs are anticipated to increase by 0.05% from 2011 Actual to 2012 Bridge Year, while an increase of 2.2% is expected from 2012 Bridge to 2013 Test Year.

When 2009 Board Approved total Distribution Maintenance costs are compared with those forecasted for the 2013 Test Year, the anticipated 2013 Test Year costs are 11.88% above 2009 Board Approved, representing a modest increase over the five-year period. This is a more pertinent comparison than the comparison with 2009 Actual, because of the decreases in 2009 Actual expenditures that were explained earlier. Specific accounts where costs increased from 2009 Board Approved to the 2013 Test Year forecast are associated with the following: incremental costs associated with the operation and maintenance of a new Smart Meter network; increased station maintenance activity that is anticipated as stations age; and increased costs in Maintenance Supervision and Engineering, reflecting increased oversight of maintenance

programs. However, increases in Station maintenance and Maintenance Supervision are approximately offset by decreases in underground plant maintenance. The incremental Smart Meter network costs amount to approximately $125,000, which is comparable to the increase of $139,792 in total Distribution Maintenance costs from 2009 Board Approved to 2013 Test Year.

Costs in individual accounts can fluctuate from year to year, depending on system needs, priorities, or the amount of reactive maintenance required. When Smart Meter network costs are excluded from the analysis, 2013 Test Year forecast costs are only 0.41% above 2009 Board Approved expenditures. This demonstrates that total Distribution Maintenance costs for traditional activities have remained level over the five-year period from 2009 Board Approved to 2013 Test Year. The net cost increase from 2009 Board Approved to 2013 Test Year is primarily attributable to the operation and maintenance of the new Smart Meter network. The minimal forecast increases in the 2012 Bridge and 2013 Test Years reflect anticipated stability in Distribution Maintenance costs over the next few years.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

35. E4/T3/S2/p.2 and E4/T3/S1/p.1 – Maintenance

Please provide CNPI's vegetation management schedule including tree trimming cycles. Please provide a detailed overview over all costs in the bridge and test year as well as proposed costs in the 2014 and 2015 rate years.

RESPONSE:

CNPI conducts vegetation management on a three-year cycle in each of its service territories. Vegetation management activities include tree trimming, tree removal, and brush clearing. In Fort Erie and Gananoque, vegetation management activities are administered using the same three geographical zones as the Distribution System Inspection Program. In each territory, vegetation management activities are focused in one zone each year, while encroachment issues in other zones that could potentially impact reliability or safety are also addressed. This approach ensures that each zone is regularly maintained on a three-year cycle. CNPI and its vegetation management contractors trim trees enough to ensure that encroachment should not occur prior to the next tree trimming cycle in that zone. Each zone is inspected in the year before vegetation management is performed in said zone, thereby facilitating the advance development of vegetation management plans for that zone.

CNPI's forecast vegetation management costs (Fort Erie and Gananoque combined) for the period 2012 Bridge Year to 2015 Rate Year are as follows:

Year	2012 Bridge	2013 Test	2014 Forecast	2015 Forecast
Forecast Cost ($)	320,187	339,364	335,000	340,000

(OEB)

Operating Costs

Issue 4.2
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

36. Ref: E 4/T2/S11/p.1

Please provide an update of CNPI – PC's Operating Costs, year-to-date expenses in the same detail as shown in on the table on page 1 (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administrative and General and Total OM&A Expenses). Please also provide the figures for the corresponding period in 2010.

RESPONSE:

Please see response on page 2.

Total Operations, Maintenance, and Administrative Expenses - PC								
Description	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Actual June 30, 2011	Actual June 30, 2012
Operating	410,703	360,324	407,031	508,007	444,089	493,132	259,822	224,664
Maintenance	545,753	442,988	545,428	540,395	646,529	595,838	214,479	248,615
Billing and Collection	612,519	576,667	533,156	632,381	695,617	724,206	323,974	299,724
Community Relations	23,698	14,579	10,034	6,901	5,000	13,000	-	-
Administrative and General	2,086,552	2,046,190	1,996,383	1,992,874	1,325,663	956,170	1,200,915	1,037,519
Taxes Other than Income Taxes	70,000	53,880	52,557	52,024	55,000	54,100	25,391	120,307
	3,749,224	3,494,628	3,544,589	3,732,582	3,171,898	2,836,446	2,024,580	1,930,829

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

37. Ref: E4/T2/S5/p.1, Appendix 2-l – OM&A cost per customer – FE/EOP

Appendix 2-l shows CNPI – PC's OM&A cost per customer to be $303 in the 2013 Test Year, down from the $400 2009 Board Approved level.

a) Board staff notes that the customer numbers on Appendix 2-l does not match the proposed customer numbers in Exhibit 3. Please reconcile the two and update the evidence if necessary.
b) Please elaborate on how CNPI – PC's OM&A per customer compares to its peer group.

RESPONSE:

a) Please refer to Board Staff Interrogatory No. 27.

b) To the best of the Company's knowledge, the only source of summarized statistical data on the OM&A costs per customer of all Ontario LDCs is the LDC statistical data published annually by the Board. The most recent year of data currently available is 2010, and is available from the Board at

http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Reporting+and+Record+Keeping+Requirements/Yearbook+of+Distributors .

Based on this data, Port Colborne's 2010 OM&A cost of $382 per customer was higher than the industry average of $282 per customer.

If it is assumed that all other LDCs in the province increase their OM&A cost per customer test year by at least 2% annually between 2010 and 2013, Port

Colborne's 2013 forecast cost of $303 per customer would be in line with the industry average of $299 per customer.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

38. E4/T2/S11/

a) Please provide a table that shows a comparison between 2011 actual and the 2013 test year forecast.
b) Please provide the increase in OM&A expenses between 2011 and 2013 that are due solely to the transition to MIFRS.

RESPONSE:

a) & b)

OM & A Variance Analysis - PC

OEB Account	Expense Description	2011 Actual	2013 Test	MIFRS 2013 Test	2013 Test Versus 2011		2013 Test Versus MIFRS 2013 Test	
					Variance $	Percentage	Variance $	Percentage
	Distribution Expenses - Operation							
5005	Operation Supervision and Engineering	71,372	50,514	50,514	(20,858)	-29%	-	0%
5010	Load Dispatching	87,701	94,858	94,858	7,157	8%	-	0%
5012	Station Buildings and Fixtures Expense	27,860	27,917	27,917	57	0%	-	0%
5016	Distribution Station Equipment - Operation Labour	40,039	38,033	38,033	(2,006)	-5%	-	0%
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	317	317	317	100%	-	0%
5020	Overhead Distribution Lines and Feeders - Operation Labour	38,586	22,888	22,888	(15,698)	-41%	-	0%
5035	Overhead Distribution Transformers- Operation	130	-	-	(130)	-100%	-	0%
5040	Underground Distribution Lines and Feeders - Operation Labour	65,368	46,858	46,858	(18,510)	-28%	-	0%
5055	Underground Distribution Transformers - Operation	408	6,648	6,648	6,240	1530%	-	0%
5065	Meter Expense	130,482	123,386	123,386	(7,096)	-5%	-	0%
5070	Customer Premises - Operation Labour	-	33,944	33,944	33,944	100%	-	0%
5085	Miscellaneous Distribution Expense	46,062	44,769	36,430	(1,293)	-3%	(8,339)	-19%
5096	Other Rent	-	3,000	3,000	3,000	100%	-	0%
	Distribution Expenses - Operation Total	**508,007**	**493,132**	**484,794**	**(14,875)**	-3%	**(8,339)**	-2%
	Distribution Expenses - Maintenance							
5105	Maintenance Supervision and Engineering	44,489	46,639	46,639	2,151	5%	-	0%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	10,134	14,365	14,365	4,231	42%	-	0%
5114	Maintenance of Distribution Station Equipment	30,909	65,422	65,422	34,513	112%	-	0%
5120	Maintenance of Poles, Towers and Fixtures	11,147	17,503	17,503	6,357	57%	-	0%
5125	Maintenance of Overhead Conductors and Devices	110,772	97,236	97,236	(13,536)	-12%	-	0%
5130	Maintenance of Overhead Services	86,314	79,752	79,752	(6,562)	-8%	-	0%
5135	Overhead Distribution Lines and Feeders - Right of Way	92,267	103,626	103,626	11,359	12%	-	0%
5150	Maintenance of Underground Conductors and Devices	7,520	9,818	9,818	2,298	31%	-	0%
5155	Maintenance of Underground Services	8,536	11,216	11,216	2,681	31%	-	0%
5160	Maintenance of Line Transformers	24,553	21,956	21,956	(2,597)	-11%	-	0%
5175	Maintenance of Meters	113,011	124,704	124,704	11,693	10%	-	0%
5195	Maintenance of Other Installations on Customer Premises	744	3,600	3,600	2,856	384%	-	0%
	Distribution Expenses - Maintenance Total	**540,395**	**595,838**	**595,838**	**55,443**	10%	**-**	0%
	Billing and Collection							
5305	Supervision	32,695	63,002	63,002	30,307	93%	-	0%
5310	Meter Reading Expense	28,960	39,672	39,672	10,712	37%	-	0%
5315	Customer Billing	180,176	189,666	189,666	9,490	5%	-	0%
5320	Collecting	138,446	158,112	158,112	19,666	14%	-	0%
5335	Bad Debt Expense	76,247	92,000	92,000	15,753	21%	-	0%
5340	Miscellaneous Customer Accounts Expenses	175,856	181,754	181,754	5,898	3%	-	0%
	Billing and Collection Total	**632,381**	**724,206**	**724,206**	**91,825**	15%	**-**	0%
	Community Relations							
5420	Community Safety Program	-	5,000	5,000	5,000	100%	-	0%
5425	Miscellaneous Customer Service and Informational Expenses	6,901	8,000	8,000	1,099	16%	-	0%
	Community Relations Total	**6,901**	**13,000**	**13,000**	**6,099**	88%	**-**	0%
	Administrative and General Expenses							
5615	General Administrative Salaries and Expenses	691,629	725,458	725,458	33,829	5%	-	0%
5620	Office Supplies and Expenses	25,536	28,666	28,666	3,130	12%	-	0%
5625	Administrative Expense Transferred/Credit	(327,671)	(352,293)	-	(24,622)	8%	352,293	-100%
5630	Outside Services Employed	80,841	67,932	67,932	(12,909)	-16%	-	0%
5635	Property Insurance	19,308	18,600	18,600	(708)	-4%	-	0%
5655	Regulatory Expenses	133,523	129,067	129,067	(4,456)	-3%	-	0%
5665	Miscellaneous General Expenses	7,035	11,848	11,848	4,814	68%	-	0%
5670	Rent	1,171,108	119,673	119,673	(1,051,434)	-90%	-	0%
5675	Maintenance of General Plant	184,936	200,589	200,589	15,653	8%	-	0%
6205	Donations	6,629	6,629	6,629	(0)	0%	-	0%
	Administrative and General Expenses Total	**1,992,874**	**956,170**	**1,308,463**	**(1,036,703)**	-52%	**352,293**	37%
	Total Operating, Maintenance and Administrative Expenses	**3,680,558**	**2,782,346**	**3,126,300**	**(898,212)**	-24%	**343,954**	12%

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

39. Ref: E4/T2/S11/Appendix 2-F and E10/T1/S1/p.1 - RRWF

On page 1 of E10/T1/S1/p.1 CNPI requests approval to include Smart Meter OM&A costs for 2013 into the 2013 Revenue Requirement Work Form.

a) Please provide the increase in OM&A in 2013 as compared to 2011 due to smart meter OM&A.
b) Please confirm whether or not CNPI – PC included any revenue from the Smart meter funding adder in the Distribution Revenue of $5,011,916 (Distribution Revenue at Current Rates) as shown in the RRWF. If so, what is the amount and please re-run RRWF for 2013 excluding the Smart Meter rate adder from the calculation.

RESPONSE:

a) In 2011, OEB 5065 had $1,377 related to Smart Meter OM&A and for 2013, OEB 5065 has $0 budgeted. Additionally, in 2011, OEB 5175 had $49,864 related to Smart Meter OM&A and for 2013, OEB 5175 has $141,720 budgeted.

b) CNPI confirms that any revenue from the Smart Meter funding adder was not included in the Distribution Revenue of $5,011,916.

(OEB)

Operating Costs

Issue 4.1
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

40. E4/T3/S6/p.2 and E4/T3/S5/p.1 – Maintenance

In the detailed OM&A Cost Table CNPI - PC shows a decrease of 18.82% in total Distribution Maintenance costs from 2009 Board-approved to 2009 actual and a subsequent increase of 34.5% increase in the 2013 test year over 2009 actual.

On page 2 of the first reference CNPI states that the increase of $106,134 from 2011 Actual to the 2012 Bridge year is primarily the result of increased forecast expenditures in Overhead Distribution Lines and Feeders – ROW Maintenance ($33,100 due to increased tree trimming) and Maintenance of Distribution of Distribution Station Equipment ($29,100).

Please provide a detailed overview of PC's Vegetation Management including the cycles used. Explain the decrease in 2009 actual as well as subsequent increases in further detail.

RESPONSE:

CNPI conducts vegetation management on a three-year cycle in Port Colborne. Vegetation management activities include tree trimming, tree removal, and brush clearing, and are administered using the same three geographical zones as the Distribution System Inspection Program. Vegetation management activities are focused in one zone each year, while encroachment issues in other zones that could potentially impact reliability or safety are also addressed. This approach ensures that each zone is regularly maintained on a three-year cycle. CNPI and its vegetation management contractors trim trees enough to ensure that encroachment should not occur prior to the next tree trimming cycle in that zone. Each zone is inspected in the year before vegetation management is performed

in said zone, thereby facilitating the advance development of vegetation management plans for that zone.

The decrease of 18.82% from 2009 Board Approved to 2009 Actual occurred primarily because expenditures in line and service maintenance accounts (OEB Account #s 5120, 5125, 5130, 5150, and 5155) were lower than anticipated. This was because of lower than anticipated reactive maintenance in 2009, in addition to a focus on capital projects. Actual expenditures for Meter Maintenance (OEB Account # 5175) were also lower than anticipated, primarily because of the Meter Supervisor's involvement in the Grimsby Power Inc. SAP CIS Migration Project. While the variance in none of these individual accounts exceeded the materiality threshold, the cumulative impact on Distribution Maintenance costs from 2009 Board Approved to 2009 Actual was a decrease of $102,765.

Total Distribution Maintenance costs increased by $102,440 from 2009 Actual to 2010 Actual, which resulted in the cumulative Distribution Maintenance cost for 2010 Actual being 0.06% lower than 2009 Board Approved. The increase occurred primarily because of increases in substation maintenance (OEB Account # 5114), Maintenance Supervision and Engineering (Account 5105), and Meter Maintenance (Account 5175). Increases in the Distribution System Maintenance account were due to a re-focus on substation maintenance activities after the focus on capital projects in 2009. Increases in Maintenance Supervision and Engineering were due to increased oversight of maintenance programs, while Meter Maintenance expenditures returned to 2009 Board Approved levels after the decrease in 2009 Actual.

Total Distribution Maintenance costs decreased by 0.92% from 2010 Actual to 2011 Actual. Decreases in substation maintenance activity and vegetation management were offset by increases in Meter Maintenance (OEB Account

5175). The increase in Meter Maintenance costs was due primarily to the commencing of vendor costs associated with the operation and maintenance of the new Smart Meter network, as well as increased labour spent on activities such as troubleshooting meter communication issues and performing meter checks in response to "high bill" complaints in the aftermath of Smart Meter deployment.

Total Distribution Maintenance costs are anticipated to increase by $106,134 from 2011 Actual to 2012 Bridge Year. This is primarily due to anticipated increases in station maintenance activity and vegetation management expenditures in 2012 Bridge Year. Increases in vegetation management expenditures are anticipated because of the nature of the zone scheduled for 2012, while increased station maintenance is planned after a decrease in 2011 Actual.

Total Distribution Maintenance costs are anticipated to decrease by $50,691 from 2012 Bridge to 2013 Test Year. This is primarily due to an anticipated reduction in vegetation management expenditures in 2013 Test Year because the zone scheduled for 2013 is expected to incur lower costs than the zone in 2012.

When 2009 Board Approved total Distribution Maintenance costs are compared with those forecasted for the 2013 Test Year, the anticipated 2013 Test Year costs are 9.18% above 2009 Board Approved, representing a modest increase over the five-year period. This is a more pertinent comparison than the comparison with 2009 Actual, because of the decreases in 2009 Actual expenditures that were explained earlier. Specific accounts where costs increased from 2009 Board Approved to the 2013 Test Year forecast are associated with the following: incremental costs associated with the operation and maintenance of a new Smart Meter network; increased station maintenance activity that is anticipated as stations age; and increased costs in Maintenance

Supervision and Engineering, reflecting increased oversight of maintenance programs. However, increases in Station maintenance and Maintenance Supervision are approximately offset by decreases in underground plant and overhead line maintenance. The incremental Smart Meter network costs amount to approximately $48,000, which is comparable to the increase of $50,100 in total Distribution Maintenance costs from 2009 Board Approved to 2013 Test Year.

Costs in individual accounts can fluctuate from year to year, depending on system needs, priorities, or the amount of reactive maintenance required. When Smart Meter network costs are excluded from the analysis, 2013 Test Year forecast costs are only 0.38% above 2009 Board Approved expenditures. This demonstrates that total Distribution Maintenance costs for traditional activities have remained level over the five-year period from 2009 Board Approved to 2013 Test Year. The net cost increase from 2009 Board Approved to 2013 Test Year is primarily attributable to the operation and maintenance of the new Smart Meter network.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

40. Ref: Exhibit 4, Tab 1, Schedule 1

Please provide a table in the same level of detail as that shown on page 1 for the actual year to date costs for the most recent period available for 2012. Please provide the corresponding costs for the same period in 2011.

RESPONSE:

Please see answer to OEB question #26.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

41. Ref: Exhibit 4, Tab 2, Schedule 2

a) Please explain what is driving the significant increase in account 5315 (customer billing) from $318,957 in 2011 to $338,481 in 2012 and to $366,923 in 2013.

b) Please explain what is driving the increase in account 4320 (collecting) from $213,400 in 2011 to $276,243 in 2012. Please also explain what is driving the decrease to $252,724 in 2013.

c) Please explain why the bad debt expense (account 5335) is forecast to decline in 2012 from the 2011 level, and then increase by $20,000 in 2013.

d) For each of the account listed in parts (a), (b) and (c) above, please provide the most recent year to date figures available for 2012, along with the costs for the corresponding period in 2011.

e) Please explain the doubling of the expenditure in 2013 relative to 2012 for account 5425.

f) Please explain the new expenditure shown for account 5420 in 2013. Did CNPI have similar expenditures in previous years but the amounts were included in other accounts?

g) Please explain the need for the continued increase in account 5630 (outside service employed) shown in 2009 through 2013.

h) Please explain the significant increase in account 5620 (office supplies and expenses) forecast for 2012 and 2013.

i) Please provide the most recent year to date expenditures in account 5620 for 2012, along with the expenditures recorded in the corresponding period in 2011.

j) Miscellaneous general expenses (account 5665) are forecast to increase by $100,000 between 2011 and 2013. Please explain what is included in this account and what is driving the increase.

k) Maintenance of general plant (account 5675) is forecast to increase by nearly 20% or $166,000 between 2011 and 2013. Please explain what general plant is being maintained and why the increase is so significant.

RESPONSE:

a) The increase from 2011 Actual to 2012 Bridge Year is primarily driven by a forecasted $15,000 increase in labour costs in 2012 due to the implementation of Time-of-Use billing and associated work load. The remainder is a result of expenses associated with bill print outsourcing and MyHydroEye software which will allow customers to view their Time-of-Use consumption information online (although these costs are prorated in 2012 as the services will not be rendered for the full year).

The increase from 2012 Bridge Year to 2013 Test Year is primarily driven by an increase in postage costs (as per Canada Post's announcement to increase postal rates by 3% in 2013) and in addition bill print outsourcing and MyHydroEye costs are reflected for a full year in 2013.

b) The increase from 2011 Actual to the 2012 Bridge Year is the result of increased projected volumes of final collection notices delivered via Express Post and the increased labour associated with collection activities.

The decrease in the 2013 Test Year represents lower projected volumes of final collection notices and slightly lower labour allocations.

c) The debt expense is forecasted to decline slightly in the 2012 Test Year because the 2011 Actual was higher due to the bankruptcy of two general service customers, and subsequent write off. The forecast for the 2012 Bridge Year does not include these items.

The increase in the 2013 Test Year is based on the increasing bad debt expense in both Fort Erie and Gananoque since 2009. This is further impacted by the collection rules set out in the Distribution System Code which require longer payment terms for low income customers and less stringent security deposit requirements.

d) Below are the actual costs for accounts 5315, 5320 and 5335 for the period ending June 30, 2011 and June 30, 2012.

OEB Account	Expense Description	June 30, 2011	June 30, 2012
	Billing and Collection		
5315	Customer Billing	148,853	144,708
5320	Collecting	96,933	105,456
5335	Bad Debt Expense	87,455	79,091

e) The 2013 Test Year inadvertently had $7,000 allocated to account 5425 rather than account 5420 (Community Safety Program) to fund the School Safety Program in Fort Erie, which is run on a four year cycle.

f) Further to the explanation above, this program is run on a four year cycle. In 2009, it was funded through the OPA community initiative funds.

g) The continued increase in OEB account 5630, Outside Services Employed, from 2009 to 2013 is due to the continued increases in the types of items in

this account. It includes items such as system consultants, legal fees, audit fees, and other consultants. One of the main drivers of the increase is in system consultants due to the complex nature and the number of modifications required as a result of ongoing changes to regulatory and accounting requirements. Examples of such changes include the ongoing maintenance of retail settlement functionality within SAP, OEB reporting requirements for Finance and management of new systems implemented to support Time-of-Use billing capabilities.

h) The increase in OEB account 5620, Office Supplies and Expenses, forecast for 2012 and 2013 is explained in Exhibit 4, Tab 3, Schedule 4, pages 2 and 3.

i)

The most recent year-to-date expenditures for OEB account 5620 are in the table below.

OEB Account	Expense Description	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	June 30, 2011	June 30, 2012
5620	Office Supplies and Expenses	272,768	394,158	372,791	494,401	521,137	174,801	217,781

j) The increase in OEB account 5665, Miscellaneous General Expenses, forecast for 2012 and 2013 is primarily due to the inclusion of Algoma Power expenses in the corporate administration departments which have staff residing in Algoma. Example of items included in this account are registration fees, conferences and seminars, letter of credit charges, software maintenance, scrap/inventory adjustments, and miscellaneous expenses. The expenses relating to corporate administration departments will be allocated out to the other business units as described in the BDR report. These allocations go through OEB account 5625, see Exhibit 4, Tab 3, Schedule 4, pages 1 and 4.

k) The significant increase in OEB account 5675, Maintenance of General Plant, forecast for 2012 and 2013 is explained in Exhibit 4, Tab 3, Schedule 4, pages 5 and 6.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

42. Ref: Exhibit 4, Tab 2, Schedule 7

Please show the total costs, by component, associated with the current rates proceeding.

RESPONSE:

Please refer to Appendix 2-H that was provided in response to Board Staff Interrogatory #5.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

43. Ref: Exhibit 4, Tab 4, Schedule 1

a) Please provide an update to the negotiations with the union related to the renewal of the collective agreements as noted on page 7. Please include any percentage increases that have been agreed to.

b) What percentage increases have been included for 2012 and 2013 and included in the revenue requirement in this proceeding?

RESPONSE:

a) Negotiations are currently underway with the two unions referred to in Exhibit 4, Tab 4, Schedule 1. No percentage increases have been agreed to at this point with respect to IBEW (Gananoque). With respect to IBEW (Niagara), the following increases have been agreed to: 2.8% (2012), 2.9% (2013), 3.0% (2014), 3.1% (2015).

b) CNPI has included 3% annual percentage increases for 2012 and 2013 for salary and wages in this Application (Exhibit 4, Tab 4, Schedule 1, Appendix B). The Total Salary and Wages Variance is set out on page 3 of 10. These increases have been included in the revenue requirement. The recently ratified collective agreement with IBEW (Niagara) is slightly less than 3% for 2012 (2.8%) and 2013 (2.9%), but this does not have a material impact on operating costs.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

44. Ref: Exhibit 4, Tab 4, Schedule 1, Appendix B

What is the impact on the revenue requirement for the 2013 test year if the average yearly base wages for the management (including executive) and non-union were reduced to 2% for 2013, the same as the union category?

RESPONSE:

CNPI has forecasted an across the board 3% Average Yearly Base Wage increase for union in the 2013 Test Year. The question in EP 4.0 Operating Costs, IR #5, page 17 refers to a "2%" union average yearly base wage increase in 2013 Test Year, which comes from the Variance Analysis and the filed Appendix 2K. The calculation is based on total CNPI headcount wages divided by total FTEs. What has reduced the average in 2013 from 3% to 2% in the union category is the forecast hiring of the Operations Technician who will be starting at a wage less than the union average, which has the overall impact of reducing average salary increases in that year from 3% to 2%. The wage increases for union are tied into the collective agreement increases which forecast to be approximately 3% in 2012 and 2013.

CNPI has also forecasted an across the board Management Average Yearly Base Wage increase of 3%, which is the same as the union figure. The Management forecast is based upon the Hay forecast of 3%.

The impact on the revenue requirement for using a percentage less than the forecast cannot be readily determined. If CNPI failed to offer competitive wages

that were not consistent with Hay forecasts and/or collective agreements, then it may not be able to recruit, hire and retain the necessary personnel required to maintain a safe and reliable distribution system. CNPI has not analysed the impact that such personnel impairments would have on the system and its revenue requirement. Notwithstanding the above, a 1% change in total salary and wages (Management & Non-Union) in 2013 Test Year (over the 2012 Bridge Year) for CNPI FE/EOP and PC (allocated) is approximately $19,800. See CNPI response to OEB IR 45.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

45. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Page 17 describes the Killaly station and notes that "fans are present, but not wired to any automatic system" on either of the transformers.

a) How are the fans operated if not by automatic systems?

b) Why does CNPI not install the necessary automatic controls?

c) What are the risks of not having fan cooling available automatically?

RESPONSE:

a) Fans on the Killaly DS power transformers are turned on and off manually. Loading is monitored by the SCADA system and fans are turned on if transformer loads approach levels that would require fan cooling. Fans are also turned on during periods of prolonged hot weather.

b) Transformer loading at Killaly DS does not often necessitate fan cooling, so to date the installation of automatic fan control has not been considered a prudent expenditure. It is also a simple matter to turn on the fans during hot weather, which typically occurs only during summer months. CNPI will install automatic fan controls in the future when transformers are more consistently loaded to levels that would require fan cooling.

c) Because of its geographic location, Killaly DS is for the most part an electrically isolated substation with only a single feeder intertie to Catherine DS. This intertie has very limited load transfer capability. The two power

transformers at Killaly DS, therefore, provide backup capacity for each other but are unlikely to carry significant loads from Catherine DS. Predicting loads on the Killaly transformers is, therefore, straightforward. Allied to the fact that loads are continuously monitored via SCADA, the risk of not having automatic fan control (leading, for example, to overloaded transformers without the benefit of cooling fans) is low.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

46. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Page 37 of the DAMP describes the Vegetation Management plan and notes that trimming is typically done on a three year cycle. Page 59 of the DAMP states that "in its service territories CNPI maintains industry-standard systematic vegetation management programmes…". Please provide any studies or reports describing these industry-standard programs.

RESPONSE:

CNPI's vegetation management programs are intended to meet the requirements of Ontario Regulation 22/04*, Electrical Distribution Safety*. CNPI's tree trimming practices are based on the American National Standards Institute (ANSI) Standard A300.

The attached documents describe CNPI's vegetation management programs:

- CNP-VM-001, *Vegetation Management Plan*;
- CNP-VM-002, *Tree Trimming Practices*; and
- CNP-TD-001, *CNPI Tree and Brush Clearing Specification*.

Tree Trimming Practices

Canadian Niagara Power Inc. is dedicated to bringing its customers the most reliable and efficient electrical service available. One of the ways we accomplish this is by integrating a professional tree trimming program into our daily operations.

CNPI implements accepted professional standards for the pruning of trees near power lines. This program provides safe, reliable, and inexpensive electricity. We must keep trees that are located near power lines pruned on a regular cycle. We trim the trees a certain distance away from the power lines to allow for growth until the trees are trimmed during the next cycle.

CNPI trims tree limbs away from overhead power lines in order to achieve two critical objectives:

1. **Public Safety**
2. **Reliability of Electric Service**

Many service outages and interruptions are caused by tree limbs which fall into power lines causing damage to wires, short circuits and other problems. That creates potential danger for you and your property, danger that can be avoided by not planting tall-growing trees under or near electric wires, and by routine tree-trimming.

Trimming Methods

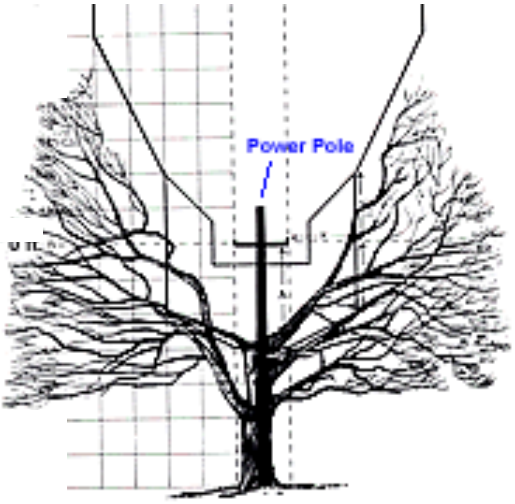
CNPI adheres to the American National Standards Institute (ANSI) A300, Standard Practices for Trees, Shrubs and Other Woody Plant Maintenance. This standard, endorsed by the International Society of Arboriculture, the National Arbor Day Foundation and the Utility Arborist Association, requires tree-trimmers to cut branches back to the "parent limb." This practice allows the pruning cuts to "heal" more rapidly, reducing the chances of insect and disease damage, and promotes a healthier regrowth of branches that are directed away from the power lines.

Pruning considerations include: species of tree, growth and regrowth rates, location of trees in proximity to power lines, voltage of power lines, type of power-line construction, length of pruning cycle, natural tree shape and branching pattern, general tree condition, appearance after pruning and tree-owner input.

Below are illustrations of the types of trimming that CNPI performs. The style used depends on how the tree is placed in relation to the power line and the type of tree that is being trimmed.

V-out (also crown reduction)

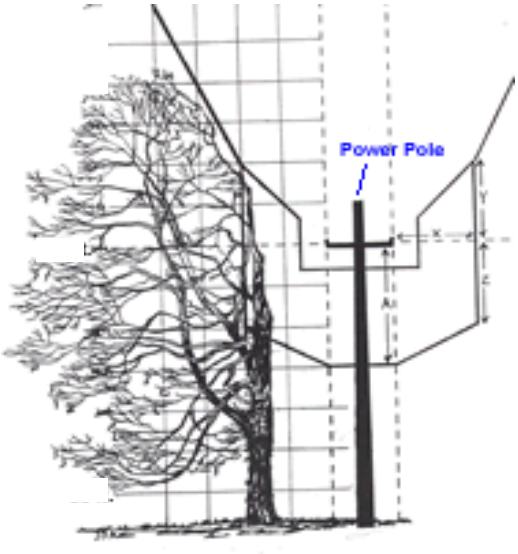




In V-cutting, branches are pruned back toward the center of tree crown.

Side

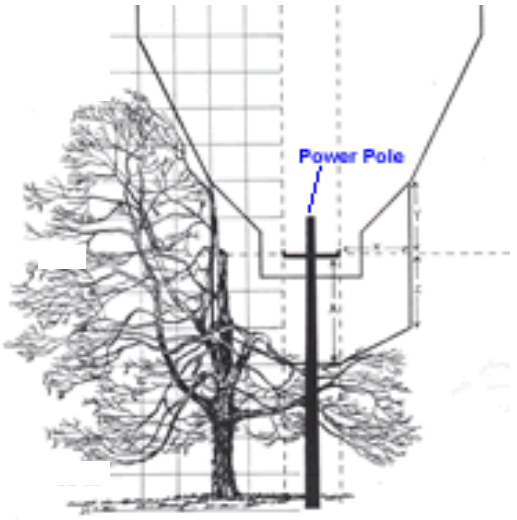




Side-trimming prunes back branches on the side of the tree.

Notch

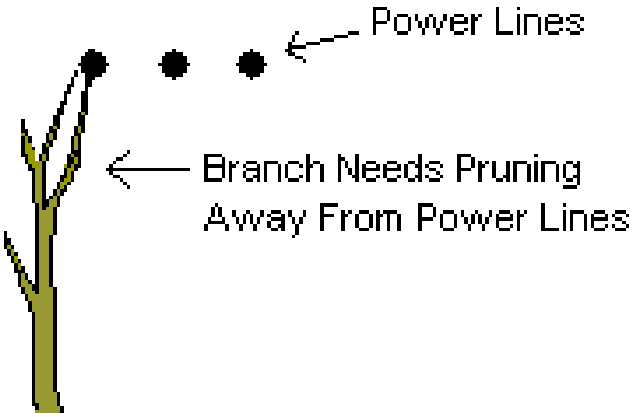




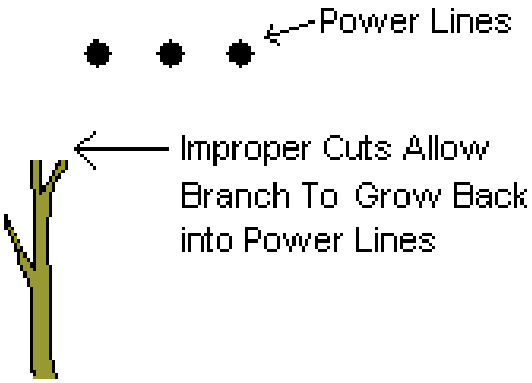
Notch-trimming prunes branches to create a "notch" in the upper tree crown so power lines can pass to the side and above the tree.

CNPI uses the "natural trimming" method (endorsed by the Tree Care Industry Association). It is called natural trimming because branches are pruned back to a natural point of growth in the crown of the tree. Natural trimming is healthier than tree "topping," which is the indiscriminate cutting back of tree branches to reduce the size of the tree crown. Although topping generally leaves the tree with a more uniform or balanced appearance, the International Society of Arboriculture calls topping "perhaps the most harmful pruning practice known." According to the Society, topping stresses trees, makes them more vulnerable to insect and disease infections and causes decay. Canopy may be acceptable only with hardwood trees and trees that are waivered not to be cut as per a CNPI representative and if there has been a canopy already established or in a sensitive area.

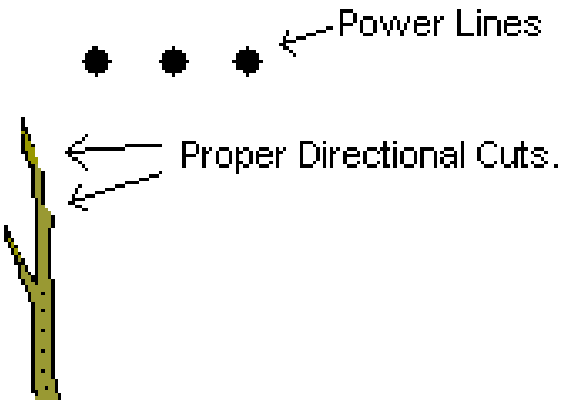
If the branches of a tree are too close to CNPI power lines, the tree must be pruned.



There are, however, different pruning techniques that can benefit the tree while satisfying the needs of CNPI and the property owner or municipality



Directional pruning techniques, which allow the tree to be pruned according to accepted standards while helping to prevent the branch from growing back into the power lines, is often used when pruning trees.



Points to remember:

- Never attempt to trim or remove any tree next to a power line
- Never build tree houses in trees near power lines
- Never climb trees near power lines
- Provincial laws prohibit any person from working within 10 feet of any electric power facility without proper training and certification

Following are answers to the most commonly asked questions about CNPI's tree-trimming practices:

Q: Why Does CNPI Trim Trees?

A: CNPI's Tree Trimming Program is intended to help protect the public, protect property and maintain electric reliability. Short circuits from branches rubbing against power lines, branch breakage and trees being blown over during storms are just a few of the hazardous situations that can occur. Tree trimming is an essential part of maintaining a safe and reliable supply of electricity. Attempting to prune or climb a tree near power lines yourself also can be dangerous. Each year, hundreds of people throughout Canada are injured or killed when they climb or prune trees. Concealed power lines can seriously harm children climbing in the branches.

Power lines broken by falling branches are extremely dangerous and may cause fire, shock or electrocution. By trimming trees and brush we can eliminate safety hazards and reduce tree-related outages. Please remember that any trees interfering with utility power lines can lead to a dangerous situation. Because tree-trimming is so important, legislation exists which requires CNPI to ensure that a minimum clearance space between trees and power lines is maintained.

Q: How does CNPI trim trees?

A: At CNPI we follow the trimming practices recommended by The International Society of Arboriculture. These practices are followed at CNPI :

- Techniques consistent with the practices of natural, lateral and drop crotch trimming shall be utilized.
- Cuts are made back to a main stem or branch of sufficient size. In no case shall deciduous tree limbs be stubbed off at the edge of the clearing limits.
- Wherever possible, all trimming cuts shall be made to direct future growth and sprouting away from the conductors.
- Conifers should be trimmed in a manner that allows them to retain as much of their natural shape as possible.

- All dead branches overhanging primary conductors at any height shall be removed.
- A minimum of cuts should be utilized to achieve required clearances.
- Where practical, cuts should be primarily restricted to large-diameter branches made well within the crown. Shaping through the use of many small diameter branches in the outer crown should be avoided.
- Remove living branches by making cuts as close as possible to the branch collar. Remove dead branches by making cuts as close as possible to the living tissues that surround the dead branch at the base.
- Precautions shall be taken to avoid stripping or tearing of bark when cutting

Q: Why not just shape trees?

A: Shaping was once a popular practice for tree trimming, but it has now been learned that this is not horticultural sound, as it can create a safety hazard to people, property and overhead lines. Shaped trees re-grow quickly with vertical suckers that sprout up from cut branch ends. The suckers are only weakly attached to the branches and are more likely to break off, even in only moderate winds, creating a greater problem of wind borne debris. Tree health may also be affected. This can lead to power blackouts and the need for far more frequent tree trimming. Proper trimming may look severe at first but trees will re-grow at a normal rate and are trained away from power lines. Tree health is maintained and even enhanced by correct cutting at the branch collar.

Q: When will CNPI trim or remove trees?

A: CNPI will trim or remove trees that interfere with or have a potential for interfering with existing CNPI lines, or that obstruct the route of new lines as well as all service wires (wires that run from CNPI poles to the customer's house or building),yard light wires will be trimmed. CNPI will trim trees near streetlights or yard lights to improve illumination. This tree trimming will be in accordance with CNPI Specifications and Guidelines.

If CNPI requires that a tree be trimmed or removed, all branches and wood cut from the tree will be removed by CNPI. The property owner may keep any portion of the wood desired, but CNPI will not cut wood to uniform length or stack the wood. Trees will be cut as close to ground level as possible. CNPI will not remove stumps.

Q: Is permission of the property owner or the municipality necessary before doing tree work?

A: Provision of right-of-way easements or agreements with the municipality grant CNPI the authority to trim trees without property-owner or municipality permission to provide for a safe and reliable electric system. However, CNPI respects the property of its customers or municipality and will notify the property owner or municipality of the need for tree work before trimming is done. In unusual or emergency situations, it may be necessary to trim trees without first notifying the property owner in order to restore service or eliminate safety hazards.

CNPI recommends the removal of trees that will require extensive trimming on a regular basis. However, trees will not be removed without the property owner's or municipality permission.

Q: How does CNPI know when a tree needs to be trimmed or removed?

A: The following priority will be followed in determining when and where tree trimming will be done:

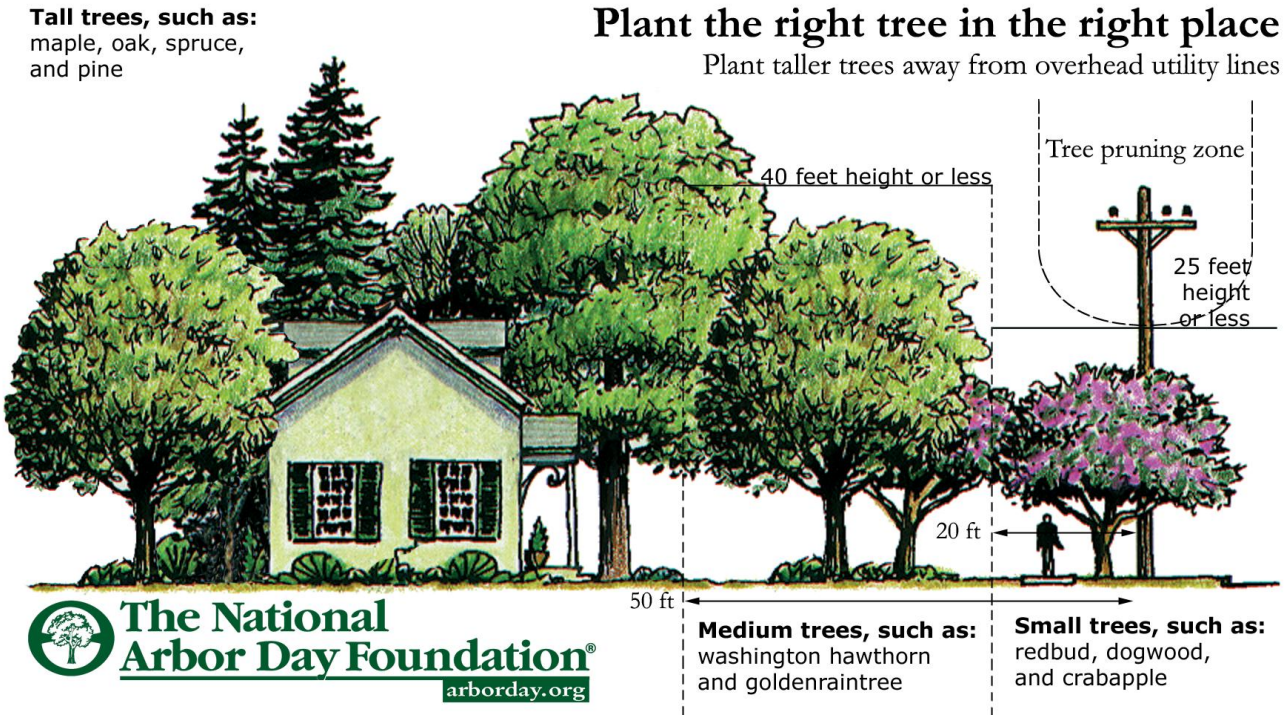
1. Reports of electrical outages caused by trees.
2. Areas where trees have been damaged by storms.
3. During the regular tree-trimming cycle. (every three years)
4. Periodic inspections by CNPI personnel.
5. Reports from customers indicating potential tree/power-line problems.

Q: What qualifications do CNPI contract tree-trimming crews have?

A: It is essential that tree trimming be done properly to ensure safe and dependable electric service, and to provide for the welfare of the trees on your property. To assure that proper tree trimming and removal is performed, CNPI contracts with professional line-clearance tree-trimming firms. These firms are required to be licensed to work in CNPI's service area, and must adhere to all standards, guidelines and laws governing the performance of tree work. Each contractor employee receives ongoing training to achieve and maintain "line-clearance tree-trimmer" certification by the Province.

Q: What can I do to help?

A: Customers can help reduce costs and maintain a pleasant environment by ensuring trees of the right type and size is planted near power lines. Remember "Right Tree, Right Spot." Seek permanent solutions. Do not plant trees near electric lines; or plant only low-growing, compact varieties. The guidelines given here aim to reduce sprouting, reduce the working time in a tree for the tree worker, increase the time between pruning cycles, and help the trees planted near lines to be healthy, safe and as attractive as possible. It is better for the trees, lines and customers to remove fewer but larger branches at nodes. Nodes are where branches shed naturally. It will take time to make all the adjustments given here. But, if we all work together, the adjustments will come. And the public, customers, property, trees, and tree workers will all benefit.



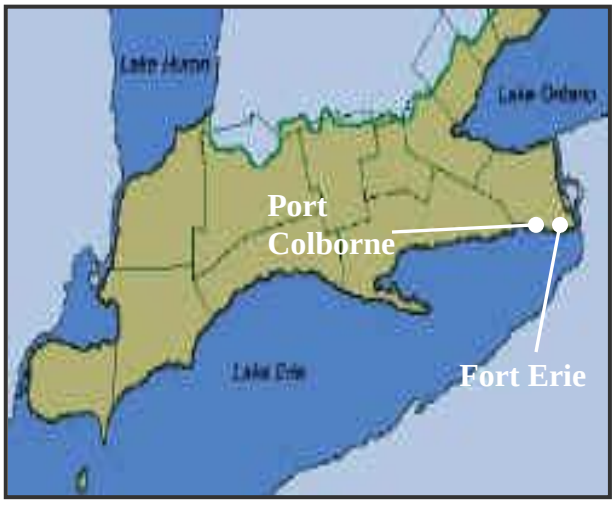
For more information about CNPI's tree-trimming practices, please call 905-871-0330

Vegetation Overview



Ontario's landscape is characterized by its forests. They range in type from the deciduous forest of the Niagara Peninsula area, through the mixed forest of the Great Lakes-St.Lawrence region in central and northwestern Ontario, to the conifer-dominated boreal forest of the north. Sixty-five per cent of Ontario is classified as forested land, totally almost 70 million hectares.

Within this region is the Carolinian Forest. The Carolinian Forest is a life zone in eastern North America characterized primarily by the predominance of deciduous, broad-leaf trees. It extends from the Carolinas in the United States and finds its northern limit in the southwestern section of Ontario.



The region is of particular importance in Canada because it provides the country with the most unique and richest abundance of plant and animal life. Even though the Carolinian Forests of Ontario is quite small compared with other

Canadian vegetation zones, making up only 1% of Canada's total land area, it boasts a greater number of both flora and fauna species than any other ecosystem in Canada. It is estimated that some 2,200 species of herbaceous plants are found here, including 64 species of ferns, at least 110 species of grasses and over 130 different sedge species.

There are 70 species of trees alone. Tree such as various species of ash, birch, chestnut, hickory, oak, maple, basswood and walnut are found here. Tallest of all is the tulip tree.



Canadian Niagara Power Company Incorporated's service territories of Port Colborne and Fort Erie lay entirely within the Carolinian Forest of Ontario. Located along the shores of Lake Erie, this area is also noted for the size and density of its old growth Carolinian Forest. Most notably is Marcy Woods, 280 acres of virgin Carolinian Forest, said by many scientists to be so significant and rich an ecosystem that it rivals only in importance to that of the great cataracts of nearby Niagara.

The sensitivity of its service territories has proven to be an obstacle at times for *Canadian Niagara Power Company Inc*. Excellent relationships with the both municipal governments of Port Colborne and Fort Erie play a vital role in dealing with these sensitive issues and the continuing success of *Canadian Niagara Power Company Inc*. Annual Vegetation Management Plan.

Vegetation Management Plan

Canadian Niagara Power Company Inc. Vegetation Management Plan is broken down into two major and distinct geographical Vegetation Management Areas (VMA). The two Vegetation Management Areas fall within the Municipal Boundaries of Port Colborne and the Municipal
Boundaries of Fort Erie.





Each Municipality is then divided into Vegetation Management Zones (VMZ). Careful consideration is given in the creation of each zone in the Vegetation Management Area. Population density, Presence and density of vegetation and distribution feeder routes play a significant part in the identification and creation in the number of Vegetation Management Zones and their boundaries

Presently, The City of Port Colborne has three (3) Vegetation Management Zones within its municipal boundaries. The Town of Fort Erie has three (3) Vegetation Management Zones.

Within each Vegetation Management Area, each Vegetation Management Zone is trimmed in accordance with the *Company's* Tree and Brush Clearing Specifications CNP-TD-001 and Tree Trimming Practices CNP-VM-002 on a rotating annual cycle. Each year, as the electrical distribution system expands, the Vegetation Management Zones are reviewed and adjusted, if necessary, and accordingly.

Vegetation Management Area

Municipality of Fort Erie

FE Vegetation Management Zone 1

Following Grids: 2727, 2724, 2721, 3024, 3021, 3018, 3324, 3321, 3318, 3315, 3621, 3618, 3615, 3612, 3918, 3915, 3912

FE Vegetation Management Zone 2

Following Grids: 2718, 2715, 2712, 2709, 2706, 3015, 3012, 3009, 3006, 3312, 3309, 3306, 3609, 3606, 3909

FE Vegetation Management Zone 3

Following Grids: 2124, 2121, 2118, 2115, 2112, 2109, 2106, 2103, 2100, 2424, 2421, 2418, 2415, 2412, 2409, 2406, 2403

Vegetation Management Area

Municipality of Port Colborne

PC Vegetation Management Zone 1

Following Grids: 0621, 0618, 0615, 0612, 0921, 0918, 0915, 0912, 1221, 1218, 1215, 1212, 1521, 1518, 1515, 1512, 1824, 1821, 1818, 1815, 1812

PC Vegetation Management Zone 2

Following Grids: 0609, 0606, 0909, 0906, 1209, 1206, 1509, 1506, 1503, 1809, 1806, 1803, 1800

PC Vegetation Management Zone 3

Following Grids: 0012, 0009, 0006, 0321, 0318, 0315, 0312, 0309, 0306

CNPI Vegetation Management Plan Annual Cycle

	Fort Erie VMA	Port Colborne VMA
2010	VMZ 1	VMZ 1
2011	VMZ 2	VMZ 2
2012	VMZ 3	VMZ 3

Tree and Brush Clearance Specification For Electrical Distribution Systems 35kv and Below

Contractor's Responsibilities

1. The Contractor shall do all work, furnish all labor, tools machinery and transportation necessary for the trimming and/or cutting of trees and brush to provide adequate clearance for the representatives to properly maintain and provide to its customers, an uninterruptible supply of electric power. Work at the hourly rate will be designated by a representative of the Company as required. Work at the area rates will be designated on the Company's Property Records primary maps which will be so marked to show any new construction not to be cleared. Work at the area rate is to consist of primary, streetlighting, secondary and service conductor clearance.

2. The Contractor shall trim or cut tree so far as to provide a minimum clearance of:

   - **eighteen (18) inches** or 45.72 cm for the CNP service wires
   - **four (4) feet** or 1.22 meters for CNP primary, secondary and streetlighting wires operating at a voltage up to 5kV.
   - **eight (8) feet** or 2.44 meters for CNP primary wires operating at a voltage from 5kV to 35kV.
   - Additional clearance shall be added to the minimum clearances above to account for vegetation growth between cut cycles.

   Where necessary trimming spoils or mars the shape of the tree, such additional trimming shall be done as to give satisfactory shape and appearance. All dead wood in the tree which, in falling, might interfere with the Company's wires must be removed. All climbing vines growing on poles or guy wires shall be removed, except that it is not required for a man to approach closer than four (4) feet from a conductor when removing said vines.

3. Whenever possible, the Contractor shall contact adjacent property owners to avoid any conflict and to keep the public aware of what is going on near their property. The Contractor, his employees or agents shall present themselves to the property owners in a polite and mannerly fashion. The Contractor shall immediately refer the Customer to the CNP's Representative if conflicts or misunderstandings occur.

4. When brushing, the Contractor shall work in conjunction with CNP's Representative to define boundaries of Road Allowances, Easements, and Right-of-Ways so that that the property rights of others are not infringed upon.

5. All trimming shall be done in accordance with the American National Standards Institute (ANSI) Standard A300 "Standard Practices for Tree, Shrubs and Other Woody Plant Maintenance". The Standard states all cuts shall be made at a parent branch or limb so that no stub shall remain. In cutting back a branch, the cut shall be made at a crotch having a branch at least one-third the diameter of the cut branch.

6. The Contractor shall designate a field supervisor or Foreman to be available to the Company at all reasonable times.

7. The Contractor shall submit a weekly time report, indicating the amount of work accomplished, the location of the work, and a weekly time sheet, showing the classifications of workers and hours worked.

8. The Contractor shall be responsible for ensuring all work is carried out using the standards set forth by the Electrical Utility Safety Rules (Current Edition).

9. The Contractor shall be responsible for ensuring all work is carried out using the standards set forth by the Occupational Health and Safety Act and Regulations for Construction Projects and/or Industrial Establishments.

10. The Contractor shall be responsible for all traffic protection as required to conform to Book 7 Ontario Traffic Manual, Temporary Conditions from the Ministry of Transportation.

11. The Contractor shall be responsible for ensuring all brush is disposed of to the satisfaction of the CNP representative.

12. All work shall be done to the satisfaction of the CNP Representative as to quantity, quality and acceptability. The CNP Representative may reject or condemn any work, which in his opinion, does not satisfy the terms of the contract. Work rejected or condemned shall be, at the Contractor's own expense, replaced by other work acceptable.

13. The contractor shall be responsible for receiving all feeder hold-offs from the control authority as required at the beginning of each day. The contractor shall be responsible for surrendering all feeder hold-offs to the control authority at the end of each day.

Pre-Job Documentation Required:

1 H&S Policy and Program

2 Records of Training (eg. First-Aid/CPR, Electrical Awareness, Utility Work Protection Code, Fall Arrest, Work Area Protection,Traffic Control, Driver's License, TDG, Spills Response, WHMIS
as required)

3 Records of Experience

4 Incident Reporting and Investigation procedures

5 Emergency Response Plan and Contacts (weather, accidents, spills, medical emergencies)

6 Worker Orientation Program

7 Name of Designated First-Aider(s) on site

8 Complete an approved Registration Form (Notice of Project)

9 Certificate of Liability Insurance ($2,000,000)

10 WSIB Clearance Certificate

11 WSIB Experience Rating Statement (NEER, CAD-7, or MAPP)

12 List of WHMIS Controlled Products and Material Safety Data Sheets (MSDS) on site

13 List of Aerial Devices, Radial Boom Derricks and Vehicles used for the work (include description, age, CVOR documentation, yearly structural integrity reports required by Regulation and di-electrical certifications if required.

14 Equipment Certification for Live Line Tools, Fall Arresting Devices, and Rescue Devices.

15 Pre-Job Meeting Minutes

Owner's Responsibilities

1. The owner shall be responsible for providing clear and concise directions to the on-site crew.

2. The owner shall have a CNP representative available via cell phone and telephone during all phases of the work.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

47. Ref: Exhibit 4, Tab 1, Schedule 2

Page 4 of the exhibit discusses the 3 year trimming cycle and states at line 11 that it is "consistent with the practices of other Ontario LDCs".

a) Please provide details of the other Ontario LDCs that follow similar practices.

b) Please estimate the savings in OM&A costs if CNPI followed a 6 year trimming cycle rather than a 3 year cycle.

RESPONSE:

a) While CNPI is not aware of the details of other LDC's practices, to CNPI's knowledge, each LDC develops its vegetation management practices, and cycles, based on the needs and characteristics of its service territory. Some other LDCs neighbouring CNPI that also have 3-year cycles are Welland Hydro, Niagara-on-the-Lake, and St. Catharines (Horizon).

b) CNPI estimates that there would no savings in OM&A costs if a 6-year trimming cycle was adopted instead of the 3-year cycle. The vast majority of CNPI's distribution lines run along road allowances. CNPI's service territories are heavily treed areas, featuring mature trees on municipal or customer-owned property running alongside most roads and adjacent to overhead distribution lines. In hypothetically assessing the viability of a 6-year cycle, CNPI assumes that the question may imply that there is no consequent adverse impact on safety or reliability. At present, with its 3-year cycle CNPI

aims for a minimum 2.44 metre (8 foot) tree trimming cutback from its overhead distribution lines to allow for natural growth prior to the next scheduled trimming cycle. Moving to a 6-year cycle would mean that larger cutbacks would be required, which would result in cutting of thicker limbs and denser foliage. In addition, more trees would have to be removed to provide adequate clearance. Therefore, even though a smaller area would be trimmed each year, the activity in that area would be far more labour-intensive, and no cost savings would result. Moreover, different species of tree grow at different rates. This is far more effectively managed over a shorter cycle, like the 3-year cycle, rather than on a six-year schedule.

Apart from no cost savings being evident from a longer cycle, the large cutbacks that would be required would leave most trees with a severely pruned look, in addition to the removals of many mature trees. From a public relations/customer perspective, this would not be viewed favourably by the municipalities or the general public. Vegetation and trees are part of the natural habitat of CNPI service territories, and CNPI must meet its obligations to operate safely and reliably while being sensitive to the desires of municipalities and the public to maintain the natural beauty of the landscape. CNPI, therefore, estimates no cost savings from a 6-year cycle, and, moreover, does not consider such a long cycle to be practical in its service territories.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

48. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Page 37 describes pole testing done by an external contractor.

a) Please describe what the testing consists of.

b) What is the average cost of testing on a per pole basis?

c) It is mentioned that CNPI is investigating extending the testing to all poles older than 10 years. How did CNPI decide that 10 years is the appropriate age at which to start testing?

RESPONSE:

a) The testing performed by Samtech Inc., under general technical oversight by Dr. Samy Krishnasamy, P.Eng., Ph.D., M. Sc., included:

i. Confirmation of pole ownership (CNPI vs. third party (Bell Canada));
ii. Detailed visual inspection;
iii. Logging of inspection results on paper forms;
iv. Direct measurement of remaining pole strength using specialized equipment;
v. Preparation of electronic database from field observations and measurements; and
vi. Estimation by Dr. Krishnasamy of remaining pole life based on an industry-accepted weighting of multiple factors including extent of wood fiber loss and condition of remaining fiber.

b) The average cost per pole (before taxes) was $24.75.

c) CNPI has not yet decided that 10 years is the appropriate age to start testing. As indicated in the DAMP, CNPI is still in the process of considering this action, based on a recommendation by Dr. Samy Krishnasamy of Samtech Inc.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

49. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program Appendix B

This exhibit shows pole testing results and includes a "pole strength" column.

a) Please describe how pole strength is measured.

b) How should the strength number be understood?

c) Is there a standard used to decide when pole strength is inadequate? If yes, please provide details. If no, please explain how the strength number is used.

RESPONSE:

a) Pole strength is calculated by measuring remaining healthy wood fiber circumferential volume and estimated fiber strength as measured by a resistograph.

b) The estimated pole strength is one of several factors used by Samtech Inc. to predict remaining life of a given pole.

c) CSA Standard C22.3 Part 1 for Overhead Systems, as referenced by Ontario Regulation 22/04, outlines the requirements for distribution pole strengths. The strength number is used as one of the factors for evaluating remaining pole life. In aggregate, these results are used to assist in CNPI's capital asset renewal program.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

50. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

On page 60 of the exhibit, mention is made of CNPI's plans to eventually have a single control room to monitor and control all of its own and its affiliate's service territories.

a) Please elaborate on the potential locations under consideration for the control room.

b) Cornwall Electric currently provides system control services to EOP. What financial penalties would CNPI be liable for if it discontinued using this service?

c) Would the control room also provide service to CNPI's affiliated generating stations?

RESPONSE:

a) Potential locations for control under consideration for the Fort Erie Control Room are Fort Erie, Port Colborne, and Gananoque.

b) CNPI would not be liable for financial penalties if it discontinued using the Cornwall Electric system control service to EOP.

c) No.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

51. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Page 70 shows asset condition for poles tested. The chart appears to rely solely on age of poles to determine the "years to replace cohort" variable. Please elaborate on the criteria used to plan for and ultimately replace poles.

RESPONSE:

The referenced charts were not used to determine the 'years to replace' cohort. The charts are organizational presentations of previously calculated pole condition and estimated remaining life results.

Dr. Samy Krishnasamy, from Samtech Inc., performed evaluations on each individual pole to determine its expected remaining life. This evaluation applied many factors, which included age, visual condition, and remaining wood strength. Please refer to Energy Probe interrogatory 4.1, #10, (CNPI reference #49) for further information.

Once results for the sample groups were derived, the results were extrapolated to the entire population of CNPI's poles.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

52. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Page 74 shows "Extrapolated Results for Entire Pole Population" for all of CNPI's poles. Please explain the methodology used to produce the extrapolation.

RESPONSE:

CNPI maintains a record of each of its poles, so the total number of poles in the population is known. The random selection of the sample group areas is described and shown in the Distribution Asset Management Program (DAMP). The number of poles in the sample group areas (maps) were known from corporate records and confirmed during testing. The extrapolation was performed by applying a simple ratio of total poles to tested poles for the results of the pole testing. This extrapolation was performed separately for each region of CNPI.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

53. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

Section 7.3.2 on page 79 discusses Measuring Asset Condition. The second criterium reads "historical trends in actual distribution transformer usage due". The statement appears to be incomplete (i.e. "due" to what?). Please advise how to interpret the statement.

RESPONSE:

Section 7.3.2(2) should read in its entirety "2) historical trends in actual distribution transformer usage." The inclusion of the final word "due" is a typographical error.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

54. Ref: Exhibit 2, Tab 3, Schedule 1 Distribution Asset Management Program

On page 81 reference is made to "probabilistic techniques" to predict when distribution assets are nearing end of life. Please describe the "probabilistic techniques" used.

RESPONSE:

CNPI has determined that the long-term costs of detailed and ongoing individual asset tracking programs for many of its asset types would greatly exceed the costs of the assets themselves.

Instead, CNPI applies probabilistic techniques, based on the following:

- industry-standard values for estimated asset life and rate of failure; and
- extrapolations from field observations, inspections, and testing to determine where and when optimal asset replacement should be performed on CNPI's distribution system.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

55. Ref: Exhibit 2, Tab 6, Schedule 1 pages 6-7

These pages of the exhibit discuss reliability for the EOP system and show outage statistics in two tables. Table III on page 5 shows statistics including outages due to loss of supply. Table IV on page 6 shows statistics excluding loss of supply. The numbers for SAIFI, SAIDI and CAIDI in 2011 are identical in both tables. Please confirm that this would mean that there were no loss of supply outages in 2011 in EOP.

RESPONSE:

There were no Loss of Supply outages in 2011 in EOP.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

56. Ref: Exhibit 2, Tab 6, Schedule 2 pages 3-4

This exhibit discusses reliability for the Port Colborne system and shows outage statistics in two tables. Table I on page 3 shows statistics including loss of supply and Table II on page 4 shows statistics excluding loss of supply. The numbers for 2009, 2010 and 2011 are the same. Please confirm that this means there were no loss of supply outages in these three years and comment on whether this is usual for the PC system.

RESPONSE:

There were no Loss of Supply outages in Port Colborne in 2009, 2010, and 2011. However, there were Loss of Supply outages in Port Colborne in 2007, 2008, and 2012 year-to-date. Data over the six-year period from 2007-2012 indicates that in any given year there is a 50% chance of a Loss of Supply outage occurring. Therefore, the absence of Loss of Supply outages in the three years mentioned in the Interrogatory is not considered to be usual for the Port Colborne system.

(EP)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

57. Ref: Exhibit 4, Tab 1, Schedule 1 page 1

The chart on this page shows that actual FE/EOP OM&A expenses for 2009 – 2011 were significantly lower than 2009 Board approved.

a) Please confirm that the 2009 Board approved figures were used to set rates for the 2009 – 2011 period.

b) Please comment on the apparent over collection of about $1.4 M in rates during the three years for OM&A costs and whether the Board should consider requiring CNPI to compensate customers for this over collection.

RESPONSE:

a) Confirmed.

b) CNPI would not describe its actual OM&A expenses relative to its Board approved budget as an "over collection", and in fact CNPI's actual revenue was less than Board approval levels. CNPI does not believe that the Board should consider requiring CNPI to compensate customers for what Energy Probe has described as an "apparent over collection".

(SEC)

4. Operating Costs

4.1 Is the proposed CNPI – Fort Erie/Gananoque forecast for total OM&A for the test year appropriate?

10. [Ex.4/3/1/p.1-2]
Please update the table to include a column for 2012 year-to-date.

RESPONSE :

OM & A Detailed Costs Table
FE and EOP

OEB Account	Expense Description	2009 Board Approved	2009 Actual	Variance from 2009 EDR	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge	Variance from 2011 Actual	2013 Test	Variance from 2012 Bridge	Actual June 30, 2012	Variance from 2012 Bridge divided by 2
	Distribution Expenses - Operation													
5005	Operation Supervision and Engineering	82,483	69,245	(13,239)	68,088	(1,157)	101,285	33,197	77,853	(23,432)	100,859	23,007	43,872	4,946
5010	Load Dispatching	196,095	162,983	(33,111)	174,280	11,297	155,499	(18,782)	188,972	33,473	164,182	(24,790)	90,294	(4,192)
5012	Station Buildings and Fixtures Expense	92,992	97,124	4,132	103,678	6,554	130,309	26,631	125,256	(5,053)	118,200	(7,056)	50,957	(11,671)
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-	-	-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	193,407	55,353	(138,055)	102,711	47,359	74,945	(27,766)	53,318	(21,627)	50,764	(2,554)	46,019	19,360
5017	Distribution Station Equipment - Operation Supplies and Expenses	3,600	13,830	10,230	12,086	(1,744)	10,719	(1,367)	13,796	3,078	13,920	124	13,288	6,390
5020	Overhead Distribution Lines and Feeders - Operation Labour	35,594	64,648	29,055	55,320	(9,329)	53,193	(2,127)	65,171	11,978	50,180	(14,991)	37,020	4,434
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	26,400	17,810	(8,590)	18,624	814	15,027	(3,597)	19,620	4,593	15,720	(3,900)	21,204	11,394
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5035	Overhead Distribution Transformers- Operation	11,587	7,950	(3,637)	13,894	5,944	1,163	(12,731)	8,227	7,064	1,580	(6,647)	-	(4,114)
5040	Underground Distribution Lines and Feeders - Operation Labour	95,009	81,575	(13,434)	88,292	6,717	99,047	10,755	91,709	(7,337)	116,706	24,997	42,651	(3,204)
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	1,200	778	(422)	(158)	(936)	1,012	1,170	1,000	(12)	1,600	600	1,135	635
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	4,165	-	(4,165)	1,161	1,161	-	(1,161)	1,870	1,870	1,519	(351)	65	(870)
5065	Meter Expense	168,067	137,333	(30,734)	204,275	66,943	223,222	18,947	197,479	(25,743)	201,118	3,640	129,762	31,023
5070	Customer Premises - Operation Labour	592	164	(428)	-	(164)	238	238	44,213	43,975	13,722	(30,491)	-	(22,107)
5075	Customer Premises - Materials and Expenses	8,400	717	(7,683)	-	(717)	-	-	4,800	4,800	6,000	1,200	-	(2,400)
5085	Miscellaneous Distribution Expense	172,576	70,746	(101,830)	87,962	17,216	108,171	20,209	79,065	(29,106)	86,756	7,691	52,825	13,293
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	451	451	315	(136)	-	(315)	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
5096	Other Rent	-	-	-	-	-	-	-	-	-	-	-	488	488
	Distribution Expenses - Operation Total	**1,092,166**	**780,256**	**(311,909)**	**930,665**	**150,409**	**974,144**	**43,479**	**972,350**	**(1,794)**	**942,827**	**(29,522)**	**529,579**	**43,404**
	Distribution Expenses - Maintenance													
5105	Maintenance Supervision and Engineering	24,455	15,840	(8,615)	45,927	30,087	69,536	23,609	54,831	(14,705)	51,543	(3,288)	38,218	10,802
5110	Maintenance of Buildings and Fixtures - Distribution Stations	11,502	9,005	(2,497)	12,764	3,759	26,554	13,790	7,122	(19,431)	22,841	15,719	5,342	1,781
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
5114	Maintenance of Distribution Station Equipment	39,492	44,643	5,151	63,941	19,298	72,501	8,559	89,748	17,247	86,811	(2,937)	84,360	39,486
5120	Maintenance of Poles, Towers and Fixtures	44,250	32,662	(11,588)	50,171	17,510	45,547	(4,624)	43,359	(2,188)	44,170	810	19,567	(2,112)
5125	Maintenance of Overhead Conductors and Devices	207,149	162,041	(45,108)	163,130	1,089	173,016	9,886	165,178	(7,838)	186,962	21,784	93,839	11,250
5130	Maintenance of Overhead Services	228,364	206,534	(21,830)	200,996	(5,539)	215,665	14,670	206,404	(9,262)	192,082	(14,321)	96,721	(6,481)
5135	Overhead Distribution Lines and Feeders - Right of Way	284,660	321,931	37,271	310,941	(10,990)	314,480	3,538	320,187	5,708	339,364	19,177	159,210	(884)
5145	Maintenance of Underground Conduit	692	-	(692)	450	450	606	156	-	(606)	-	-	-	-
5150	Maintenance of Underground Conductors and Devices	70,644	16,222	(54,422)	28,863	12,641	27,101	(1,762)	30,484	3,383	30,022	(463)	32,032	16,790
5155	Maintenance of Underground Services	83,556	22,698	(60,858)	21,646	(1,052)	44,016	22,370	25,011	(19,005)	33,877	8,865	17,804	5,299
5160	Maintenance of Line Transformers	69,510	104,009	34,499	115,971	11,962	94,589	(21,382)	116,265	21,675	73,185	(43,080)	42,631	(15,502)
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-	-
5170	Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-	-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5175	Maintenance of Meters	108,973	81,946	(27,027)	104,794	22,848	203,490	98,696	228,910	25,420	255,783	26,873	104,904	(9,551)
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-	-	-	-	-
5195	Maintenance of Other Installations on Customer Premises	3,600	216	(3,384)	226	10	-	(226)	300	300	-	(300)	-	(150)
	Distribution Expenses - Maintenance Total	**1,176,848**	**1,017,747**	**(159,101)**	**1,119,821**	**102,074**	**1,287,101**	**167,280**	**1,287,800**	**699**	**1,316,640**	**28,840**	**694,628**	**50,728**

	Billing and Collection													
5305	Supervision	93,534	56,233	(37,301)	75,473	19,241	78,088	2,615	126,655	48,567	104,555	(22,101)	33,216	(30,112)
5310	Meter Reading Expense	228,303	253,771	25,468	178,238	(75,533)	40,740	(137,498)	41,521	781	53,354	11,833	17,298	(3,463)
5315	Customer Billing	324,709	254,390	(70,319)	296,090	41,700	318,957	22,866	338,481	19,524	366,923	28,442	144,708	(24,532)
5320	Collecting	161,693	171,179	9,485	215,377	44,199	213,400	(1,977)	276,243	62,843	252,724	(23,518)	105,456	(32,666)
5325	Collecting- Cash Over and Short	-	-	-	-	-	-	-	-	-	-	-	-	-
5330	Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-	-
5335	Bad Debt Expense	64,400	87,254	22,854	129,715	42,461	145,410	15,695	140,000	(5,410)	160,000	20,000	79,091	9,091
5340	Miscellaneous Customer Accounts Expenses	342,601	330,840	(11,761)	371,660	40,820	458,413	86,753	355,798	(102,615)	399,291	43,494	209,807	31,909
	Billing and Collection Total	**1,215,240**	**1,153,666**	**(61,574)**	**1,266,553**	**112,887**	**1,255,007**	**(11,546)**	**1,278,697**	**23,689**	**1,336,847**	**58,150**	**589,576**	**(49,773)**
	Community Relations													
5405	Supervision	-	-	-	-	-	-	-	-	-	-	-	-	-
5410	Community Relations - Sundry	21,064	13,475	(7,589)	6,076	(7,399)	750	(5,326)	-	(750)	-	-	834	834
5415	Energy Conservation	1,000	-	(1,000)	-	-	-	-	-	-	-	-	-	-
5420	Community Safety Program	6,400	-	(6,400)	-	-	-	-	-	-	4,200	4,200	-	-
5425	Miscellaneous Customer Service and Informational Expenses	16,366	8,945	(7,421)	7,621	(1,324)	10,168	2,547	9,400	(768)	18,500	9,100	-	(4,700)
5505	Supervision	-	-	-	-	-	-	-	-	-	-	-	-	-
5510	Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5515	Advertising Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5660	General Advertising Expenses	3,000	3,881	881	13,869	9,988	2,220	(11,649)	4,650	2,430	5,000	350	3,311	986
	Community Relations Total	**47,830**	**26,301**	**(21,529)**	**27,566**	**1,264**	**13,138**	**(14,427)**	**14,050**	**912**	**27,700**	**13,650**	**4,145**	**(2,880)**
	Administrative and General Expenses													
5605	Executive Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5610	Management Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5615	General Administrative Salaries and Expenses	2,601,540	2,600,592	(948)	2,983,349	382,758	3,177,159	193,809	3,858,761	681,603	3,947,271	88,510	1,998,869	69,488
5620	Office Supplies and Expenses	366,675	272,768	(93,907)	394,158	121,390	372,791	(21,367)	494,401	121,610	521,137	26,736	217,781	(29,420)
5625	Administrative Expense Transferred/Credit	(3,349,803)	(3,393,538)	(43,735)	(3,570,565)	(177,026)	(4,222,883)	(652,318)	(5,394,671)	(1,171,788)	(5,475,410)	(80,740)	(2,903,486)	(206,150)
5630	Outside Services Employed	270,096	217,590	(52,505)	252,427	34,837	304,875	52,448	354,796	49,922	392,764	37,968	154,047	(23,352)
5635	Property Insurance	116,200	53,169	(63,031)	42,219	(10,950)	39,824	(2,396)	42,700	2,876	39,400	(3,300)	19,811	(1,539)
5640	Injuries and Damages	-	525	525	-	(525)	-	-	-	-	-	-	-	-
5645	Employee Pensions and Benefits	671,614	598,461	(73,153)	697,565	99,104	866,151	168,586	1,160,051	293,900	1,189,718	29,667	624,225	44,199
5650	Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-	-	-
5655	Regulatory Expenses	196,991	197,252	261	156,685	(40,568)	163,234	6,550	193,955	30,721	191,623	(2,332)	66,825	(30,152)
5665	Miscellaneous General Expenses	73,840	83,315	9,475	100,069	16,754	65,527	(34,541)	123,320	57,793	165,397	42,077	46,414	(15,246)
5670	Rent	247,166	247,166	-	252,110	4,943	254,049	1,939	218,664	(35,385)	223,037	4,373	295,262	185,930
5675	Maintenance of General Plant	932,724	854,318	(78,406)	800,543	(53,775)	846,033	45,490	992,847	146,814	1,012,179	19,332	390,561	(105,862)
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-	-
5695	OM&A Contra Account	-	(3,589)	(3,589)	(5,987)	(2,398)	-	5,987	-	-	-	-	-	-
6205	Donations	-	-	-	-	-	14,469	14,469	14,450	(19)	14,470	20	14,469	7,244
	Administrative and General Expenses Total	**2,127,042**	**1,728,030**	**(399,013)**	**2,102,573**	**374,543**	**1,881,227**	**(221,345)**	**2,059,275**	**178,048**	**2,221,587**	**162,312**	**924,778**	**(104,859)**
	Taxes Other Than Income Taxes													
6105	Taxes Other Than Income Taxes (Note less capital taxes)	59,000	63,737	4,737	35,376	(28,361)	60,149	24,773	55,500	(4,649)	62,600	7,100	30,072	2,322
	Taxes Total	**59,000**	**63,737**	**4,737**	**35,376**	**(28,361)**	**60,149**	**24,773**	**55,500**	**(4,649)**	**62,600**	**7,100**	**30,072**	**2,322**
	Total Operating, Maintenance and Administrative Expenses	**5,718,126**	**4,769,738**	**(948,389)**	**5,482,553**	**712,815**	**5,470,766**	**(11,787)**	**5,667,671**	**196,905**	**5,908,201**	**240,530**	**2,772,778**	**(61,058)**
	Power Supply Expenses													
4705	Power Purchased	21,511,407	20,850,603	(660,804)	23,499,918	2,649,315	24,867,724	1,367,806	26,317,776	1,450,053	26,322,125	4,349	12,433,051	(725,838)
4708	Charges-WMS	2,347,702	2,230,164	(117,538)	2,318,995	88,832	2,286,611	(32,384)	2,242,017	(44,594)	2,192,061	(49,957)	1,070,549	(50,460)
4710	Cost of Power Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
4712	Charges-One-Time	-	-	-	-	-	-	-	-	-	-	-	-	-
4714	Charges-NW	1,724,442	1,572,131	(152,311)	1,844,966	272,835	1,978,534	133,569	2,066,535	88,001	2,280,061	213,527	994,865	(38,403)
4716	Charges-CN	1,661,809	1,540,447	(121,362)	1,668,341	127,893	1,670,100	1,759	1,695,078	24,978	1,787,432	92,354	810,239	(37,300)
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
4750	Charges - LV	95,837	92,971	(2,867)	48,046	(44,924)	91,709	43,663	91,464	(245)	91,709	245	46,683	951
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-	-
	Power Supply Expenses Total	**27,341,197**	**26,286,316**	**(1,054,882)**	**29,380,266**	**3,093,950**	**30,894,679**	**1,514,413**	**32,412,870**	**1,518,192**	**32,673,389**	**260,518**	**15,355,386**	**(851,049)**
	Total Expenses for Working Capital	**33,059,324**	**31,056,054**	**(2,003,270)**	**34,862,819**	**3,806,766**	**36,365,444**	**1,502,625**	**38,080,541**	**1,715,097**	**38,581,589**	**501,048**	**18,128,164**	**(912,107)**
	Amortization Expenses													
5705	Amortization Expense - Property, Plant, and Equipment	2,459,267	2,948,944	489,677	2,547,873	(401,071)	2,418,556	(129,317)	2,416,711	(1,844)	2,996,035	579,324	1,662,861	454,505
5715	Amortization of Intangibles and Other Electric Plant	-	2,479	2,479	2,479	-	2,479	(0)	-	(2,479)	-	-	-	-
	Amortization Expenses Total	**2,459,267**	**2,951,423**	**492,156**	**2,550,352**	**(401,071)**	**2,421,035**	**(129,317)**	**2,416,711**	**(4,324)**	**2,996,035**	**579,324**	**1,662,861**	**454,505**
	Grand Total	**35,518,590**	**34,007,476**	**(1,511,114)**	**37,413,171**	**3,405,695**	**38,786,479**	**1,373,308**	**40,497,253**	**1,710,773**	**41,577,624**	**1,080,372**	**19,791,025**	**(457,601)**

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

39. Reference: Exhibit 4, Tab 2, Schedule 2, page 1, Schedule 2, page 1 / Schedule 11, page 1

a) In respect to Port Colborne, CNPI states that the Board approved a lease payment of $1,000,000 in 2009. Please confirm that these payments are found under account 5670 Rent.

b) Please explain how the lease payments approved by the Board were calculated.

c) Please provide the lease payment amounts in 2010 and 2011.

RESPONSE:

a) The approved leased payments for Port Colborne are included in OEB account 5670 Rent.

b) The Board in its Decision dated September 30, 2009 (EB-2008-0224) made the following statement regarding the determination of the approved lease payment.

"The technical complexities of determining the appropriate revenue requirement for 2009 based on hypothetical scenarios and assumptions are numerous and cannot be sorted out without substantial effort and costs by all parties, which at the end would burden ratepayers. Even then, the nature and complexity of the issue calls for a considerable degree of judgment. The Board concluded that it is best to deem a revenue requirement reduction in the circumstances. The Board considers a cost of $1.0 million for the annual lease payments as the reasonable amount to be recovered in rates for 2009

rather than the proposed $1.5 million reflected in the proposed revenue requirement, and it so finds. “

c) The lease payments in OEB account 5670 Rent for 2010 and 2011 were $1,000,000 in each year.

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

40. Reference: Exhibit 4, Tab 1, Schedule 1, page 3

a) CNPI implies that operating cost for Port Colborne has declined on an actual and constant dollar basis. Does this analysis include or exclude the lease payment for all years?

b) If it includes the lease payment for part of the period please explain why the 2009 to 2013 costs analysis is an "apples-to-apples" comparison?

c) Please recalculate the analysis removing the lease payment for all years and using Statistic Canada's actual CPI inflator for the years 2009, 2010 and 2011 and the current 2012 annual inflation figure (i.e. June 2011-June 2012).

RESPONSE:

a) On page 2 (E4/T1/S3) states;

"OM&A expenses have increased by 3.2% since the 2009 Board Approved (excludes the $1.0 million base payment in 2009 Board Approved)."

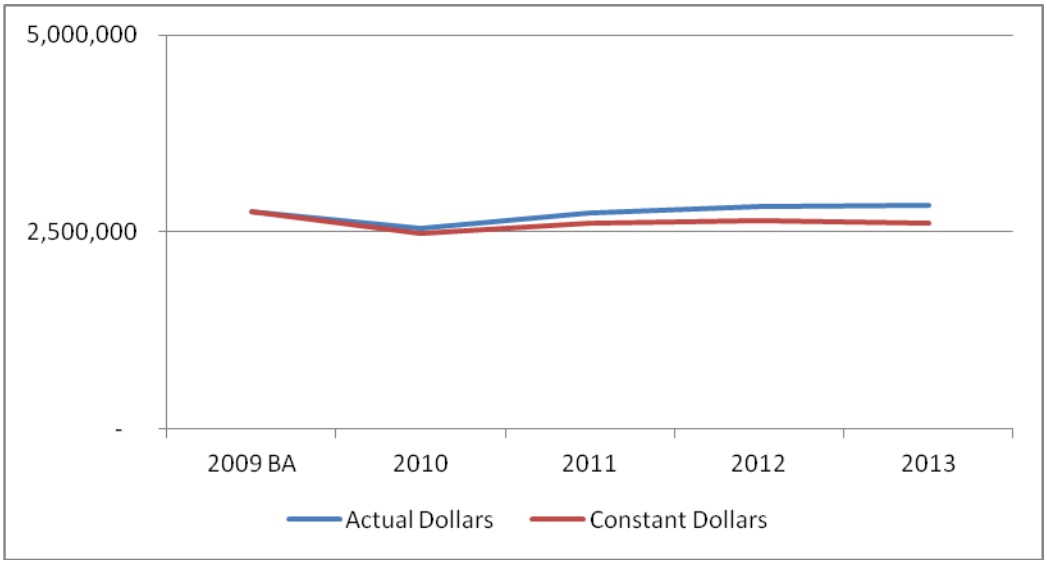
The actual dollar statement above shown on page 2 excludes the lease payment. The graph on page 3 inadvertently includes the lease payment.

b) The graph on page 3 inadvertently includes the lease payment.

c) The graph below excludes the lease payment for each year.

The graph has been updated based on actual inflation rates (i.e. 2010: 2.4%; 2011: 2.3%; 2012: 1.5% (June'11 to June'12); and 2013:– 2% (Bank of Canada target)).

In constant dollars, OM&A expenses have declined by 5% since the 2009 Board Approved.



(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

41. Reference: Exhibit 2, Tab 2, Schedule 10, page 1

a) Please explain how the bad debt expense for 2012 for all service territories is calculated.

RESPONSE:

a) This response is in reference to Exhibit 4, Tab 2, Schedule 2, page 1. Bad debt expense is estimated based on the previous year and adjusted based on historical trending of previous years. Any anomalies such as a large bankruptcy would be taken into consideration when forecasting future years. The same mechanism is utilized in all service territories.

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

42. Reference: Exhibit 4, Tab 2, Schedule 2, page 1/Schedule 11, page 1/ Exhibit 4, Tab 3, Schedule 3, page 2

a) Customer Billing and Collection costs (accounts 5315 and 5320) for Fort Erie-EOP are projected to increase by over 45% from 2009 actuals. The reasons provided for this increase are changes to staffing and postage costs. Please provide the total postage cost in 2009 and the expected postage cost in 2012.

RESPONSE:

a) The total postage cost in 2009 was $158,109 and the expected postage cost in 2012 is $211,648. This includes mail delivery and Express Post costs for delivery of final collection notices.

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

43. Reference: Exhibit 4, Tab 2, Schedule 2, page 1 / Exhibit 4, Tab 3, Schedule 3, page 2

a) Miscellaneous General Expenses (accounts 5665) for Fort Erie-EOP are project to increase by nearly 100% from 2009 actuals. The explanation given suggests that this account has had significant changes in labour allocations. Please explain what activities are recorded in this account.

RESPONSE:

Please see response to Energy Probe #41 (4.1, #2, j).

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

44. Reference: Exhibit 4, Tab 2, Schedule 11, page 1

a) Miscellaneous Customer Account Expenses (accounts 5340) is projected to increase by 30% from 2009 actuals. Please explain the reasons for this increase.

RESPONSE:

a) There are two primary reasons for this increase. The first is a result of costs associated with bank fees, advertising, credit bureau charges and damage claims being charged directly to the cost centre in 2009 which were subsequently were spread amongst all orders. In 2010, the process changed resulting in the charges being allocated directly to account 5340.

In addition, the 2009 Actual had reduced labour allocations due to the reassignment of customer service personnel to IT projects and the 2013 Test Year includes increased labour allocations to account 5340.

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

45. Reference: Exhibit 4, Tab 2, Schedule 9 & 17, page 1

a) Please provide the calculation for the LEAP funding for both service territories.

RESPONSE:

LEAP funding is based on 0.12% of the 2009 EDR Revenue Requirement. The calculations are as follows:

Exhibit 4, Tab 2, Schedule 9 is the sum of the following:

Fort Erie: $9,712,149 *.12% = $11,654.60

Gananoque: $2,345,427 *.12% = $2,814.51

Exhibit 4, Tab 2, Schedule 17

Port Colborne: $5,524,535*.12% = $6,629.08

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

46. Reference: Exhibit 4, Tab 4, Schedule 1, Appendix A/Appendix B page 2

CNPI explains that the variance between 2009 Board Approved and 2009 actual FTEs and total compensation are due to a change in the allocation methodology.

a) What was the total compensation amount used by CNPI for the calculation of the 2008 cost of service rates (i.e. was figure of $5,343,682 reported in the compensation table used in the calculation of rates)?

b) If this was not the amount used for the calculation of rates in 2008 please provide the amount that was used for the purpose of calculating rates.

c) Is the difference between the 2008 Board Approved figure of $5.3 million and the 2009 figure of $6.0 million due solely due to changes in the allocation of costs? If so, please explain where the approximately $700,000 of compensation costs was previously allocated.

RESPONSE:

a) Yes. The amounts referred to in the columns “2009 Board Approved” in the Appendix 2K filed with this Application are the same amounts used by CNPI in the 2008 cost of service application. For example, the figure of $5,343,682 represents the Total Salary and Wages (i.e., in 2008 = Total Compensation – Benefits) used to determine Total Compensation in the 2008 cost of service applications (for the aggregate of Fort Erie, Gananoque and Port Colborne).

b) Not applicable.

c) Yes, the difference in the amount of Total Salary and Wages in 2009 Board Approved and 2009 Actual is primarily due to changes with the allocation methodology of using total headcount compared with costs (and FTEs) allocated only to the business units CNPI FE/EOP and CNPI/PC. The difference would be due primarily to allocations to business units other than CNPI/FE and CNPI/PC (ie, FTO, CE and CNPI Tx). Since total headcount uses a larger number of FTE's, the total headcount cost calculation is greater than the allocated cost amount which uses a lower number of FTEs.

In respect of compensation costs on an allocated basis and in response to OEB IR 45, CNPI has prepared a second version of Appendix 2K (Allocated) on an allocated FTE basis using the BDR Report (as opposed to actual headcount used in the filing of Appendix 2K with the Application). Please refer to response to OEB IR 45.

(VECC)

4. Operating Costs

4.1/4.2 Is the proposed CNPI forecast for OM&A for the test year appropriate?

47. Reference: Exhibit 4, Tab 4, Schedule1, Appendix B, page 2

a) Please provide the BDR Report referred to in the above reference.

RESPONSE:

a) The 2009 BDR Report was filed in evidence in EB-2008-0224/0223/0222 as Exhibit 4, Tab 2, Schedule 4, Appendix B (a copy is attached for convenience). The 2012 BDR Report is filed as evidence with this Application as Exhibit 4, Tab 5, Schedule 2, Appendix E. The API BDR Report was used as the basis for determining the 2010 and 2011 allocations for Appendix 2K (Allocated) and was filed in evidence a Exhibit 4, Tab 5, Schedule 1, Appendix A (EB-2009-0278).

STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION

Prepared for
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August 11, 2008

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1 SUMMARY OF STUDY AND FINDINGS

FortisOntario owns and operates four Ontario electricity distribution business units and a transmission business unit which are regulated by the Ontario Energy Board ("OEB"), as well as unregulated generation assets. To maximize available efficiencies of scale, certain general plant and administrative, general and customer service functions are shared by the business units. In order to prepare appropriate revenue requirements for its 2009 distribution rate applications, Canadian Niagara Power Inc. ("CNPI"), a subsidiary of FortisOntario, conducted a study to allocate the shared costs among its business units. If approved by the OEB, the costs allocated to the regulated distribution business units will become part of the revenue requirement for those business units in 2009.

CNPI requested BDR NorthAmerica Inc. ("BDR") to review the methodology and computations in its study to allocate the shared costs, based on BDR's extensive experience in cost allocation for energy utilities. Based on the information provided by CNPI, BDR has concluded that the approach is reasonable and consistent with acceptable methods of cost allocation for regulated utilities.

2 INTRODUCTION AND SCOPE

FortisOntario is a holding company which owns and operates primarily electricity, transmission and distribution business units in Ontario. Its subsidiary CNPI has three separate distribution territories located in Fort Erie, Port Colborne and Gananoque and transmission assets located in Fort Erie, all of which are licensed and regulated as to rates by the OEB. Another subsidiary, Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric"), operates an electricity distribution system in the City of Cornwall. The Cornwall Electric distribution business is licensed by the OEB.

CNPI is required to obtain the approval of the OEB for the 2009 distribution rates of CNPI in Fort Erie, Gananoque and Port Colborne, and as part of the process, to establish and submit to the OEB cost information in support of the revenue requirements of each of those business units.

Within CNPI, management and specialist staff, and certain key systems and facilities, are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. The location where such facilities and/or staff are concentrated is a result of the history of the CNPI organization. For example, CNPI – Fort Erie was the principle centre of CNPI's distribution and transmission business prior to acquisitions in Port Colborne and Gananoque, and had staff and facilities in place that are now shared with the Port Colborne and Gananoque business units. Examples of these shared functions are executive management, administrative

support functions (finance, human resources, health, safety and environment and information technology) and asset management. These activities support and provide benefits to all of CNPI's regulated business units and to its unregulated business activities.

CNPI retained the services of BDR to perform a review of the methodology used to determine cost responsibility for each distribution service territory, and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. BDR was not requested to comment on the overall level of the costs or on the degree to which operational synergies are achieved by this arrangement, and has not reviewed CNPI's computations.

3 CONSULTANT QUALIFICATIONS

BDR is a leading management consulting firm specializing in advising the electricity industry and related affiliates on strategic, financial and regulatory matters. Our client base includes electric utilities of all ownership categories and interested policy makers/stakeholders such as governments, regulators, consumers, generators, transmission and distribution companies and their affiliates.

BDR's key areas of practice are:

Business and Strategic Planning: BDR staff has completed strategic business plans and options analyses for well over 100 clients in the electricity and related sectors. These plans include consideration of the strengths and weaknesses of the client in a range of business options.

Mergers and Acquisitions: A changing industry requires basic reassessments and decisions to merge and/or acquire businesses and to expand some businesses and exit others. BDR has managed the process of merger, divestment and acquisition of both generation and "wires" facilities in the electricity industry and related affiliates. Key in these assignments is the development of a valuation the enterprise(s).

Regulatory: BDR advises clients who are regulated entities in all aspects of dealing with regulators. This includes supporting applications for mergers and acquisitions, studies in support of rates and revenue requirements, such as cost of capital, cost allocation and working capital analysis. Services include analysis and expert testimony where required.

This assignment for CNPI was carried out by Paula Zarnett, Vice President of BDR. She is a Certified Management Accountant, and has an MBA (Finance) from the University of Calgary. Ms. Zarnett's two decades of cost allocation experience include:

- Fully allocated cost of service studies for natural gas utilities in Manitoba and Alberta;

- Leading a cross-functional team in a one-year project to develop Toronto Hydro's first cost allocation study;
- Membership in the Municipal Electric Association cost allocation sub-committee which studied a generic approach to cost allocation for small, medium and large utilities in Ontario
- Two cost allocation studies for Saint John Energy, a municipal electric utility in New Brunswick;
- A cost allocation and rate design study for Enwave, a district steam system serving a commercial and institutional customer base in Toronto;
- Participation in the OEB's 2003 Cost Allocation Working Group;
- Participation in the OEB's 2005-2006 Cost Allocation Review for electricity distribution utilities;
- Expert review of New Brunswick Power Distribution and Customer Service's cost allocation study in its 2005 application to the New Brunswick PUB.

For the last three years, Ms. Zarnett has presented the Advanced Cost Allocation and Rate Design module at CAMPUT's annual Energy Regulation Course.

4 APPROACH TO THE ASSIGNMENT

Costs directly attributable to each of CNPI's business units, including the distribution services territories of Gananoque, Fort Erie and Port Colborne are recorded to those cost centres and accounts through CNPI's normal accounting procedures. This includes staff and equipment which are shared, but for which the time or usage is recorded directly to a work order. No allocation is necessary for direct costs.

The purpose of this study was to allocate those costs which are shared, and which *cannot be directly attributed to a single business unit*. Although this was not a cost allocation study in the sense of allocation to customer classes, the same generally accepted principles that apply to such allocations in the electricity utility sector can also be applied here.

The shared cost functions to be allocated include primarily general plant and administrative and general expenses, which pose some challenges and generate some differences of expert opinion in distribution cost allocation studies.

The National Association of Regulatory Utility Commissioners ("NARUC") suggests several approaches to allocation of general plant and administrative and general expenses.[1]

[1] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, Washington, D.C., January 1992, pages 105 through 107.

For plant, NARUC suggests the following alternatives:

- Assign the total dollar investment on the same basis as the sum of the allocated investments in direct operating assets;
- Functionalize the investment by estimating its use in each of the direct operating functions (e.g. floor space used in a building); or
- Use of operating labour ratios, assuming that general assets provide facility support to staff in carrying out their work.

For administrative and general expenses, according to NARUC the most detailed method involves classifying each expense type into those which are labour related, those which are plant related, and those which require special analysis for the assignment or application of the beneficiary criteria for assignment. While simple and transparent in concept, this approach involves detailed review of the components of costs within each account, the nature of each activity, and the manner in which the benefits are shared.

For each type of cost, the choice of allocator must be influenced by the data available and/or by the cost and effort associated with gathering the data. It is therefore reasonable to expect that allocation methodologies will be refined over time, as records improve and as more detailed studies are made of cost drivers. As well, changes in organization structure and business processes will affect how costs are incurred, and therefore how they should be shared among business units.

In 2005, BDR conducted a review of the allocation of corporate and shared costs to regulated business units for CNPI, which involved review of the scope and nature of shared services and development of a general methodology, and which was filed with the OEB in EB-2005-0344, EB-2005-0345 and EB-2005-0346 (the "2005 Review"). For purposes of this study, BDR met with the staff of CNPI to document corporate organization and process changes that have taken place since the first review was performed. CNPI staff provided documentation of these changes, which was reviewed. BDR did not independently verify either the financial data or the information as to CNPI's operations provided by CNPI's staff.

This report was therefore prepared on the basis of:

- the discussions with CNPI staff just described;
- BDR's review of the May, 2008 revisions to the "Affiliate Relationships Code for Electricity Distributors and Transmitters", and
- BDR's review of the "Report on Common Corporate Costs Methodology Review" dated May 20, 2005, prepared for Hydro One Networks by R.J. Rudden Associates, and accepted by the OEB as a basis for allocation of Hydro One's common corporate costs between its distribution and transmission functions ("the Rudden Study").

CNPI applied the proposed allocation methodology, and provided BDR with the allocation tables that are attached as an Appendix to this report.

5 METHODOLOGY

5.1 *General Plant*

The shared general plant accounts include:

- information technology hardware and software; and
- transportation and work equipment.

Costs of shared plant to be allocated include depreciation and cost of capital at the allowed rates.

In the 2005 Review, it was determined through discussion with department staff that costs of hardware and software are driven by the number of workstations. It was therefore considered reasonable to allocate these assets in proportion to the staffing level, expressed in full time equivalents (FTEs).

For purposes of this report, more detailed information was compiled as to the uses of the major information systems, and it is now proposed to allocate these systems based on the functions that they support. Finance is the major user of most of the key systems, and these have been allocated following the allocation of costs of the related financial functions (see Section 5.2.5). The land management system is used by the Fort Erie service territory only, and has been assigned 100% to Fort Erie. Information technology assets at the individual workstation level continue to be allocated in proportion to the number of staff.

On review, BDR considers that the use of FTEs continues to be reasonable and consistent with acceptable methods of distribution cost allocation, in respect of costs driven by the number of workstations. BDR also considers that with respect to major systems, including both hardware and software, that are independent of the number of employees accessing such systems, it is appropriate to allocate such costs in a manner consistent with the allocation of other costs of the functions they support.

With regard to transportation and work equipment, these assets were viewed as supporting the functions of installation of new capital plant and the operating and maintenance of existing plant. The transportation and work equipment of CNPI is shared by the distribution business units of Fort Erie and Port Colborne, and by the transmission business unit. The Gananoque distribution business unit does not normally share this equipment for reasons of distance.

In the 2005 Review, these assets were proposed to be allocated to the Fort Erie and Port Colborne distribution business units and to the CNPI transmission business unit, based on each unit's share of the sum of annual capital expenditure and operating and maintenance expenses. For this report, information had become available as to time spent on work for each distribution business unit by the operators of each piece of equipment. The organization of equipment use within CNPI is such that each piece of equipment is consistently used by one employee. It was therefore proposed to use time spent by the operators as the basis of allocation of the costs of the related equipment.

On review, BDR considers this approach to be reasonable, and to represent an improvement over the previous methodology in the allocation of costs of transportation and work equipment.

5.2 *Administrative and General Expenses*

5.2.1 Cost Functions and General Approach

The shared functions include:

- executive
- property and procurement
- regulatory
- finance
- information technology
- health, safety and environment
- human resources management,
- the Board of Directors of CNPI, and
- service centre building expenses (rental and maintenance)

A previously-existing corporate development function has been eliminated since 2005.

As in 2005, all of these cost functions consist primarily of staff salaries, benefits, and the cost of facilities (building, equipment and systems) necessary to support the activities of those staff. Where resource inputs were considered the best available allocator, time spent by staff in the function, expressed in terms of full time equivalents (FTEs) was used. The specific, detailed examination was carried out by CNPI staff, and the results were reviewed by BDR.

5.2.2 Executive

Each executive completed a survey estimating time spent on each of the business units in a representative period. These time estimates in terms of FTEs were used as the basis for

allocation. The costs of administrative support for the executive function were allocated in proportion to the costs of the executives themselves.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation.

5.2.3 Property and Procurement

In the 2005 review an allocation based on the value of purchase orders processed was used to allocate costs to CNPI. Data on the value of purchase orders was not available by individual CNPI business unit, and it was therefore considered reasonable that the value would be proportional, over time, to the value of capital and operating/maintenance spending. In the absence of better data as to time spent by the staff, BDR endorsed these approaches as reasonable, and consistent with acceptable methods of distribution allocation.

For this report, CNPI staff advised that they had made a specific review of the activities of procurement staff. These consist of purchasing agents, storekeepers and vehicle maintenance personnel in Fort Erie and one staff member in Cornwall. This latter employee functions in an integrated manner with Fort Erie staff on behalf of CNPI business units, and is utilized only 25% on behalf of Cornwall Electric, on the basis of recorded time.

On review, BDR considers that time and activity estimates or records of staff represents an improvement in methodology over the prior approach as an allocator consistent with acceptable methods of distribution cost allocation.

5.2.4 Regulatory

The unregulated FortisOntario business units receive no benefit from this function and were excluded from an allocation. However some time is allocated to FortisOntario, as the holding company for the regulated businesses. Based on the judgment of the staff involved, each distribution business unit other than Cornwall Electric and CNPI Transmission have the same regulatory requirements, and have therefore received equal allocations. Cornwall Electric and CNPI transmission presently require a lower level of rate development and regulatory activity. They therefore received reduced allocations based on staff judgment.

In considering this approach, BDR referred to the Rudden study, which documented the direct assignment of regulatory costs between Hydro One's distribution and transmission business units. While this detailed method is certainly most appropriate in the context of Hydro One's scope, depth and variety of regulatory activities, CNPI's regulatory staff represents the regulated business units at regulatory stakeholder events and prepares

required filings. This means that much of the effort applies to the benefit of all CNPI's regulated business units at once. On the basis that regulatory requirements for all CNPI's rate-regulated business units are essentially the same, and that the benefits of specific staff efforts cannot be clearly assigned to individual units, the approach of equal allocations to the three CNPI distribution business units continues, in our view, to be reasonable.

Therefore on review, BDR continues to consider this approach reasonable and consistent with acceptable methods of distribution cost allocation.

5.2.5 Finance

For the 2005 review, CNPI staff developed an overall allocation of finance function FTEs based on estimates by the Finance staff of their time spent in each of the sub-activities comprising the finance function.

For this report, CNPI staff reviewed on a more detailed basis each of the sub-activities that comprise the finance function.

Accounts Payable and Receivable were allocated based on time spent for the business units on these activities.

Payroll was allocated based on the number of employees on payroll for each business unit.

Reporting functions were allocated based on number of reports prepared.

Financial analysis functions were allocated based on units of work prepared.

Supervision was allocated in proportion to the allocation of supervised FTEs in the function.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation.

5.2.6 Information Technology, Health, Safety & Environment, and Human Resources

These functions provide an indirect benefit by serving and supporting staff across the CNPI corporate organization, including both staff representing a direct operating cost and FTEs allocated by the processes described in this report. Therefore, the proportionate direct and allocated FTEs *other than* Information Technology, Health, Safety &

Environment, and Human Resources for each business were used as the basis to allocate these costs.

On review, BDR considers that this approach, as in the 2005 review, is reasonable and consistent with acceptable methods of distribution cost allocation.

5.2.7 Board of Directors CNPI

On the basis of judgment, CNPI staff considers that each business unit within CNPI receives equal absolute level of effort and value from the Board of Directors. These costs have therefore been allocated in equal shares to each of the CNPI business units.

On review, BDR considers that the application of informed judgment is reasonable, and consistent with acceptable methods of distribution cost allocation for a cost of this nature.

5.2.8 Service Centre Rent and Maintenance

CNPI staff advised BDR that the Fort Erie service centre building is owned by FortisOntario and rented by CNPI Fort Erie. Appropriate total rent for the building was determined by an independent appraisal as an estimate of market value. Based on area utilized , the total rent was disaggregated into the office, warehouse and garage components. The warehouse and garage components serve the Fort Erie and Port Colborne and the CNPI transmission business units only, so only those business units received an allocation. The allocation was based on the combined capital and O&M budgets, since inventory in the warehouse and transportation equipment in the garage support capital construction, operating and maintenance activity.

Staff (FTEs) located in the office part of the Fort Erie service center, and their previously determined allocations (or direct assignment) to business units were identified by CNPI staff. Since the office space serves these staff, their allocated or assigned costs were used as an allocator for the office space.

Maintenance costs were in proportion to the allocation of service centre rent.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation.

5.3 *Customer Services*

Billing and related customer services are provided in Fort Erie and Cornwall, and the related costs are allocated to the business units based on the number of customers billed.

Costs of other services are directly assigned, based primarily on the timesheets of employees, but partially by estimates of activity. Supervision is allocated following the allocation of the related employee activity costs.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation.

5.4 *Engineering and Operations*

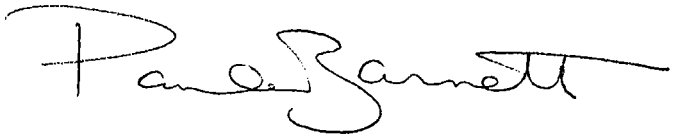
Shared functions of engineering design and operations staff are directly assigned to the business units based on employee time records.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation.

6 AUTHORSHIP AND USE

This report was written and submitted by me, Paula Zarnett, Vice President, BDR NorthAmerica Inc., following a review of information provided to me by CNPI, and is intended for use by CNPI in support of its application to the Ontario Energy Board for approval of 2009 rates and charges.

Dated at Toronto, Ontario, this 11th day of August, 2008.



Paula Zarnett

APPENDIX – ALLOCATION OF FULL-TIME EQUIVALENT STAFF TO BUSINESS UNITS

The following tables resulting from the application of the proposed cost allocation methodology were produced by CNPI and provided to BDR for purposes of this Study.

Distribution of Employees

Department	Employee Count	Company	Allocation CNPI							Fully Allocated	CNPI Dx
			FON	FE	PC	EOP	Tx	CE	Total		
Executive	5	FON	1.00	1.00	0.60	0.30	0.50	1.60	5	Yes	1.90
Transmission Operations	1	CNPI					1.00		1	Yes	0.00
Cornwall	33	CE	0.80			2.00		30.20	33	Yes	2.00
Gananoque	4	CNPI				4.00			4	Yes	4.00
Properrty & Procurement	4	CNPI		2.4	1.2		0.4		4	Yes	3.60
Properrty & Procurement	3	CE		0.14	0.06	0.50	0.05	2.25	3	Yes	0.70
Engineering	7	CNPI		4.60	2.10		0.08	0.22	7	Yes	6.70
Engineering	5	CE		0.10	0.10	1.00		3.80	5	Yes	1.20
T&D Operations	26	CNPI	0.10	14.25	8.25		2.90	0.50	26	Yes	22.50
T&D Operations	3	CE				0.40		2.60	3	Yes	0.40
Regulatory	1	CNPI	0.05	0.21	0.21	0.21	0.21	0.11	1	Yes	0.63
Finance	8	CNPI	0.40	1.60	1.20	0.80	0.80	3.20	8	Yes	3.60
Customer Service	14.5	CNPI		8.70	5.51			0.30	14.50	Yes	14.21
Subtotal	114.5		2.35	33.00	19.23	9.21	5.94	44.78	114.50	Yes	61.44
Health Safety and Environment	2	CNPI	0.04	0.58	0.34	0.16	0.10	0.78	2.00	Yes	1.07
Information Technology	5	CNPI	0.10	1.44	0.84	0.40	0.26	1.96	5.00	Yes	2.68
Information Technology	1	CE						1.00	1	Yes	0.00
Human Resources	1.5	CNPI	0.03	0.43	0.25	0.12	0.08	0.59	1.50	Yes	0.80
Total	124		2.52	35.45	20.66	9.89	6.38	49.10	124.00	Yes	66.00

Distribution of Employees

Department	Employee Count	Company	Allocation CNPI							CNPI Dx
			FON	FE	PC	EOP	Tx	CE	Total	
Executive	5	FON	20%	20%	12%	6%	10%	32%	100%	38%
Transmission Operations	1	CNPI	0%	0%	0%	0%	100%	0%	100%	0%
Cornwall	33	CE	2%	0%	0%	6%	0%	92%	100%	6%
Gananoque	4	CNPI	0%	0%	0%	100%	0%	0%	100%	100%
Properrty & Procurement	4	CNPI	0%	60%	30%	0%	10%	0%	100%	90%
Properrty & Procurement	3	CE	0%	5%	2%	17%	2%	75%	100%	23%
Engineering	7	CNPI	0%	66%	30%	0%	1%	3%	100%	96%
Engineering	5	CE	0%	2%	2%	20%	0%	76%	100%	24%
T&D Operations	26	CNPI	0%	55%	32%	0%	11%	2%	100%	87%
T&D Operations	3	CE	0%	0%	0%	13%	0%	87%	100%	13%
Regulatory	1	CNPI	5%	21%	21%	21%	21%	11%	100%	63%
Finance	8	CNPI	5%	20%	15%	10%	10%	40%	100%	45%
Customer Service	14.5	CNPI	0%	60%	38%	0%	0%	2%	100%	98%
Health Safety and Environment	2	CNPI	2%	29%	17%	8%	5%	39%	100%	54%
Information Technology	5	CNPI	2%	29%	17%	8%	5%	39%	100%	54%
Information Technology	1	CE	0%	0%	0%	0%	0%	100%	100%	0%
Human Resources	1.5	CNPI	2%	29%	17%	8%	5%	39%	100%	54%
Total	124		2%	29%	17%	8%	5%	40%	100%	53%

4. Operating Costs

4.2
Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

(EP)

4. Operating Costs

4.2 Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

58. Ref: Exhibit 4, Tab 1, Schedule 1

Please provide a table in the same level of detail as that shown on page 3 for the actual year to date costs for the most recent period available for 2012. Please provide the corresponding costs for the same period in 2011.

RESPONSE:

Please see the response to OEB interrogatory #36.

(EP)

4. Operating Costs

4.2 Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

59. Ref: Exhibit 4, Tab 2, Schedule 11

a) Please explain what is driving the increase in account 5335 (bad debt expense in 2013.

b) Please explain the extremely low level of bad debt expense shown in 2010.

c) Please explain the new expenditure shown for account 5420 in 2013. Did CNPI have similar expenditures in previous years but the amounts were included in other accounts.

d) Please explain the reductions account 5670 (rent) forecast for 2012 and 2013. Please explain what is being rented in each of 2011, 2012 and 2013.

RESPONSE:

a) The increase in the 2013 Test Year is based on the increasing bad debt expense in Port Colborne since 2009. The collection rules set out in the Distribution System Code require longer payment terms, less security deposit requirements and are expected to increase annual write-offs.

b) Exhibit 4, Tab 3, Schedule 7 explains that the low level of bad debt expense in the 2010 Actual was the result of a previously uncollectible item being collected in 2010. The reversing entry resulted in a lower than expected bad debt expense in the 2010 Actual.

c) This amount is to fund the School Safety Program in Port Colborne, which is run on a four year cycle. In 2009, the program was funded through the OPA community initiative funds.

d) The reductions in OEB account 5670 (rent) for 2012 and 2013 is due to the completion of the Port Colborne lease payments in April 2012.

The amounts in account 5670 are for the Port Colborne lease payment and the rent allocation from Fort Erie for the service centre and offices.

(EP)

4. Operating Costs

4.2 Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

60. Ref: Exhibit 4, Tab 2, Schedule 16

Please show the total costs, by component, associated with the current rates proceeding.

RESPONSE:

Please refer to Appendix 2-H that was provided in response to Board Staff Interrogatory #5.

(SEC)

4. Operating Costs
4.2 Is the proposed CNPI – Port Colborne forecast for total OM&A for the test year appropriate?

11. [Ex.4/3/5/p.1-2]
Please update the table to include a column for 2012 year-to-date.

RESPONSE :

OM & A Detailed Costs Table
Port Colborne

OEB Account	Expense Description	2009 Board Approved	2009 Actual	Variance from 2009 EDR	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge	Variance from 2011 Actual	2013 Test	Variance from 2012 Bridge	Actual June 30, 2012	Variance from 2012 Bridge divided by 2
	Distribution Expenses - Operation													
5005	Operation Supervision and Engineering	33,780	38,985	5,205	39,034	49	71,372	32,338	47,323	(24,049)	50,514	3,191	29,576	5,914
5010	Load Dispatching	78,120	71,417	(6,703)	88,067	16,650	87,701	(366)	93,977	6,276	94,858	880	41,801	(5,188)
5012	Station Buildings and Fixtures Expense	30,000	20,478	(9,522)	25,914	5,437	27,860	1,945	27,000	(860)	27,917	917	9,660	(3,840)
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-	-	-	-	-
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	39,765	17,277	(22,488)	43,634	26,357	40,039	(3,595)	17,718	(22,321)	38,033	20,315	16,094	7,235
5017	Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	4,011	4,011	317	(3,694)	-	(2,006)
5020	Overhead Distribution Lines and Feeders - Operation Labour	-	26,248	26,248	14,338	(11,910)	38,586	24,248	7,412	(31,174)	22,888	15,476	-	(3,706)
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-	-	-	14,890	14,890
5030	Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5035	Overhead Distribution Transformers- Operation	-	-	-	390	390	130	(260)	6,000	5,870	-	(6,000)	-	(3,000)
5040	Underground Distribution Lines and Feeders - Operation Labour	47,568	38,808	(8,760)	46,296	7,488	65,368	19,072	44,669	(20,699)	46,858	2,189	32,369	10,034
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5050	Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	-	2,962	2,962	4,108	1,146	408	(3,700)	2,969	2,561	6,648	3,679	-	(1,485)
5065	Meter Expense	123,887	106,552	(17,335)	119,154	12,602	130,482	11,328	117,377	(13,105)	123,386	6,009	64,755	6,067
5070	Customer Premises - Operation Labour	6,000	-	(6,000)	-	-	-	-	35,666	35,666	33,944	(1,722)	-	(17,833)
5075	Customer Premises - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5085	Miscellaneous Distribution Expense	51,582	37,597	(13,985)	26,096	(11,500)	46,062	19,965	39,966	(6,096)	44,769	4,803	15,519	(4,464)
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
5096	Other Rent	-	-	-	-	-	-	-	-	-	3,000	3,000	-	-
	Distribution Expenses - Operation Total	**410,703**	**360,324**	**(50,379)**	**407,031**	**46,707**	**508,007**	**100,976**	**444,089**	**(63,918)**	**493,132**	**49,043**	**224,664**	**2,619**
	Distribution Expenses - Maintenance													
5105	Maintenance Supervision and Engineering	15,267	23,153	7,886	45,032	21,879	44,489	(543)	52,927	8,438	46,639	(6,288)	24,744	(1,720)
5110	Maintenance of Buildings and Fixtures - Distribution Stations	2,016	17,250	15,234	10,253	(6,997)	10,134	(119)	13,886	3,752	14,365	480	7,879	936
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
5114	Maintenance of Distribution Station Equipment	6,000	3,355	(2,645)	59,247	55,891	30,909	(28,338)	59,988	29,079	65,422	5,434	18,146	(11,848)
5120	Maintenance of Poles, Towers and Fixtures	38,886	13,896	(24,990)	14,869	973	11,147	(3,722)	26,523	15,376	17,503	(9,019)	(8,793)	(22,054)
5125	Maintenance of Overhead Conductors and Devices	96,414	60,500	(35,914)	101,443	40,943	110,772	9,329	106,945	(3,827)	97,236	(9,710)	53,623	150
5130	Maintenance of Overhead Services	102,414	83,434	(18,980)	77,066	(6,368)	86,314	9,248	82,810	(3,503)	79,752	(3,058)	36,829	(4,576)
5135	Overhead Distribution Lines and Feeders - Right of Way	128,046	154,760	26,714	115,510	(39,250)	92,267	(23,243)	125,333	33,066	103,626	(21,707)	54,554	(8,113)
5145	Maintenance of Underground Conduit	-	-	-	-	-	-	-	-	-	-	-	-	-
5150	Maintenance of Underground Conductors and Devices	23,715	2,002	(21,713)	12,333	10,330	7,520	(4,813)	15,227	7,708	9,818	(5,409)	2,596	(5,017)
5155	Maintenance of Underground Services	30,417	4,168	(26,250)	9,589	5,421	8,536	(1,053)	19,262	10,727	11,216	(8,046)	3,296	(6,335)
5160	Maintenance of Line Transformers	23,715	24,028	313	23,592	(436)	24,553	960	27,341	2,789	21,956	(5,385)	11,501	(2,170)
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-	-	-	-	-
5170	Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-	-	-	-	-
5172	Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5175	Maintenance of Meters	78,862	56,440	(22,422)	76,429	19,989	113,011	36,582	112,686	(325)	124,704	12,018	44,241	(12,102)
5178	Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-	-	-	-	-
5195	Maintenance of Other Installations on Customer Premises	-	-	-	65	65	744	679	3,600	2,856	3,600	-	-	(1,800)
	Distribution Expenses - Maintenance Total	**545,753**	**442,988**	**(102,765)**	**545,428**	**102,440**	**540,395**	**(5,033)**	**646,529**	**106,134**	**595,838**	**(50,691)**	**248,615**	**(74,649)**

	Billing and Collection													
5305	Supervision	58,046	25,553	(32,493)	38,455	12,902	32,695	(5,760)	46,355	13,659	63,002	16,648	14,723	(8,455)
5310	Meter Reading Expense	98,433	100,131	1,698	63,618	(36,513)	28,960	(34,658)	40,547	11,586	39,672	(875)	11,299	(8,975)
5315	Customer Billing	157,661	137,063	(20,598)	148,872	11,809	180,176	31,304	184,612	4,436	189,666	5,054	85,735	(6,571)
5320	Collecting	103,910	101,157	(2,754)	132,396	31,239	138,446	6,049	164,774	26,329	158,112	(6,662)	70,481	(11,906)
5325	Collecting- Cash Over and Short	-	-	-	-	-	-	-	-	-	-	-	-	-
5330	Collection Charges	-	-	-	-	-	-	-	-	-	-	-	-	-
5335	Bad Debt Expense	65,945	72,913	6,968	2,912	(70,001)	76,247	73,335	79,400	3,153	92,000	12,600	30,687	(9,013)
5340	Miscellaneous Customer Accounts Expenses	128,523	139,850	11,327	146,902	7,052	175,856	28,955	179,930	4,073	181,754	1,824	86,800	(3,165)
	Billing and Collection Total	**612,519**	**576,667**	**(35,852)**	**533,156**	**(43,511)**	**632,381**	**99,225**	**695,617**	**63,236**	**724,206**	**28,589**	**299,724**	**(48,085)**
	Community Relations													
5405	Supervision	-	-	-	-	-	-	-	-	-	-	-	-	-
5410	Community Relations - Sundry	10,532	7,150	(3,382)	3,304	(3,846)	-	(3,304)	-	-	-	-	-	-
5415	Energy Conservation	-	-	-	-	-	-	-	-	-	-	-	-	-
5420	Community Safety Program	2,500	-	(2,500)	-	-	-	-	-	-	5,000	5,000	-	-
5425	Miscellaneous Customer Service and Informational Expenses	10,666	7,429	(3,237)	6,730	(699)	6,901	172	5,000	(1,901)	8,000	3,000	-	(2,500)
5505	Supervision	-	-	-	-	-	-	-	-	-	-	-	-	-
5510	Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5515	Advertising Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
5660	General Advertising Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
	Community Relations Total	**23,698**	**14,579**	**(9,119)**	**10,034**	**(4,545)**	**6,901**	**(3,132)**	**5,000**	**(1,901)**	**13,000**	**8,000**	**-**	**(2,500)**
	Administrative and General Expenses													
5605	Executive Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5610	Management Salaries and Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-
5615	General Administrative Salaries and Expenses	619,072	612,312	(6,760)	685,247	72,935	691,629	6,382	718,111	26,482	725,458	7,347	348,264	(10,792)
5620	Office Supplies and Expenses	41,976	33,603	(8,373)	33,456	(148)	25,536	(7,920)	35,982	10,447	28,666	(7,317)	12,925	(5,067)
5625	Administrative Expense Transferred/Credit	(260,729)	(260,729)	-	(310,797)	(50,068)	(327,671)	(16,874)	(337,250)	(9,579)	(352,293)	(15,043)	(157,341)	11,284
5630	Outside Services Employed	49,384	51,733	2,349	56,169	4,437	80,841	24,672	60,086	(20,755)	67,932	7,846	103,370	73,327
5635	Property Insurance	55,000	27,025	(27,975)	21,214	(5,810)	19,308	(1,906)	21,100	1,792	18,600	(2,500)	9,271	(1,279)
5640	Injuries and Damages	-	-	-	224	224	-	(224)	-	-	-	-	-	-
5645	Employee Pensions and Benefits	700	-	(700)	-	-	-	-	-	-	-	-	-	-
5650	Franchise Requirements	-	-	-	-	-	-	-	-	-	-	-	-	-
5655	Regulatory Expenses	167,207	229,107	61,900	130,579	(98,528)	133,523	2,944	130,595	(2,928)	129,067	(1,528)	50,691	(14,606)
5665	Miscellaneous General Expenses	-	12,734	12,734	18,747	6,013	7,035	(11,712)	15,000	7,965	11,848	(3,151)	10,912	3,412
5670	Rent	1,222,829	1,153,211	(69,618)	1,155,108	1,897	1,171,108	15,999	470,041	(701,066)	119,673	(350,368)	563,482	328,462
5675	Maintenance of General Plant	191,112	189,143	(1,969)	204,486	15,343	184,936	(19,550)	205,368	20,432	200,589	(4,779)	84,598	(18,086)
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-	-
5695	OM&A Contra Account	-	(1,949)	(1,949)	1,949	3,899	-	(1,949)	-	-	-	-	4,718	4,718
6205	Donations	-	-	-	-	-	6,629	6,629	6,630	1	6,629	(1)	6,629	3,314
	Administrative and General Expenses Total	**2,086,552**	**2,046,190**	**(40,362)**	**1,996,383**	**(49,807)**	**1,992,874**	**(3,509)**	**1,325,663**	**(667,210)**	**956,170**	**(369,493)**	**1,037,519**	**374,688**
	Taxes Other Than Income Taxes													
6105	Taxes Other Than Income Taxes (Note less capital taxes)	70,000	53,880	(16,120)	52,557	(1,323)	52,024	(533)	55,000	2,976	54,100	(900)	120,307	92,807
	Taxes Total	**70,000**	**53,880**	**(16,120)**	**52,557**	**(1,323)**	**52,024**	**(533)**	**55,000**	**2,976**	**54,100**	**(900)**	**120,307**	**92,807**
	Total Operating, Maintenance and Administrative Expenses	**3,749,224**	**3,494,628**	**(254,596)**	**3,544,589**	**49,961**	**3,732,582**	**187,993**	**3,171,898**	**(560,684)**	**2,836,446**	**(335,452)**	**1,930,829**	**344,880**
	Power Supply Expenses													
4705	Power Purchased	11,294,350	11,660,603	366,253	13,015,882	1,355,279	14,508,044	1,492,163	15,746,478	1,238,434	14,036,403	(1,710,075)	7,567,392	(305,847)
4708	Charges-WMS	1,232,393	1,233,978	1,585	1,289,523	55,546	1,376,501	86,977	1,342,015	(34,486)	1,169,833	(172,182)	686,775	15,767
4710	Cost of Power Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
4712	Charges-One-Time	-	-	-	-	-	-	-	-	-	-	-	-	-
4714	Charges-NW	951,737	869,901	(81,835)	1,021,545	151,644	1,126,558	105,012	1,240,466	113,908	1,299,672	59,205	628,301	8,068
4716	Charges-CN	886,093	837,623	(48,470)	905,397	67,774	982,659	77,262	1,064,925	82,266	1,047,004	(17,921)	545,539	13,077
4730	Rural Rate Assistance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
4750	Charges - LV	20,783	25,380	4,597	8,126	(17,254)	20,979	12,853	20,989	10	20,979	(10)	10,979	485
5685	Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-	-	-	-	-
	Power Supply Expenses Total	**14,385,356**	**14,627,485**	**242,129**	**16,240,473**	**1,612,988**	**18,014,740**	**1,774,268**	**19,414,874**	**1,400,133**	**17,573,891**	**(1,840,983)**	**9,438,986**	**(268,451)**
	Total Expenses for Working Capital	**18,134,580**	**18,122,113**	**(12,468)**	**19,785,062**	**1,662,949**	**21,747,322**	**1,962,260**	**22,586,771**	**839,449**	**20,410,337**	**(2,176,434)**	**11,369,815**	**76,430**
	Amortization Expenses													
5705	Amortization Expense - Property, Plant, and Equipment	640,028	421,526	(218,502)	670,717	249,190	126,786	(543,931)	1,056,807	930,022	1,426,900	370,093	359,760	(168,644)
5715	Amortization of Intangibles and Other Electric Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	Amortization Expenses Total	**640,028**	**421,526**	**(218,502)**	**670,717**	**249,190**	**126,786**	**(543,931)**	**1,056,807**	**930,022**	**1,426,900**	**370,093**	**359,760**	**(168,644)**
	Grand Total	**18,774,608**	**18,543,639**	**(230,969)**	**20,455,779**	**1,912,140**	**21,874,108**	**1,418,329**	**23,643,579**	**1,769,471**	**21,837,237**	**(1,806,342)**	**11,729,576**	**(92,214)**

4. Operating Costs

4.3
Are the methodologies used to allocate shared services and other costs appropriate?

(EP)

4. Operating Costs

4.3 Are the methodologies used to allocate shared services and other costs appropriate?

61. Ref: Exhibit 1, Tab 1, Schedule 12

Does FortisOntario or CNPI provide any services to Westario Power Inc., Rideau St. Lawrence Holdings Inc. or Grimsby Power? If so, please quantify and explain how the costs of providing these services are allocated.

RESPONSE:

The response to this question can be found in Exhibit 3, Tab 3, Schedule 2. As noted in this Schedule, IT services are provided only to Grimsby Power Inc. and Westario Power Inc. The explanation of the costs and charges are set out in Schedule 2. The quantification of costs is set out in the Response to OEB IR 22.

(SEC)

4. Operating Costs
4.3 Are the methodologies used to allocate shared services and other costs appropriate?

12. [Ex.4/5/2/E/p.10]
How are costs related to FortisOntario's non-controlling investments in distributors (exp. Rideau St. Lawrence Distribution Inc) tracked and/or allocated?

RESPONSE:

CNPI normally does not share costs with Westario Power, Grimsby Power, or Rideau St. Lawrence with the exception of IT services. Both Westario Power and Grimsby Power share IT services with CNPI. The IT service agreements are described in Exhibit 3 Tab 3 Schedule 2.

CNPI, from time to time, provides assistance to these entities; a separate job work order is created to capture time and costs. For example, in 2009 CNPI assisted Grimsby Power with the smart meter installation project. Also, CNPI annually coordinates a customer satisfaction survey with Westario, and costs are allocated by number of customers.

(VECC)

4. Operating Costs

4.3 Are the methodologies used to allocate shared services and other costs appropriate?

48. Reference: Exhibit 4, Tab 4, Schedule1, Appendix A, page 1 /Exhibit 4, Tab 5, Schedule 2, Appendix E, page 16

a) Please reconcile the FTEs used at page 16 of the BDR Report (Study of Affiliate Service Cost and Cost Allocation), with the FTE's at Appendix A for 2012.

RESPONSE:

a) In response to OEB IR 45, CNPI has prepared and filed a version of Appendix 2K (Allocated) which uses the BDR allocation methodology and which reconciles with page 16 of the BDR Report filed as Exhibit 4, Tab 5, Schedule 2, Appendix E. Please also refer to CNPI response to OEB IR 45.

4. Operating Costs

4.4
Is CNPI – Fort Erie/Gananoque's proposed level of depreciation/amortization expense for the test year appropriate?

(OEB)

Operating Costs

Issue 4.4
Is CNPI – Fort Erie/Gananoque's proposed level of depreciation/amortization expense for the test year appropriate?

41. Ref: E4/T7/S2/Pages1-5: Appendices 2-M

Please confirm that depreciation expenses for the 2013 test year are based on revised useful lives according to the changes in CNPI's accounting policy. Please detail the changes per account.

RESPONSE:

The depreciation expense for 2013 in Exhibit 4 is not based on revised useful lives according to the change in accounting policy. The depreciation expense in Exhibit 11 is based on the revised useful lives. See Appendix 2-CG in the response to OEB question #5 for the detailed changes per account.

(EP)

4. Operating Costs

4.4 Is CNPI – Fort Erie/Gananoque's proposed level of depreciation/amortization expense for the test year appropriate?

62. Ref: Exhibit 11, Tab 1, Schedule 3, Table 3

What is the impact on the 2013 depreciation expense of each of the following?

a) increasing the proposed useful life for Other Meters, PTs & CTs from 30 years to 35 years;

b) increasing the proposed useful life for Small Vehicles from 5 years to 8 years; and,

c) increasing the proposed useful life for Trucks & Buckets from 10 years to 12 years.

RESPONSE:

a) The impact of increasing the proposed useful life for Other Meters, PTs & CTs from 30 years to 35 years on the 2013 depreciation expense would be a decrease of approximately $20,000.

b) The impact of increasing the proposed useful life for Small Vehicles from 5 years to 8 years on the 2013 depreciation expense would be a decrease of approximately $26,500 before allocations, after allocations it would be a decrease of approximately $14,310.

c) The impact of increasing the proposed useful life for Trucks & Buckets from 10 years to 12 years on the depreciation expense would be a decrease of approximately $60,600 before allocations, a decrease of approximately $32,700 after allocations.

4. Operating Costs

4.5
Is CNPI – Port Colborne's proposed level of depreciation/amortization expense for the test year appropriate?

(OEB)

Operating Costs

Issue 4.5 Is CNPI – Port Colborne's proposed level of depreciation/amortization expense for the test year appropriate?

42. Ref: E4/T7/S2/Pages1-5: Appendices 2-M

Please confirm that depreciation expenses for the 2013 test year are based on revised useful lives according to the changes in CNPI's accounting policy and provide a table showing the changes per account.

RESPONSE:

The depreciation expense for 2013 in Exhibit 4 is not based on revised useful lives according to the change in accounting policy. The depreciation expense in Exhibit 11 is based on the revised useful lives. See Appendix 2-CG in the response to OEB question #5 for the detailed changes per account.

(EP)

4. Operating Costs

4.5 Is CNPI – Port Colborne's proposed level of depreciation/amortization expense for the test year appropriate?

63. Ref: Exhibit 11, Tab 1, Schedule 3, Table 3

What is the impact on the 2013 depreciation expense of each of the following:

a) increasing the proposed useful life for Other Meters, PTs & CTs from 30 years to 35 years;

b) increasing the proposed useful life for Small Vehicles from 5 years to 8 years; and,

c) increasing the proposed useful life for Trucks & Buckets from 10 years to 12 years.

RESPONSE:

a) The impact of increasing the proposed useful life for Other Meters, PTs & CTs from 30 years to 35 years on the 2013 depreciation expense would be a decrease of approximately $4,000.

b) The impact of increasing the proposed useful life for Small Vehicles from 5 years to 8 years on the 2013 depreciation expense would be a decrease of approximately $0 before allocations, after allocations it would be a decrease of approximately $6,900.

c) The impact of increasing the proposed useful life for Trucks & Buckets from 10 years to 12 years on the depreciation expense would be a decrease of approximately $0 before allocations, after allocations it would be a decrease of approximately $15,800.

4. Operating Costs

4.6
Is the proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?

(OEB)

Operating Costs

Issue 4.6
Is the Proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?

43. Ref: E4/T8/S2/p.1

Please provide a live excel model of CNPI's tax calculation for FE/EOP.

RESPONSE:

Please refer to the live excel spreadsheet - BoardStaff_IR_43_A_20120718 attached.

TAX CALCULATIONS - FE and EOP

Description	TOTAL CNPI 2009 Actual	TRANSMISSION 2009 Actual	DISTRIBUTION 2009 Actual	TOTAL CNPI 2010 Actual	TRANSMISSION 2010 Actual	DISTRIBUTION 2010 Actual	TOTAL CNPI 2011 Forecast	TRANSMISSION 2011 Forecast	DISTRIBUTION 2011 Forecast	TOTAL CNPI 2012 Regulatory	TRANSMISSION 2012 Forecast	DISTRIBUTION 2012 Regulatory	TOTAL CNPI 2013 Regulatory	TRANSMISSION 2013 Forecast	DISTRIBUTION 2013 Regulatory
Net income(loss) per financial statements	3,024,635	1,323,074	1,701,561	3,121,711	1,504,497	1,617,214	3,005,857	1,555,846	1,450,011	-	-	-	-	-	-
Utility income before taxes	-	-	-	-	-	-	-	-	-	3,450,067	1,236,000	2,214,067	3,893,068	1,215,000	2,678,068
Add:															
Provision for income taxes - current	878,461	395,534	482,927	573,810	275,206	298,604	188,737	100,033	88,704	-	-	-	-	-	-
Provision for income taxes - deferred	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest and penalities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of assets	4,075,289	756,056	3,319,233	4,262,383	762,455	3,499,928	4,452,997	765,727	3,687,270	5,363,652	884,000	4,479,652	6,069,339	901,000	5,168,339
Loss on disposal of assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SHRED	64,716	-	64,716	-	-	-	-	-	-	-	-	-	-	-	-
Donations	27,100	2,389	24,711	-	-	-	-	-	-	-	-	-	-	-	-
Non-deductible meals and entertainment	17,858	1,574	16,284	19,228	2,523	16,705	19,000	2,493	16,507	19,000	2,493	16,507	19,000	2,493	16,507
Reserves from financial statements - EOY	2,357,583	207,811	2,149,772	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918	1,676,000	219,924	1,456,076
Amortization of deferred financing	32,028	12,798	19,230	32,028	10,776	21,252	32,028	7,393	24,635	32,028	7,299	24,729	32,028	7,212	24,816
Amortization of deferred lease costs	58,140	-	58,140	58,140	-	58,140	58,140	-	58,140	19,380	-	19,380	-	-	-
Ontario apprentice and co-op tax credits	4,333	382	3,951	11,274	1,479	9,795	4,000	525	3,475	4,000	525	3,475	4,000	525	3,475
Total Additions	7,515,508	1,376,544	6,138,964	7,115,278	1,335,665	5,779,613	6,609,902	1,119,583	5,490,319	7,260,060	1,133,399	6,126,661	7,800,367	1,131,153	6,669,213
Deduct:															
Gain on disposal of assets per financial statements	51,467	-	51,467	37,802	-	37,802	25,266	-	25,266	-	-	-	-	-	-
Capital cost allowance	4,178,748	554,313	3,624,435	5,102,785	538,668	4,564,117	5,592,886	524,476	5,068,410	5,672,863	680,078	4,992,785	5,960,047	861,745	5,098,302
Cumulative eligible capital deduction	7,781	(0)	7,781	7,237	-	7,237	6,730	-	6,730	6,259	-	6,259	6,259	-	6,259
Reserves from financial statements - BOY	2,386,859	210,392	2,176,467	2,357,583	309,361	2,048,222	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918
Allowance for funds used during construction	116,308	116,308	-	16,338	16,338	-	-	-	-	-	-	-	-	-	-
Capitalized general expense	1,015,195	-	1,015,195	970,154	-	970,154	980,256	-	980,256	1,069,910	-	1,069,910	1,112,726	-	1,112,726
Capital amount expensed for tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Disallowed Ontario apprentice credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred financing costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Deductions	7,756,358	881,013	6,875,345	8,491,899	864,366	7,627,532	8,763,553	807,702	7,955,851	8,604,032	923,489	7,680,542	8,901,032	1,100,827	7,800,205
Taxable Income	2,783,785	1,818,605	965,180	1,745,090	1,975,796	(230,706)	852,206	1,867,727	(1,015,521)	2,106,095	1,445,909	660,186	2,792,403	1,245,327	1,547,076
Corporate tax rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	739,987	330,012	409,975
Grossed Up Taxes															557,789
Calculation of total taxes															
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	887,801	330,012	557,789
Ontario apprentice and co-op tax credits	-	-	-	(9,416)	(1,236)	(8,180)	-	-	-	-	-	-	-	-	-
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777	-	-	-	-	-	-	-	-	-
Total taxes	**1,136,360**	**687,131**	**449,229**	**600,550**	**634,472**	**(33,922)**	**240,748**	**527,633**	**(286,885)**	**558,115**	**383,166**	**174,949**	**887,801**	**330,012**	**557,789**
Tax Rates															
Federal Tax	19.00%	19.00%	19.00%	18.00%	18.00%	18.00%	16.50%	16.50%	16.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Provincial Tax	14.00%	14.00%	14.00%	13.00%	13.00%	13.00%	11.75%	11.75%	11.75%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Total Tax Rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Calculation of Ontario Capital Tax															
Net Paid Up Capital 2006&2007/Total Rate Base 2008&2009	99,498,319	39,756,937	59,741,382	95,514,739	32,135,669	63,379,070									
Less Exemption	2,738,073	1,094,063	1,644,010	2,768,091	931,317	1,836,774									
Taxable Capital/Deemed Taxable Capital	96,760,246	38,662,874	58,097,372	92,746,648	31,204,352	61,542,296									
OCT Rate	0.225%	0.225%	0.225%	0.074%	0.074%	0.074%									
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777									
FORT ERIE AND EOP RATE BASE			45,600,794			47,647,860			48,535,033			50,493,373			52,680,275
% OF TOTAL RATE BASE			76%			75%			75%			73%			72%
TOTAL TAXES			**342,898**			**(25,502)**			**(214,384)**			**127,835**			**400,269**

(EP)

4. Operating Costs

4.6 Is the proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?

64. Ref: Exhibit 4, Tab 8, Schedule 3 &
Exhibit 2, Tab 1, Schedules 5 and 7

a) Please reconcile the additions to the CCA schedules for each year 2009 through 2013 with the additions to gross assets shown in Schedules 5 and 7 of Exhibit 2, Tab 1.

b) Please update the 2011, 2012 and 2013 CCA schedules shown in Exhibit 4, Tab 8, Schedule 3 to reflect the actual CCA additions for 2011.

RESPONSE:

a)

The following is the reconciliation of the additions per the fixed asset continuity schedules to the additions per the CCA schedules.

	2009	2010	2011	2012	2013
Additions per Continuity Schedule					
FE and EOP	5,868,559	3,927,019	4,641,084	6,274,022	5,547,747
PC	2,580,838	755,122	1,076,383	4,673,282	1,903,554
Total additions per Continuity Schedules	8,449,397	4,682,141	5,717,467	10,947,304	7,451,301
Less GEC	1,015,195	970,154	980,256	1,069,910	1,112,725
Less capitalized interest	116,308	16,338	-	-	-
Add smart meters		4,718,457	331,830	233,951	
Less Land				21,867	
Miscellaneaous adjustments	5,413	- 56,238			
Total additions	7,323,307	8,357,868	5,069,041	10,089,479	6,338,576
Additions per CCA schedule	7,323,307	8,357,868	5,069,041	10,089,479	6,338,576
Difference	-	0	0	- 0	- 0

b)

The CCA schedules do not need to be updated because the additions and proceeds of disposition agree to the 2011 tax return. The following is the reconciliation between the additions in the CCA schedules in the rate application and the tax return for 2011.

	2011
Additions per CCA schedule in rate application	5,069,042
Add transmission capital additions	146,157
	5,215,199
Additions per CCA schedule in 2011 tax return	5,215,199
Difference	-

(EP)

4. Operating Costs

4.6 Is the proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?

65. Ref: Exhibit 4, Tab 8, Schedule 3 &
Exhibit 4, Tab 8, Schedule 4

a) Please explain the CCA differences shown for 2010 between that shown in Exhibit 4, Tab 8, Schedule 3, and that shown in Schedule 8 of the 2010 tax return shown in Schedule 4 of Exhibit 4, tab 8.

b) Please file a copy of the 2012 tax return.

RESPONSE:

a)

The following is the reconciliation between the additions in the CCA schedules in the rate application and the tax return for 2010.

	2010
Additions per CCA schedule in rate application	8,357,868
Add transmission capital additions	118,840
	8,476,708
Additions per CCA schedule in 2010 tax return	8,476,708
Difference	0

b) Attached is a copy of CNPI 2011 tax return.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

Business number 87249 8225 RC0002

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	20,430			20,430
2012-02-29	20,430			20,430
2012-03-31	20,430			20,430
2012-04-30	20,430			20,430
2012-05-31	20,430			20,430
2012-06-30	20,430			20,430
2012-07-31	20,430			20,430
2012-08-31	20,430			20,430
2012-09-30	20,430			20,430
2012-10-31	20,430			20,430
2012-11-30	20,430			20,430
2012-12-31	20,423			20,423
Total	245,153			245,153

Quarterly instalment workchart

Date	Quarterly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-03-31				
2012-06-30				
2012-09-30				
2012-12-31				
Total				

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 –	Is the corporation a Canadian-controlled private corporation (CCPC)?	☐ Yes	☒ No
2 –	Did the corporation claim any deduction under the section 125, during either the current or previous year?	☐ Yes	☒ No
3 –	Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?*	☐ Yes	☐ No
4 –	Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?	☐ Yes	☐ No
5 –	Does the corporation have a perfect compliance history in the last 12 months?	☐ Yes	☐ No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

*Consult the Help (F1) for information on the changes relating to years subsequent to 2008.

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	245,153	÷	12	=	20,430	
Monthly instalments required					20,430	
Quarterly tax instalments required	245,153	÷	4	=		

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account? ☐

2nd Monthly instalment base amount

Indicate:	Part I tax		314,117				
	Part VI, VI.1 and XIII.1 tax	+					
	Federal adjustment for amalgamation, winding up or transfer	+					
	Provincial tax, other than Alberta, Québec and Ontario	+					
	Ontario tax	+	295,707				
	Provincial adjustment for amalgamation, winding up or transfer	+					
	Total	=	609,824	÷ 12	=	50,819	**A**
1/12 of estimated current year credits (M below /12)					–		
				Each of the first two instalment payments	=	50,819	**B**
Total tax from N below			245,153				
Amount B above x 2		–	101,638				
		=	143,515	÷ 10	=	14,352	
				Each of the remaining ten instalment payments	=	14,352	

2nd Quarterly instalment base amount

Indicate:	Part I tax		314,117				
	Part VI, VI.1 and XIII.1 tax	+					
	Federal adjustment for amalgamation, winding up or transfer	+					
	Provincial tax, other than Alberta, Québec and Ontario	+					
	Ontario tax	+	295,707				
	Provincial adjustment for amalgamation, winding up or transfer	+					
	Total	=	609,824	÷ 4	=	152,456	**A**
1/4 of estimated current year credits (M below /4)					–		
				The first instalment payment	=		**B**
Total tax from N below			245,153				
Amount B above		–					
		=	245,153	÷ 3	=	81,718	
				Each of the remaining three instalment payments	=		

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷	12	=	
Monthly instalments required					
Quarterly tax instalments required		÷	4	=	

Instalment base calculation

Federal tax		1st instalment base method		Estimated tax method	
Taxable income		867,866			
Calculation of tax payable					
Federal part I tax		329,789			
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	329,789	=		A
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+	86,787	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	99,805	+		
Logging tax credit	+		+		
Investment tax credit per Schedule 31	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	186,592	=		B
Federal tax summary					
Total part I tax payable (A minus B)		143,197			C
Part VI tax	+		+		D
Part VI.1 tax	+		+		E1
Part XIII.1 tax	+		+		E2
Parts I, VI, VI.1 and XIII.1 **Total**	=	143,197	=		F
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	143,197	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	143,197	=		G
Provincial tax					
Provincial/territorial tax, other than Alberta, Québec and Ontario	+		+		H
Ontario tax					
Income tax	101,956				
Capital tax +					
Corporate minimum tax paid (credited) +					
Special additional tax on life insurance corporations +					
Total Ontario tax* =	101,956 ▶	101,956	+		I
Harmonized provincial tax (H + I) **Total harmonized provincial tax**	=	101,956	=		J
Provincial adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	101,956	=		
Provincial adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total provincial tax after adjustments	=	101,956	=		K
Total of tax before refundable credits** (G + K)	=	245,153	=		L

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund				
Dividend refund	+		+	
Federal capital gains refund	+		+	
Provincial and territorial capital gains refund	+		+	
NRO allowable refund per Schedule 26	+		+	
Tax withheld at source	+		+	
Other estimated credits	+		+	
Total estimated current year credits	=		=	**M**
Instalment base amount (L – M)		245,153		**N**

* Ontario tax corresponds to the amount before the application of specified Ontario tax credits.

** For instalments payable the amount on line G is not added to line L unless it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation			
Canadian Niagara Power Inc.			
Business Number	Tax year ▶	From Y M D	To Y M D
87249 8225 RC0002		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	867,866
Part I tax payable (line 700)	143,197
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	87,233
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, KING (Last name in block letters) GLEN (First name in block letters) Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2012-06-27 (Date (yyyy/mm/dd)) _____ (Signature of an authorized signing officer of the corporation) (905) 871-0330 (Telephone number)

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: FortisOntario Inc. Electronic filer number: I3522

Privacy Act, Personal Information Bank number CRA PPU 047

T183 CORP (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business Number (BN) 001 87249 8225 RC0002

Corporation's name

002 Canadian Niagara Power Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . . 010 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018.)

011 1130 Bertie Street

012

City	Province, territory, or state
015 Fort Erie	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 L2A 5Y2

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . . 020 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028.)

021 c/o

022 1130 Bertie Street

023 P.O. Box 1218

City	Province, territory, or state
025 Fort Erie	026 ON
Country (other than Canada)	**Postal code/Zip code**
027	028 L2A 5Y2

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . . 030 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038.)

031 1130 Bertie Street

032

City	Province,territory, or state
035 Fort Erie	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 L2A 5Y2

040 **Type of corporation at the end of the tax year**

1 ☐ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☒ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 _____ YYYY MM DD

To which tax year does this return apply?

Tax year start	Tax year-end
060 2011-01-01 YYYY MM DD	061 2011-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . . 065 _____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . . 064 1 Yes ☐ 2 No ☒

subsection 249(3.1)? . . . . . 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . . 070 1 Yes ☐ 2 No ☒

Amalgamation? . . . . . 071 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . . 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used . . . . . 079 _____

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 _____

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	X	54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Energy Distribution and Transmission	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible (YYYY MM DD)	294		
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	867,866	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			867,866	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360	867,866	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			867,866	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** _____ A

Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** _____ B

Business limit (see notes 1 and 2 below) . . . . . **410** _____ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C _____ x **415** ***** _____ D = ... _____ E
11,250

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** _____ F

Small business deduction

Amount A, B, C, or F, whichever is the least _____ x 17 % = ... **430** _____ G

Enter amount G on line 1 on page 7.

***** 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

****** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

******* General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

******** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

******* Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*							A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27						B	
Amount QQ from Part 13 of Schedule 27						C	
Personal service business income**					432	D	
Amount used to calculate the credit union deduction from Schedule 17						E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least						F	
Aggregate investment income from line 440 on page 6***						G	
Total of amounts B to G					▶		H
Amount A **minus** amount H (if negative, enter "0")							I
Amount I	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year		x	9 %	=	J
Amount I	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	K
Amount I	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	L
Amount I	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year		x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M . . . . . N

Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.

** For tax years beginning after October 31, 2011.

*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)						867,866	O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27						P	
Amount QQ from Part 13 of Schedule 27						Q	
Personal service business income*					434	R	
Amount used to calculate the credit union deduction from Schedule 17						S	
Total of amounts P to S					▶		T
Amount O **minus** amount T (if negative, enter "0")						867,866	U
Amount U	867,866 x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year		x	9 %	=	V
Amount U	867,866 x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	W
Amount U	867,866 x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	= 99,805	X
Amount U	867,866 x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year		x	13 %	=	Y

General tax reduction – Total of amounts V to Y . . . . . 99,805 Z

Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . **440** _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . _____

Deduct:

Foreign investment income from Schedule 7 . . . . . **445** _____ x 9 1 / 3 % = _____

(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") . . . . . _____ C

Taxable income from line 360 on page 3 . . . . . _____

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Foreign non-business income tax credit from line 632 on page 7 . . . _____ x 25/9* 25 / 9 = _____

Foreign business income tax credit from line 636 on page 7 . . . . . _____ x 1(0.38 - X**) 3.77358 = _____

_____ ▶ _____

x 26 2 / 3 % = _____ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . _____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . . **450** _____ F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . **460** _____

Deduct: Dividend refund for the previous tax year . . . . . **465** _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____

Total Part IV tax payable from Schedule 3 . . . . . _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . **480** _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . . **485** _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . . _____

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % **550** 329,789 A

Recapture of investment tax credit from Schedule 31 . . . . . **602** B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 i

Taxable income from line 360 on page 3 . . . . . _____

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Net amount . . . . . _____ ▶ _____ ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** C

Subtotal (**add** lines A to C) 329,789 D

Deduct:

Small business deduction from line 430 on page 4		1	
Federal tax abatement	**608**	86,787	
Manufacturing and processing profits deduction from Schedule 27	**616**		
Investment corporation deduction	**620**		
Taxed capital gains **624** _____			
Additional deduction – credit unions from Schedule 17	**628**		
Federal foreign non-business income tax credit from Schedule 21	**632**		
Federal foreign business income tax credit from Schedule 21	**636**		
General tax reduction for CCPCs from amount N on page 5	**638**		
General tax reduction from amount Z on page 5	**639**	99,805	
Federal logging tax credit from Schedule 21	**640**		
Federal qualifying environmental trust tax credit	**648**		
Investment tax credit from Schedule 31	**652**		
Subtotal		186,592 ▶	186,592 E

Part I tax payable – Line D **minus** line E . . . . . 143,197 F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	143,197
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		143,197

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	87,233	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		87,233 ▶	87,233
Total tax payable	770		230,430 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	271,000	
Total credits	890	271,000 ▶	271,000 B

Refund code 894 1 Overpayment 40,570

Balance (line A **minus** line B) -40,570

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

Certification

I, 950 KING (Last name in block letters) 951 GLEN (First name in block letters) 954 Chief Financial Officer (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-27 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (905) 871-0330 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No ☒

958 HARRY CLUTTERBUCK (Name in block letters) 959 (905) 871-0330 (Telephone number)

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact Harry Clutterbuck
Telephone number (905) 871-0330

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2011-01-31	INSTALLMENT REMITTANCE	55,000
2011-02-28	INSTALLMENT REMITTANCE	27,000
2011-03-31	INSTALLMENT REMITTANCE	27,000
2011-04-29	INSTALLMENT REMITTANCE	27,000
2011-05-31	INSTALLMENT REMITTANCE	27,000
2011-06-30	INSTALLMENT REMITTANCE	27,000
2011-07-29	INSTALLMENT REMITTANCE	27,000
2001-08-31	INSTALLMENT REMITTANCE	27,000
2011-09-30	INSTALLMENT REMITTANCE	27,000
	INSTALLMENT REMITTANCE	
	INSTALLMENT REMITTANCE	
	INSTALLMENT REMITTANCE	

Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	271,000	**A**
Total instalments credited to the taxation year per T9	271,000	**B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	21,386,930	20,437,874
	Total tangible capital assets	2008	+	126,607,800	121,079,905
	Total accumulated amortization of tangible capital assets	2009	–	48,222,841	44,232,468
	Total intangible capital assets	2178	+	18,207,792	17,410,300
	Total accumulated amortization of intangible capital assets	2179	–	7,094,021	6,397,068
	Total long-term assets	2589	+	2,896,980	5,782,106
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	113,782,640	114,080,649
Liabilities					
	Total current liabilities	3139	+	10,516,235	11,859,495
	Total long-term liabilities	3450	+	65,936,538	64,897,145
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	76,452,773	76,756,640
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	37,329,867	37,324,009
	Total liabilities and shareholder equity	3640	=	113,782,640	114,080,649
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	13,429,867	13,424,009

***** Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	74,503,800	70,310,224
	Cost of sales	8518	–	60,103,988	55,549,176
	Gross profit/loss	8519	=	14,399,812	14,761,048
	Cost of sales	8518	+	60,103,988	55,549,176
	Total operating expenses	9367	+	11,329,629	11,125,314
	Total expenses (mandatory field)	9368	=	71,433,617	66,674,490
	Total revenue (mandatory field)	8299	+	74,628,212	70,370,011
	Total expenses (mandatory field)	9368	–	71,433,617	66,674,490
	Net non-farming income	9369	=	3,194,595	3,695,521
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	3,194,595	3,695,521
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	188,737	573,810
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	3,005,858	3,121,711

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	1 Yes	X	2 No	
Is the accountant connected* with the corporation?	097	1 Yes		2 No	X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

	198	
Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes		2 No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

	110	
Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	1 Yes	X	2 No	

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes?	104	1 Yes		2 No	X
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes		2 No	X
Is contingent liability information mentioned in the notes?	106	1 Yes	X	2 No	
Is information regarding commitments mentioned in the notes?	107	1 Yes	X	2 No	

Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes		2 No	X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

T2 BAR CODE RETURN

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002

Tax Year Start: 2011-01-01

Tax Year End: 2011-12-31

Financial Statements

Canadian Niagara Power Inc.

December 31, 2011

INDEPENDENT AUDITORS' REPORT

To the Shareholder of

Canadian Niagara Power Inc.

We have audited the accompanying financial statements of Canadian Niagara Power Inc., which comprise the balance sheet as at December 31, 2011 and 2010, and January 1, 2010, and the statements of income, retained earnings and cash flows for the years ended December 31, 2011 and 2010, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

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

Auditors' responsibility

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

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

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

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

Opinion

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

In our opinion, the financial statements present fairly, in all material respects, the financial position of Canadian Niagara Power Inc. as at December 31, 2011 and 2010, and January 1, 2010, and the results of its operations and its cash flows for the years ended December 31, 2011 and 2010 in accordance with Canadian accounting standards for private enterprises.

Toronto, Canada, Chartered Accountants
February 29, 2012. Licensed Public Accountants

1. FIRST-TIME ADOPTION OF ACCOUNTING STANDARDS FOR PRIVATE ENTERPRISES AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

Canadian Niagara Power Inc. [the "Corporation"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out in a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business

of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. FIRST-TIME ADOPTION OF ACCOUNTING STANDARDS FOR PRIVATE ENTERPRISES

These financial statements are the first financial statements which the Corporation has prepared in accordance with the new accounting standards for private enterprises ["ASPE"], as per Part II of the CICA Handbook - Accounting, which constitutes generally accepted accounting principles for non -publicly accountable enterprises in Canada. In preparing its opening balance sheet as at January 1, 2010 [the "Transition Date"], the Corporation has applied Section 1500, First-time adoption, retrospectively [other than the permitted exemptions noted below] using the following four principles such that it has:

" Recognized all assets and liabilities whose recognition is required by GAAP;
" Not recognized items as assets or liabilities if GAAP does not permit such recognition;
" Reclassified items recognized previously as one type of asset, liability or component of equity, but are now recognized as a different type of asset, liability or component of equity;
" Applied GAAP in measuring all recognized assets and liabilities.

The Corporation has consistently applied the same accounting policies in its opening ASPE balance sheet at January 1, 2010 and throughout all periods presented as if these policies had always been in effect. Upon adoption, there was no transitional financial impact on the financial statements of the Corporation.

Exemptions elected upon transition

Section 1500 provides a number of elective exemptions from the retrospective adoption of ASPE. The Corporation has elected to use the following transition exemption:

[i] Related party transactions - Section 3840, Related Party Transactions, specifies that certain related party transactions shall be measured at the carrying amount and some at the exchange amount. The Corporation has elected not to restate assets and liabilities related to transactions with related parties when the related party transaction occurred prior to the Transition Date.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

The transmission and distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of

return on rate-base, plus a recovery of all allowable distribution costs of CNPI.

The current rates of CNPI are based upon the 2009 Rate Orders issued by the OEB for new rates effective May 1, 2009, plus two Third-Generation Incentive Rate Mechanism ["IRM"] electricity distribution rate applications for 2010 and 2011, as described below. As part of the 2009 Rate Orders, the distribution rates of Fort Erie and Gananoque were harmonized.

In 2009, the Corporation filed IRM electricity distribution rate applications in Fort Erie, Gananoque and Port Colborne, for rates effective May 1, 2010. The OEB issued its Decisions and Orders related to these applications on April 16, 2010. The Decisions and Orders resulted in average increases of 1.4% in Fort Erie and 6.6% in Port Colborne and an average decrease of 5.6% in Gananoque. Core distribution rates were increased based on an inflation factor of 1.3% offset by a productivity factor of 0.72% and stretch factors ranging from 0.4% to 0.6%. Other factors influencing final rates were the discontinuance of certain rate riders from the 2009 applications, the disposition of December 31, 2008 regulatory deferral accounts, the final stage of transition to the 60/40 debt/equity structure and capital tax adjustments.

On November 8, 2010, the Corporation filed IRM electricity distribution rate applications for Fort Erie, Gananoque and Port Colborne for rates effective May 1, 2011. Core distribution rates were increased based on an inflation factor 1.3%, offset by the productivity factor of 0.72% and a stretch factor for Port Colborne of 0.6% and a stretch factor for Fort Erie and Gananoque of 0.4%. The 2011 price cap index was therefore -0.02% for Port Colborne and 0.18% for Fort Erie and Gananoque. The IRM maintained a return on equity of

8.01% with a 60/40 debt equity structure. The OEB issued its Decision and Order for Port Colborne on March 28, 2011 which resulted in an average decrease of 4.0% for the average residential customer. The decrease was primarily the result of reductions in deferral account rate riders. The OEB issued its final Decision and Order for Fort Erie and Gananoque on April 14, 2011 which resulted in an average increase of 3.8% for the average residential customer in Gananoque; this increase was primarily the result of increases in deferral account rate riders and an increase to the smart meter funding adder. The Decision and Order resulted in an average increase of 1.7% for the average residential customer in Fort Erie; this increase was primarily the result of increases to the smart meter funding adder.

The Corporation filed two IRM electricity distribution rate applications on November 10, 2011 for Fort Erie, Gananoque and Port Colborne. A harmonized IRM application was filed for Fort Erie and Gananoque. The OEB has yet to publish the applicable inflation factor and productivity and stretch factors for 2012. It is anticipated that the numbers will be available in the first quarter of 2012. The third generation IRM maintains a return on equity of 8.01% with a 60/40 debt equity structure. As at December 31, 2011, no Decisions and Orders on these applications have been issued by the OEB.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2011 were $80 [2010 - $105].

Utility capital assets

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Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 3.3% [2010 - 3.4%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

General expenses capitalized ["GEC"] are capitalized overhead costs which are not directly attributable to specific utility capital assets but relate to the

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Corporation's overall capital program. GEC is permitted by the OEB's Distribution Rate Handbook and Accounting Procedures Handbook. In the absence of rate regulation, utility overhead costs which are not directly attributable to construction activity would not be capitalized. GEC is allocated over the constructed utility capital assets and amortized based on the rate applicable to these assets.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of ASPE.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of

the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as of January 1, 2004] over the assigned value of identifiable net assets acquired.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Operating lease

The Corporation has entered into an operating lease, which expires in 2012, with the City of Port Colborne, whereby the Corporation operates and maintains the City of Port Colborne's electricity distribution assets and provides service to the residents of Port Colborne. The Corporation recognizes all revenue relating to this agreement in operating revenue and records the cost of the lease as operating lease expense. At the end of the lease term, the Corporation has the option to purchase the assets at a pre-determined amount.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to

customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2011 is $4,432 [2010 - $4,642].

Translation of foreign currencies

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans and change in measurement date accounting policy

The Corporation accrues its obligations under employee benefit plans. The cost of pension benefits and other retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of discount rates, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are valued at fair value. The excess of any cumulative net actuarial gain (loss) over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of active employees.

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Prior to 2011, the Corporation measured the plan assets and accrued benefit obligations for both its pension benefit plans and other retirement plans as of September 30th of each year. In 2011, the Corporation changed the measurement date to December 31st in order to align with the reporting date of its parent company, Fortis Ontario Inc. This change had no significant impact on the plan assets and pension obligations.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. Effective January 1, 2009, the Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE 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 revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as

adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2011		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,616	11,210	11,406
Distribution	90,825	29,342	61,483
Other	13,167	7,671	5,496
	126,608	48,223	78,385

	2010		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,556	10,606	11,950
Distribution	86,356	26,754	59,602
Other	12,167	6,872	5,295
	121,079	44,232	76,847

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	January 1, 2010		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,356	10,005	12,351
Distribution	81,675	24,207	57,468
Other	11,438	6,097	5,341
	115,469	40,309	75,160

The amounts above include assets under construction, which are not subject to amortization, of $3,131 [2010 - $2,906; January 1, 2010 - $3,866].

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2011		
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	7,912	4,787	3,125
Land and transmission rights	6,827	2,249	4,578
Other	255	58	197
	14,994	7,094	7,900

	2010		
		Accumulated	Net book

	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	7,162	4,265	2,897
Land and transmission rights	6,779	2,080	4,699
Other	255	52	203
	14,196	6,397	7,799

January 1, 2010			
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	5,730	3,891	1,839
Land and transmission rights	6,730	1,913	4,817
Other	255	45	210
	12,715	5,849	6,866

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

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Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan			Other retirement plan		
	2011	2010	January 1, 2010	2011	2010	January 1, 2010
	$	$	$	$	$	$
Accrued benefit obligation						
Balance, beginning of year	12,999	12,022	11,970	5,024	4,042	4,160
Current service cost	322	282	263	93	65	78
Interest cost	669	757	764	275	269	279
Benefits paid	(1,103)	(897)	(913)	(310)	(159)	(293)
Actuarial losses (gains)	413	835	(62)	340	807	(182)
Balance, end of year	13,300	12,999	12,022	5,422	5,024	4,042
Plan assets						
Fair value, beginning of year	11,871	11,737	11,357	--	--	--
Actual return on plan assets	1,372	166	746	--	--	--
Contributions	962	985	631	--	--	--
Benefits paid	(1,103)	(897)	(914)	--	--	--
Plan expenses	(112)	(120)	(83)	--	--	--
Fair value, end of year	12,990	11,871	11,737	--	--	--
Funded status - deficit	(310)	(1,128)	(285)	(5,422)	(5,024)	(4,042)

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Unamortized amounts

Actuarial losses 2,477 2,900 1,567 1,140 767 4

Prior service costs 29 33 38 44 87 137

Transitional obligation 187 206 224 ? -- --

Accrued benefit asset (liability) 2,383 2,011 1,544 (4,238)

(4,170) (3,901)

As per note 1, the measurement date for the plan assets and the accrued benefit obligation is December 31, 2011. The effective date of the most recent actuarial valuation was as of December 31, 2009 and the next required valuation for funding purposes is as of December 31, 2012.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

%

Canadian equity funds 14

U.S. equity funds 13

EAFE equity funds 12

Canadian fixed income funds 59

Cash and short-term investments 2

Pension benefit plan Other retirement plan

2011 2010 2011 2010

$ $ $ $

Significant assumptions used

Discount rate	5.10%	5.20%	5.25%	5.40%
Expected long-term rate of return on plan assets	6.25%	6.25%	-	-
Rate of compensation increase	4.00%	4.00%	-	-
Assumed health care trend rate	-	-	4.50%	4.50%
Average remaining service period of active employees [years]	8	9	17	17

Net benefit expense for the year				
Current service cost	420	385	93	65
Interest cost	669	757	275	269
Expected return on plan assets	(724)	(711)	-	-
Actuarial losses	203	64	15	-
Amortization of transitional obligation and past service costs	23	23	44	44
Net benefit expense	591	518	427	378

The total expense for the Corporation's defined contribution pension plan for the year amounted to $212 [2010 - $200]. The pension cost associated with the OMERS plan was $108 [2010 - $72].

5. INCOME TAXES

The provision for income taxes (recovery) consists of the following:

2011	2010
$	$

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Current income taxes 189 574
Future income taxes
Future income taxes transferred to regulatory assets 424
(424) 376
(376)
189 574

As per note 1, during the year, the Corporation recorded $424 in regulatory assets and a corresponding offset to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

	2011	2010	January 1, 2010
	$	$	$
Future tax liabilities (assets)			
Utility capital assets	4,013	3,641	3,286
Employee future benefits	(464)	(539)	(589)
Other assets	60	83	112
Net future tax liabilities	3,609	3,185	2,809

6. RELATED PARTY TRANSACTIONS

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During the year, the Corporation entered into the following transactions with related parties:

	2011	2010
	$	$
Receipts		
Administrative services to		
FortisOntario Inc.	111	147
Cornwall Street Railway, Light and Power Company Limited	1,532	1,483
Algoma Power Inc.	881	-
Reimbursement of expenses paid on behalf of and services provided to		
FortisOntario Inc.	287	292
Fortis Properties Corporation	227	242
Algoma Power Inc.	1,014	1,452
Westario Power Holdings Inc.		
Grimsby Power Inc.		
Cornwall Street Railway, Light and Power Company Limited	273	
151		
431	228	
85		
94		
Payments		
Purchased power from Fortis Properties Corporation	1,370	848
Management fees paid to FortisOntario Inc.	725	831
Rent paid to FortisOntario Inc.	485	485

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Interest expense paid to (received from)
Cornwall Street Railway, Light and Power Company Limited (2) (7)
FortisOntario Inc.
Algoma Power Inc. 1,352
13 1,329
-
Reimbursement for expenses paid on behalf of and services
provided from
FortisOntario Inc. 3,778 3,769
Newfoundland Power Inc. 5 -

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

At December 31, the amounts due to (from) related parties are as follows:

2011 2010 January 1, 2010
$ $ $

Due to (from) FortisOntario Inc. 3,073 4,047 (16)
Due to Fortis Inc. ? ? 23
Due to Fortis Properties Corporation 156 260 93
Due to Cornwall Street Railway, Light and Power Company Limited
?
?
671

Due from Westario Power Holdings Inc.

Due from Grimsby Power Inc.

Due from Algoma Power Inc. (18)

(63)

(355) (65)

(37)

(169) (23)

-

(131)

2,793 4,036 617

Promissory notes due to parent 20,000 20,000 20,000

A promissory note of $15,000 due to the parent company bears interest at a rate of 6.13% and is payable on demand. A promissory note of $5,000 due to the parent company bears interest at a rate of 7.62% and is payable on demand. There are no specific terms of repayment for these notes.

7. LONG-TERM DEBT

Long-term debt consists of the following:

2011 2010 January 1, 2010

$ $ $

7.092% senior unsecured notes due August 14, 2018 30,000 30,000

30,000

Unamortized debt issue costs (211) (243) (275)

29,789 29,757 29,725

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,128 [2010 - $2,128].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2011, the accumulated amortization was $269 [2010 - $237; January 1, 2010 - $205].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2011	2010
	$	$
Amortization of utility capital assets	4,068	3,997
Amortization of contributions in aid of construction	(310)	(283)
Amortization of intangible assets and other	695	548
	4,453	4,262

10. STATEMENTS OF CASH FLOWS

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The net change in non-cash working capital balances related to operations consists of the following:

	2011	2010
	$	$
Accounts receivable	1,525	805
Due to related parties	(1,243)	3,419
Materials and supplies	(53)	(1)
Prepaid expenses	45	(260)
Accounts payable and accrued liabilities	(100)	21
Regulatory assets/liabilities	94	(915)
Income taxes payable/receivable	219	232
	487	3,301

Supplemental cash flow information:

	2011	2010
	$	$
Interest paid	3,742	3,375
Income taxes paid	271	940

11. COMMITMENTS AND CONTINGENCIES

The Corporation has a commitment under an operating lease agreement for the lease of the electricity distribution assets of Port Colborne Hydro Inc.

["PCHI"]. Future minimum lease payments under the agreement, which runs until April 2012, total $489.

In April 2011, the Corporation provided The Corporation of the City of Port Colborne and PCHI an irrevocable written notice of its election to exercise the purchase option under the current operating lease agreement, at the purchase option price of $6,900 on April 15, 2012. The purchase constitutes the sale of the remaining assets of PCHI to the Corporation. This purchase will be subject to OEB approval under Section 86 of the Ontario Energy Board Act.

12. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk: Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk: Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk: Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance

sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	As at December 31, 2011 $
Not past due	8,588
Past due 0-30 days	348
Past due 31-60 days	71
Past due 61 days and over	139
	9,146
Less allowance for doubtful accounts	145
	9,001

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds.

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These funds are a result of allowable rate-regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation is a subsidiary of Fortis Inc., a large investor-owned utility, which has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. The recent volatility in the global markets may increase the cost of and timing of issuance of long-term capital by Fortis Inc. and its subsidiaries.

To mitigate any liquidity risk, the Corporation has committed revolving credit facilities and letters of credit facilities totalling $8,000, of which approximately $3,700 is unused. The revolving credit facilities and letters of credit facilities are renewed on an annual basis. The following summary outlines the credit facilities of the Corporation:
?

	2011	2010
	$	$
Total credit facilities	8,000	8,000
Letters of credit outstanding	(4,282)	(4,282)
Credit facilities available	3,718	3,718

The facilities are collateralized by a general security agreement covering all assets of the Corporation and are guaranteed by the Corporation and its parent

company. The credit facilities bear interest at the bankers' acceptance rate plus 2.0% in the case of bankers' acceptances, and the bank's prime lending rate plus 1.0% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2011:

	< 1 year	1-3 years	4-5 years	> 5 years	Total
	$	$	$	$	$
Accounts payable and accrued liabilities	6,789	?	?	?	6,789
Government remittances payable	253	?	?	?	253
Customer deposits	338	215	128	?	681
Promissory notes due to parent	?	?	?	20,000	20,000
Long-term debt	?	?	?	30,000	30,000
	7,380	215	128	50,000	57,723

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2011 and 2010 are nil.

13. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital

structure reflected in the utility's customer rates. Effective May 1, 2010, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2011 Actual		2010 Actual		As at January 1, 2010	
	$	%	$	%	$	%
Debt	50,000	57	50,000	57	50,000	57
Equity	37,330	43	37,324	43	37,202	43
	87,330	100	87,324	100	87,202	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 65% to 70% of their respective capital structures as defined in the agreements. As at December 31, 2011, the Corporation was in compliance with its debt covenants.

14. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power

itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet dates. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

In 2006, the Government of Ontario committed to install a smart electricity meter in all Ontario homes and small businesses by the end of 2010. The Corporation will be eligible to recover all prudent and reasonable costs that arise from this smart metering initiative. These costs represent incremental operating, administrative and capital costs directly related to smart meters.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition which may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates, as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as

permitted by the regulators.

	2011	2010	January 1, 2010	Remaining rebate
	$	$	$	period
Current regulatory assets				
Amounts approved in current rates	570	664	67	1 year
Long-term regulatory assets				
Retail settlement and other variance accounts	3,634	3,984	5,675	1.5+ years
Smart meter variance account	4,001	3,711	2,076	2+ years
Future taxes to be recovered from customers	3,609	3,185	2,809	life of assets
Other	50	117	343	
	11,294	10,997	10,903	
Current regulatory liabilities				
Amounts approved in current rates	?	?	318	
Long-term regulatory liabilities				
Retail settlement and other variance accounts	2,552	3,040	1,921	2+ years
Other	498	54	171	2+ years
	3,050	3,094	2,092	

15. SEGMENTED INFORMATION

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

[a] Earnings

2011

Fort Erie & Eastern Ontario Power

Port Colborne

Fort Erie

	Distribution	Distribution	Transmission	Total
	$	$	$	$
Operating revenue	43,258	23,483	4,769	71,510
Purchased power	30,894	18,015	-	48,909
Operating expenses	4,955	3,041	1,712	9,708
Operating lease	-	1,523	-	1,523
Amortization	3,212	475	766	4,453
Operating earnings	4,197	429	2,291	6,917
Interest expense	(2,426)	(661)	(635)	(3,722)
Income taxes	(105)	16	(100)	(189)
Net earnings	1,666	(216)	1,556	3,006

2010

	Fort Erie & Eastern Ontario Power	Port Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Operating revenue	41,405	21,789	4,770	67,964
Purchased power	29,381	16,240	-	45,621
Operating expenses	5,036	2,859	1,577	9,472
Operating lease	-	1,523	-	1,523
Amortization	3,048	452	762	4,262
Operating earnings	3,940	715	2,431	7,086
Interest expense	(2,196)	(542)	(652)	(3,390)
Income taxes	(272)	(27)	(275)	(574)
Net earnings	1,472	146	1,504	3,122

[b] Utility capital assets

2011			
Fort Erie & Eastern Ontario Power Distribution	Port Colborne Distribution	Fort Erie Transmission	Total
$	$	$	$
Cost	87,138	16,854	22,616	126,608
Accumulated amortization	34,414	2,599	11,210	48,223
	52,724	14,255	11,406	78,385

2010		
Fort Erie & Eastern Ontario	Port	

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

	Power Distribution	Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$
Cost	82,812	15,711	22,556	121,079
Accumulated amortization	31,527	2,099	10,606	44,232
	51,285	13,612	11,950	76,847

	January 1, 2010 Fort Erie & Eastern Ontario Power Distribution	Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$
Cost	78,902	14,211	22,356	115,469
Accumulated amortization	28,684	1,620	10,005	40,309
	50,218	12,591	12,351	75,160

16. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2011 financial statements.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

Assets – lines 1000 to 2599

1000	2,953,722	1060	9,001,325	1066	60,373
1120	155,950	1480	8,813,082	1484	402,478
1599	21,386,930	1600	242,399	1740	126,365,401
1741	-48,222,841	2008	126,607,800	2009	-48,222,841
2010	14,993,790	2011	-7,094,021	2012	3,214,002
2178	18,207,792	2179	-7,094,021	2422	2,383,044
2424	513,936	2589	2,896,980	2599	113,782,640

Liabilities – lines 2600 to 3499

2620	7,042,203	2860	2,793,461	2961	680,571
3139	10,516,235	3140	30,000,000	3240	3,608,661
3300	20,000,000	3320	8,089,509	3321	4,238,368
3450	65,936,538	3499	76,452,773		

Shareholder equity – lines 3500 to 3640

3500	23,900,000	3600	13,429,867	3620	37,329,867
3640	113,782,640				

Retained earnings – lines 3660 to 3849

3660	13,424,009	3680	3,005,858	3700	-3,000,000
3849	13,429,867				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	74,503,800	**8089**	74,503,800	**8094**	112,589
8210	25,266	**8231**	-13,443	**8299**	74,628,212

Cost of sales – lines 8300 to 8519

8320	49,018,616	**8450**	11,085,372	**8518**	60,103,988
8519	14,399,812				

Operating expenses – lines 8520 to 9369

8520	392,483	**8523**	45,581	**8570**	694,898
8590	220,239	**8670**	3,758,098	**8690**	157,915
8710	3,723,757	**8860**	1,376,809	**9180**	278,515
9200	79,938	**9220**	601,396	**9367**	11,329,629
9368	71,433,617	**9369**	3,194,595		

Farming revenue – lines 9370 to 9659

9659	0

Farming expenses – lines 9660 to 9899

9898	0

Extraordinary items and taxes – lines 9970 to 9999

9970	3,194,595	**9990**	188,737	**9999**	3,005,858

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end (Year Month Day)
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				3,005,858 A
Add:				
Provision for income taxes – current		101	188,737	
Amortization of tangible assets		104	3,758,098	
Amortization of intangible assets		106	694,898	
Non-deductible meals and entertainment expenses		121	22,791	
Reserves from financial statements – balance at the end of the year		126	1,855,324	
	Subtotal of additions		6,519,848 ▶	6,519,848
Other additions:				
Financing fees deducted in books		216	32,028	
Miscellaneous other additions:				
600 Amortization of deferred lease costs		290	58,140	
604 Ontario Co-op tax credit	11,819			
Ontario Apprenticeship	2,904			
	Total 14,723	294	14,723	
	Subtotal of other additions	199	104,891 ▶	104,891
	Total additions	500	6,624,739 ▶	6,624,739
Deduct:				
Gain on disposal of assets per financial statements		401	25,266	
Capital cost allowance from Schedule 8		403	5,476,909	
Cumulative eligible capital deduction from Schedule 10		405	6,730	
Reserves from financial statements – balance at the beginning of the year		414	2,158,415	
	Subtotal of deductions		7,667,320 ▶	7,667,320
Other deductions:				
Miscellaneous other deductions:				
701 Capitalized General Expense deducted for Tax		391	1,095,411	
704				
	Total	394		
	Subtotal of other deductions	499	1,095,411 ▶	1,095,411
	Total deductions	510	8,762,731 ▶	8,762,731
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				867,866

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Canada

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
867,866		867,866	101,956

Ontario basic income tax (from Schedule 500) 270 101,956

Deduct: Ontario small business deduction (from schedule 500) 402

Subtotal 101,956 ▶ 101,956 A6

Add:

Surtax re Ontario small business deduction (from Schedule 500) 272

Ontario additional tax re Crown royalties (from Schedule 504) 274

Ontario transitional tax debits (from Schedule 506) 276

Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) 101,956 C6

Deduct:

Ontario resource tax credit (from Schedule 504) 404

Ontario tax credit for manufacturing and processing (from Schedule 502) 406

Ontario foreign tax credit (from Schedule 21) 408

Ontario credit union tax reduction (from Schedule 500) 410

Ontario transitional tax credits (from Schedule 506) 414

Ontario political contributions tax credit (from Schedule 525) 415

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 101,956 E6

Deduct: Ontario research and development tax credit (from Schedule 508) 416

Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") 101,956 F6

Deduct: Ontario corporate minimum tax credit (from schedule 510) 418

Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") 101,956 G6

Add:

Ontario corporate minimum tax (from Schedule 510) 278

Ontario special additional tax on life insurance corporations (from Schedule 512) 280

Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies) 282

Subtotal ▶ H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 101,956 I6

Deduct:

Ontario qualifying environmental trust tax credit 450

Ontario co-operative education tax credit (from Schedule 550) 452 11,819

Ontario apprenticeship training tax credit (from Schedule 552) 454 2,904

Ontario computer animation and special effects tax credit (from Schedule 554) 456

Ontario film and television tax credit (from Schedule 556) 458

Ontario production services tax credit (from Schedule 558) 460

Ontario interactive digital media tax credit (from Schedule 560) 462

Ontario sound recording tax credit (from Schedule 562) 464

Ontario book publishing tax credit (from Schedule 564) 466

Ontario innovation tax credit (from Schedule 566) 468

Ontario business-research institute tax credit (from Schedule 568) 470

Other Ontario tax credits . . . . . .

Subtotal 14,723 ▶ 14,723 J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) 290 87,233 K6

(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 87,233

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) **200**	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) **201**	3 Cost of acquisitions during the year (new property must be available for use)* **203**	4 Net adjustments** **205**	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) **207**	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** **211**	7 Reduced undepreciated capital cost	8 CCA rate % **** **212**	9 Recapture of capital cost allowance (line 107 of Schedule 1) **213**	10 Terminal loss (line 404 of Schedule 1) **215**	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** **217**	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) **220**
1.	1		35,114,785			0		35,114,785	4	0	0	1,404,591	33,710,194
2.	1b	Building > Mar 18, 2007	205,052	3,693		0	1,847	206,898	6	0	0	12,414	196,331
3.	2		1,843,689			0		1,843,689	6	0	0	110,621	1,733,068
4.	3		68,015			0		68,015	5	0	0	3,401	64,614
5.	8		463,414	23,073		0	11,537	474,950	20	0	0	94,990	391,497
6.	10		1,348,358	123,025		6,827	58,099	1,406,457	30	0	0	421,937	1,042,619
7.	12		674,844	749,588		0	374,794	1,049,638	100	0	0	1,049,638	374,794
8.	13	Leasehold Improvements		289,975		0	144,988	144,987	NA	0	0	28,998	260,977
9.	45	Computers > 22-03-04 & < 19-(	25,825			0		25,825	45	0	0	11,621	14,204
10.	46	System Supervisory processing e		247		0	124	123	30	0	0	37	210
11.	47		22,539,179	3,728,862		21,175	1,853,844	24,393,022	8	0	0	1,951,442	24,295,424
12.	50	Computers > Mar 18, 2007	555,667	296,736		0	148,368	704,035	55	0	0	387,219	465,184
		Totals	62,838,828	5,215,199		28,002	2,593,601	65,432,424				5,476,909	62,549,116

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	0928418 BC Ltd		83980 6106 RC0001	3					
2.	1228158 Ontario Limited		88706 8690 RC0001	3					
3.	16006059 Ontario Inc.		86184 9107 RC0001	3					
4.	52905 Newfoundland and Labrador		80392 9546 RC0001	3					
5.	605555 BC LTD.		89351 3416 RC0001	3					
6.	630319 BC Ltd.		87011 0616 RC0001	3					
7.	Algoma Power Inc.		82249 4290 RC0001	3					
8.	Atlantic Equipment & Power (Turks	TC	NR	3					
9.	BC Gas (Argentina) S.A.		NR	3					
10.	BC Gas (Malaysia) SDN. BHD.		NR	3					
11.	BC Gas International (BVI) Inc.		NR	3					
12.	BC Gas International (BVI-II) Inc.		NR	3					
13.	BC Gas International (BVI-III) Inc.		NR	3					
14.	BC Gas International (Middle East)		89059 8022 RC0001	3					
15.	BC Gas International Projects Ltd.		86892 1644 RC0001	3					
16.	Belize Electric Company Limited	BZ	NR	3					
17.	Belize Electricity Limited	BZ	NR	3					
18.	Caribbean Utilities Company, Ltd.	KY	NR	3					
19.	Cornwall Street Railway Light and P		12090 6839 RC0001	3					
20.	ESI Power-Walden Corporation		12628 4249 RC0001	3					
21.	Fortis Alberta Holdings Inc.		86921 0203 RC0001	3					
22.	Fortis Belize Limited	BZ	NR	3					
23.	Fortis Cayman Inc.	KY	NR	3					
24.	Fortis Energy (Bermuda) Ltd.	BM	NR	3					
25.	Fortis Energy Cayman Inc.	KY	NR	3					
26.	Fortis Energy Corporation		10386 4443 RC0001	3					
27.	Fortis Energy International (Belize)	BZ	NR	3					
28.	Fortis Generation East GP Inc		83966 8308 RC0001	3					
29.	Fortis Generation Inc		83967 1096 RC0001	3					
30.	Fortis Hydro Corporation		NR	3					
31.	Fortis Inc.		10185 2416 RC0001	3					
32.	Fortis Properties Corporation		89693 2449 RC0001	3					
33.	Fortis TCI Limited	TC	NR	3					
34.	Fortis US Energy Corporation	US	NR	3					
35.	Fortis West Inc.		87470 8209 RC0001	3					
36.	FortisAlberta Inc.		86929 4520 RC0001	3					
37.	FortisBC Alternative Energy Services		81144 5873 RC0001	3					
38.	FortisBC Energy (Vancouver Island)		12174 3074 RC0001	3					
39.	FortisBC Energy (Whistler) Inc.		89138 9652 RC0001	3					
40.	FortisBC Energy Inc.		10043 1592 RC0002	3					
41.	FortisBC Holdings Inc.		10534 9740 RC0004	3					
42.	FortisBC Huntington Inc.		12974 2870 RC0001	3					
43.	FortisBC Inc.		10564 5642 RC0001	3					

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
44.	FortisBC Pacific Holdings Inc.		87170 9101 RC0001	3					
45.	FortisBC Storage Inc.		86014 6588 RC0001	3					
46.	FortisOntario District Heating Inc.		89329 1740 RC0001	3					
47.	FortisOntario Inc.		10076 8985 RC0003	1					
48.	FortisUS Holdings Nova Scotia Limit		82872 6091 RC0001	3					
49.	FortisUS Inc.	US	NR	3					
50.	Inland Energy Corp.		11960 8529 RC0001	3					
51.	Inland Pacific Energy Services		10249 0554 RC0001	3					
52.	Maritime Belize Limited	BZ	NR	3					
53.	Maritime Electric Cayman Inc.	KY	NR	3					
54.	Maritime Electric Company, Limited		12111 9879 RC0001	3					
55.	Mt. Hayes (GP) Ltd.		84888 3914 RC0001	3					
56.	Newfoundland Electric Company Lir		12748 1059 RC0001	3					
57.	Newfoundland Energy Cayman Inc.	KY	NR	3					
58.	Newfoundland Industries Limited		87536 2774 RC0001	3					
59.	Newfoundland Power Inc.		10386 4831 RC0001	3					
60.	Terasen Gas Holdings Inc.		86602 7832 RC0001	3					
61.	Terasen International Inc.		13237 5346 RC0001	3					
62.	The Gananoque Water Power Comp		10521 4068 RC0001	3					
63.	Waneta Expansion General Partner		84815 4001 RC0001	3					
64.	West Kootenay Power Ltd.		89427 8670 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 96,146 A

Add:

Cost of eligible capital property acquired during the taxation year **222**

Other adjustments **226**

Subtotal (line 222 plus line 226) x 3 / 4 = B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") ▶ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 96,146 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 96,146 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 96,146

less amount from line 249

Current year deduction . . . . . 96,146 x 7.00 % = **250** 6,730 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 6,730 ▶ 6,730 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 89,416 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988	400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)	401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3	
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4	
Line 3 minus line 4 (if negative, enter "0")		▶	5	
Total of lines 1, 2 and 5			6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7	
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8	
Subtotal (line 7 plus line 8)	409	▶	9	
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5 _____ x 1 / 2 =				Q
Line P minus line Q (if negative, enter "0")				R
Amount R _____ x 2 / 3 =				S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)	410			

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Deferred Pension Asset GL 150	-2,011,185		-968,063	-596,204	-2,383,044
2	Deferred Post Retirement Bene	4,169,600		426,600	357,832	4,238,368
	Reserves from Part 2 of Schedule 13					
	Totals	2,158,415		-541,463	-238,372	1,855,324

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 54

LOW RATE INCOME POOL (LRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

On: 2011-12-31

- Use this schedule to calculate the balance of the low rate income pool (LRIP) at any time in the tax year if you are a corporation resident in Canada that is:
  - a corporation **other** than a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC); or
  - a corporation that elects under subsection 89(11) not to be a CCPC.
- When an eligible dividend was paid or there was a change in the LRIP balance in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Sections and subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Did the corporation elect not to be a CCPC under subsection 89(11) ITA for the current year or a prior year or did it revoke this election in the current year*? . . . . . ☐ Yes ☒ No

* If the corporation revoked its election in the current year when filing Form T2002, this election will still be valid for the current year, but will cease to apply as of the end of the year.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

Change in the type of corporation

1. Was the corporation a CCPC during its preceding taxation year? . . . . . ☐ Yes ☒ No
2. Corporations that ceased to be a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 2 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

3. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 3 is yes, answer questions 4 and 5. If the answer is no, go to question 6.
4. Was one or several of the predecessor corporations a CCPC or a DIC during the taxation year that ended immediately before the amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 4 is yes, complete Part 5.
5. Was one or several of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 5 is yes, complete Part 5 (line R).

Winding-up

6. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to Part 1.
7. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 6.
8. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 6 (line R).

Part 1 – Calculation of low rate income pool (LRIP)

LRIP at the end of the immediately previous tax year (enter "0" for the first tax year ending in 2006)			**100**	
Income for the credit union deduction (amount E in Part 3 of Schedule 17 of the previous year if the corporation was **not** a CCPC in the previous tax year, otherwise enter "0")	**120**			
Aggregate investment income of a corporation that has elected under subsection 89(11) not to be a CCPC (line 440 of the T2 return of the previous tax year)	**140**			
Subtotal (**add** lines 120 and 140)		x 80 % =	**150**	
Investment corporation deduction (line 620 of the T2 return of the previous tax year)		x 4 =	**160**	
Subtotal (**add** lines 100, 150, and 160)			**190**	

Part 2 – Calculation of LRIP and excessive eligible dividend designations during the tax year

Complete this part if you paid an eligible dividend in the tax year.

	200 Date* (yyyy/mm/dd)	210 Total dividends** receivable in the year up to but not including the date on line 200 that are deductible under section 112	220 Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC***	230 Subtotal (**add** lines 190, 210, and 220)	240 Total dividends**** payable in the year up to but not including the date on line 200	250 Total of excessive eligible dividend designations made up to, but not including the date on line 200
1.	2011-12-21					

	260 LRIP as of the date on line 200 (line 230 **minus** the total of line 240 and line 250)	270 Total eligible dividends paid on the date on line 200	280 Excessive eligible dividend designation (**lesser** of lines 260 and 270)
1.		3,000,000	

Total excessive eligible dividend designations in the tax year (total of all amounts in column 280) . . A
Enter this amount on line B on Schedule 55.

* Enter on line 200 each date where:
- an eligible dividend was paid in the year; or
- an adjustment was made as a result of an amalgamation or the wind-up of a subsidiary or on ceasing to be a CCPC (by an election or otherwise).

** taxable dividends from a corporation resident in Canada (other than eligible dividends)

*** Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC. Total the adjustments for this date and enter on line 220.

**** includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1)).

Part 3 – LRIP closing balance calculation

Amount on line 190 of Part 1 . . . . . A

Dividends** receivable in the tax year that are deductible under section 112 (Amount on line 210 in the last row (last date) of the chart in Part 2) . . . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends receivable in the year that are deductible under section 112 (hereinafter: "dividends other than eligible dividends receivable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends receivable other than eligible dividends receivable. . . . . .

Total dividends** receivable in the tax year that are deductible under section 112 . . . . . **510**

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC*** (Amount on line 220 in the last row (last date) of the chart in Part 2) . . . . .

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC*** if no eligible dividend has been paid in the tax year . . . . . .

Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC*** **520**

Subtotal (**add** lines 510 and 520) ▶ B

Subtotal (**add** lines A and B) C

Total dividends**** payable in the tax year (Amount on line 240 in the last row (last date) of the chart in Part 2) . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends payable in the year (hereinafter: "dividends other that eligible dividends payable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends paid other than eligible dividends paid. . . . . .

Total dividends**** payable in the tax year **540**

Total excessive eligible dividend designations in the tax year (line A from Part 2) . . . . . D

Subtotal (**add** lines 540 and D) ▶ E

LRIP at the end of the tax year (line C **minus** line E) (if negative enter "0") **590**

** Taxable dividends from a corporation resident in Canada (other than eligible dividends).

*** Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC.

**** Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1)).

Part 4 – Worksheet for adjustment when a corporation ceases to be a CCPC or DIC

Adjustment date . . . . . _____

Complete this part if the corporation is neither a CCPC nor a DIC in this tax year but was a CCPC or a DIC in the previous tax year.
This adjustment to the LRIP can be made at any time in the tax year.
Keep a copy of this calculation for your records in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of the previous tax year . . . . . _____ D
The corporation's cash on hand immediately before the end of the previous tax year . . . . . _____ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . . _____
Net capital losses . . . . . _____
Farm losses . . . . . _____
Restricted farm losses . . . . . _____
Limited partnership losses . . . . . _____
Subtotal _____ ▶ _____ F

Subtotal (**add** lines D, E, and F) _____ G

All of the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous tax year . . . . . _____ H
Paid up capital of all of the corporation's issued and outstanding shares of capital stock immediately before the end of its previous tax year . . . . . _____ I

All of the corporation's reserves deducted in its previous tax year . . . . . _____ J
Is the corporation a private corporation? . . . . . ☐ Yes ☒ No
The corporation's capital dividend account immediately before the end of its previous tax year if the corporation is **not** a private corporation in the current tax year . . . . . _____ K
The corporation's general rate income pool (GRIP) at the end of its previous tax year . . . . . _____ L
Eligible dividends paid in the previous tax year . . . . . _____ 3
Excessive eligible dividend designations made in the previous tax year . . . . . _____ 4
Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . . _____ ▶ _____ M

Subtotal (line L **minus** line M) _____ ▶ _____ N

Subtotal (**add** lines H, I, J, K, and N) _____ ▶ _____ O

Adjustment for a corporation that ceases to be a CCPC or DIC (line G **minus** line O) (if negative, enter "0") . . . . . _____ T

Part 5 – Worksheet for adjustment when a corporation is formed as a result of an amalgamation

nb. 1

Adjustment date . . . . . _____

Complete this part if the corporation was formed as a result of an amalgamation or merger of two or more corporations, one of which is a taxable Canadian corporation. Complete a separate worksheet for **each** predecessor.

This adjustment to the LRIP can be made at any time in the tax year.

The last tax year was its tax year that ended immediately before the amalgamation.

Keep a copy of this calculation for your records, in case we ask to see it later.

For a predecessor corporation that was a CCPC or a DIC in its tax year that ended immediately before the amalgamation

Cost amount to the predecessor of all property immediately before the end of its last tax year . . . . . _____ D

The predecessor's cash on hand immediately before the end of its last tax year . . . . . _____ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . . _____

Net capital losses . . . . . _____

Farm losses . . . . . _____

Restricted farm losses . . . . . _____

Limited partnership losses . . . . . _____

Subtotal _____ ▶ _____ F

Subtotal (**add** lines D, E, and F) _____ G

All of the predecessor's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . . _____ H

Paid up capital of all the predecessor's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . . _____ I

All of the predecessor's reserves deducted in its last tax year . . . . . _____ J

The predecessor's capital dividend account immediately before the end of its last tax year if the new corporation is **not** a private corporation . . . . . _____ K

The predecessor's general rate income pool (GRIP) at the end of its last tax year . . . . . _____ L

Eligible dividends paid in its last tax year . . . _____ 3

Excessive eligible dividend designations made in its last tax year . . . . . _____ 4

Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . . _____ ▶ _____ M

Subtotal (line L **minus** line M) _____ ▶ _____ N

Subtotal (**add** lines H, I, J, K, and N) _____ ▶ _____ O

Adjustment for a CCPC or DIC predecessor corporation (line G **minus** line O) (if negative, enter "0") . . . . . _____ P

For a predecessor corporation that was neither a CCPC nor a DIC in its tax year that ended immediately before the amalgamation

LRIP at the end of its last tax year . . . . . _____ Q

Adjustment for a predecessor corporation involved in an amalgamation (**add** lines P and Q) . . . . . _____ T

Calculate amount T for **each** predecessor.

Part 6 – Worksheet for adjustment when a corporation has wound-up a subsidiary

nb. 1

Adjustment date . . . . . _____

Complete this part if the corporation is the parent corporation and has, in the year, received all or substantially all of the assets on dissolution or wind-up of a subsidiary. Complete a separate worksheet for **each** subsidiary involved in the wind-up.

This adjustment to the LRIP can be made at any time in the tax year that is on or after the end of the subsidiary's last tax year.

The last tax year for the subsidiary was its tax year during which its assets were distributed to the parent on the wind-up.

Keep a copy of this calculation for your records in case we ask to see it later.

For a subsidiary corporation that was a CCPC or a DIC in its last tax year

Cost amount to the subsidiary of all property immediately before the end of its last tax year . . . . . _____ D

The subsidiary's cash on hand immediately before the end of its last tax year . . . . . _____ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . . _____

Net capital losses . . . . . _____

Farm losses . . . . . _____

Restricted farm losses . . . . . _____

Limited partnership losses . . . . . _____

Subtotal _____ ▶ _____ F

Subtotal (**add** lines D, E, and F) _____ G

All of the subsidiary's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . . _____ H

Paid up capital of all the subsidiary's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . . _____ I

All the subsidiary's reserves deducted in its last tax year . . . . . _____ J

The subsidiary's capital dividend account immediately before the end of its last tax year if the parent is **not** a private corporation . . . . . _____ K

The subsidiary's general rate income pool (GRIP) at the end of its last tax year . . . . . _____ L

Eligible dividends paid in its last tax year . . . _____ 3

Excessive eligible dividend designations made in its last tax year . . . . . _____ 4

Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . . _____ ▶ _____ M

Subtotal (line L **minus** line M) _____ ▶ _____ N

Subtotal (**add** lines H, I, J, K, and N) _____ ▶ _____ O

Adjustment for a CCPC or DIC subsidiary (line G **minus** line O) (if negative, enter "0") . . . . . _____ P

For a subsidiary corporation that was neither a CCPC nor a DIC in its last tax year

LRIP at the end of its last tax year . . . . . _____ Q

Adjustment for a subsidiary involved in a wind-up (**add** lines P and Q) . . . . . _____ T

Calculate amount T for **each** subsidiary.

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	100		
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3		3,000,000	
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200	3,000,000	
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year		365	x	14.00 %	=	% A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181	365	x	12.00 %	=	5.95068 % A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184	365	x	11.50 %	=	5.79726 % A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ▶ 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 867,866 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . . 101,956 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 2

Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return) . . . . . x = 3

Enter the least of amounts 1, 2, and 3 (line 4 on page 4 of the T2 return) . . . . . D

Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** 867,866.00 / 867,866 = ... 1.00000 E

Amount D x amount E a

Ontario taxable income (amount B from Part 2) 867,866 b

Ontario small business income (lesser of amount a and amount b) . . . . . F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year ____ / 365 x 8.50 % = % G1

Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year 181 / 365 x 7.50 % = 3.71918 % G2

Number of days in the tax year after June 30, 2011 / Number of days in the tax year 184 / 365 x 7.00 % = 3.52877 % G3

OSBD rate for the year (total of rates G1 to G3) . . . . . 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) . . . . . H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . . ▶ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year = ____ / 365 x 4.25 % = ____ % M

Amount L **multiplied by** % on line M = ... N

Amount N ____ x Ontario small business income (amount F from Part 3) / 500,000 ____ / 500,000 = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . . P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . . Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.24795 % = R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . . S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17		T
Deduct:		
Ontario adjusted small business income (amount S from Part 5)		U
Subtotal (amount T **minus** amount U) (if negative, enter "0")		V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %	
Amount V **multiplied** by the OSBD rate for the year		W
Ontario domestic factor (amount E from Part 3)	1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)		Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	113,782,640
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	232,244,791
Total assets (total of lines 112 to 116)		346,027,431
Total revenue of the corporation for the tax year **	142	74,628,212
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	109,268,621
Total revenue (total of lines 142 to 146)		183,896,833

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	3,005,858
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	188,737		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		188,737 ▶		188,737 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	3,194,595

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 3,194,595

Deduct:

CMT loss available (amount R from Part 7) . . . . . _____

Minus: Adjustment for an acquisition of control * . . . . . **518** _____

Adjusted CMT loss available . . . . . _____ ▶ _____ C

Net income subject to CMT calculation (if negative, enter "0") **520** 3,194,595

Amount from line 520 3,194,595 x (Number of days in the tax year before July 1, 2010 _____ / Number of days in the tax year 365) x 4 % = _____ 1

Amount from line 520 3,194,595 x (Number of days in the tax year after June 30, 2010 365 / Number of days in the tax year 365) x 2.7 % = 86,254 2

Subtotal (amount 1 **plus** amount 2) 86,254 3

Gross CMT: amount on line 3 above x OAF ** **540** 86,254

Deduct:

Foreign tax credit for CMT purposes *** . . . . . **550** _____

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . . 86,254 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 101,956

Net CMT payable (if negative, enter "0") . . . . . _____ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** _____ = _____

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . . G

Deduct:

CMT credit expired * **600**

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . . ▶ **620**

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) **650**

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) . . . . .

SAT payable (amount O from Part 6 of Schedule 512) . . . . .

Subtotal ▶ K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . . **670** L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 101,956 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 86,254 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 86,254 6

Subtotal (if negative, enter "0") 15,702 ▶ 15,702 N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 101,956

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) 14,723

Subtotal (if negative, enter "0") 87,233 ▶ 87,233 O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . . **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	0928418 BC Ltd	83980 6106 RC0001	0	0
2	1228158 Ontario Limited	88706 8690 RC0001	1	0
3	16006059 Ontario Inc.	86184 9107 RC0001	0	0
4	52905 Newfoundland and Labrador	80392 9546 RC0001	0	0
5	605555 BC LTD.	89351 3416 RC0001	0	0
6	630319 BC Ltd.	87011 0616 RC0001	0	0
7	Algoma Power Inc.	82249 4290 RC0001	96,584,551	37,418,908
8	Atlantic Equipment & Power (Turks & Caicos)	NR	0	0
9	BC Gas (Argentina) S.A.	NR	0	0
10	BC Gas (Malaysia) SDN. BHD.	NR	0	0
11	BC Gas International (BVI) Inc.	NR	0	0
12	BC Gas International (BVI-II) Inc.	NR	0	0
13	BC Gas International (BVI-III) Inc.	NR	0	0
14	BC Gas International (Middle East)	89059 8022 RC0001	0	0
15	BC Gas International Projects Ltd.	86892 1644 RC0001	0	0
16	Belize Electric Company Limited	NR	0	0
17	Belize Electricity Limited	NR	0	0
18	Caribbean Utilities Company, Ltd.	NR	0	0
19	Cornwall Street Railway Light and Power Company Li	12090 6839 RC0001	57,266,308	67,529,995
20	ESI Power-Walden Corporation	12628 4249 RC0001	0	0
21	Fortis Alberta Holdings Inc.	86921 0203 RC0001	0	0
22	Fortis Belize Limited	NR	0	0
23	Fortis Cayman Inc.	NR	0	0
24	Fortis Energy (Bermuda) Ltd.	NR	0	0
25	Fortis Energy Cayman Inc.	NR	0	0
26	Fortis Energy Corporation	10386 4443 RC0001	0	0
27	Fortis Energy International (Belize)	NR	0	0
28	Fortis Generation East GP Inc	83966 8308 RC0001	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Fortis Generation Inc	83967 1096 RC0001	0	0
30	Fortis Hydro Corporation	NR	0	0
31	Fortis Inc.	10185 2416 RC0001	0	0
32	Fortis Properties Corporation	89693 2449 RC0001	0	0
33	Fortis TCI Limited	NR	0	0
34	Fortis US Energy Corporation	NR	0	0
35	Fortis West Inc.	87470 8209 RC0001	0	0
36	FortisAlberta Inc.	86929 4520 RC0001	0	0
37	FortisBC Alternative Energy Services Inc.	81144 5873 RC0001	0	0
38	FortisBC Energy (Vancouver Island) Inc.	12174 3074 RC0001	0	0
39	FortisBC Energy (Whistler) Inc.	89138 9652 RC0001	0	0
40	FortisBC Energy Inc.	10043 1592 RC0002	0	0
41	FortisBC Holdings Inc.	10534 9740 RC0004	0	0
42	FortisBC Huntington Inc.	12974 2870 RC0001	0	0
43	FortisBC Inc.	10564 5642 RC0001	0	0
44	FortisBC Pacific Holdings Inc.	87170 9101 RC0001	0	0
45	FortisBC Storage Inc.	86014 6588 RC0001	0	0
46	FortisOntario District Heating Inc.	89329 1740 RC0001	21,558	0
47	FortisOntario Inc.	10076 8985 RC0003	78,317,484	4,319,718
48	FortisUS Holdings Nova Scotia Limited	82872 6091 RC0001	0	0
49	FortisUS Inc.	NR	0	0
50	Inland Energy Corp.	11960 8529 RC0001	0	0
51	Inland Pacific Energy Services	10249 0554 RC0001	0	0
52	Maritime Belize Limited	NR	0	0
53	Maritime Electric Cayman Inc.	NR	0	0
54	Maritime Electric Company, Limited	12111 9879 RC0001	0	0
55	Mt. Hayes (GP) Ltd.	84888 3914 RC0001	0	0
56	Newfoundland Electric Company Limited	12748 1059 RC0001	0	0
57	Newfoundland Energy Cayman Inc.	NR	0	0
58	Newfoundland Industries Limited	87536 2774 RC0001	0	0
59	Newfoundland Power Inc.	10386 4831 RC0001	0	0
60	Terasen Gas Holdings Inc.	86602 7832 RC0001	0	0
61	Terasen International Inc.	13237 5346 RC0001	0	0
62	The Gananoque Water Power Company	10521 4068 RC0001	54,889	0
63	Waneta Expansion General Partner	84815 4001 RC0001	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
64	West Kootenay Power Ltd.	89427 8670 RC0001	0	0
		Total	450 232,244,791	550 109,268,621

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Canadian Niagara Power Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2004-01-01	1601365

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1130	Bertie Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Fort Erie	ON	CA	L2A 5Y2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [2] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 KING (Last name) **451** GLEN (First name)

454 _____ (Middle name(s))

460 [2] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 2 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name/Rural route/Lot and Concession number | **540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 1 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
HARRY CLUTTERBUCK	(905) 871-0330

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** _____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 6,575,204

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\% - \left[5\% \times \frac{\text{amount on line 300 } \textbf{minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 } \textbf{minus } \$\ 400{,}000}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	Niagara College	Electrical Engineering Technology Program
2.	Niagara College	Electrical Engineering Technology Program
3.		
4.		

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	Wendel Dickau	2011-05-02	2011-09-02
2.	Wendel Dickau	2011-09-05	2011-12-22
3.	Brent Sheppard	2011-05-02	2011-09-02
4.	Brent Sheppard	2011-09-05	2011-12-23

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	13,990	25.000 %		18
2.		10.000 %	11,658	25.000 %		15
3.		10.000 %	13,068	25.000 %		18
4.		10.000 %	11,617	25.000 %		16

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,498	3,000	3,000		3,000
2.	2,915	3,000	2,915		2,915
3.	3,267	3,000	3,000		3,000
4.	2,904	3,000	2,904		2,904

Ontario co-operative education tax credit (total of amounts in column K) **500** 11,819 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
HARRY CLUTTERBUCK	(905) 871-0330

Is the claim filed for an ATTC earned through a partnership? * . . . . . 150 1 Yes ☐ 2 No ☒

If **yes** to the question at line 150, what is the name of the partnership? . . . . . 160 _____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . 170 _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . 200 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . 210 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 6,575,204

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\% - \left[5\% \times \frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\% - \left[10\% \times \frac{\text{amount on line 300 } \textbf{minus } 400{,}000}{200{,}000} \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code **400**	B Apprenticeship program/ trade name **405**	C Name of apprentice **410**
1.	434a	Powerline Technician	Joshua Cook

	D Original contract or training agreement number **420**	E Original registration date of apprenticeship contract or training agreement (see note 1 below) **425**	F Start date of employment as an apprentice in the tax year (see note 2 below) **430**	G End date of employment as an apprentice in the tax year (see note 3 below) **435**
1.	971654	2010-05-17	2011-01-01	2011-04-16

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		106	106	2,904

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		22,494	22,494	7,873

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	2,904		2,904

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 2,904 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . Canadian Niagara Power Inc.

Taxation Year . . . . . 2011-01-01 to 2011-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . Y

Corporation is related . . . . . Y

Number of associated corporations . . . 64

Type of corporation . . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . . -40,570

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	867,866
Taxable income	867,866
Donations	
Calculation of income from an active business carried on in Canada	867,866
Dividends paid	
Dividends paid – Regular	
Dividends paid – Eligible	
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	
Balance of the general rate income pool at the end of the year	
Part I tax (base amount)	329,789

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	143,197	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	271,000
Investment tax credits		Other*		Surtax credit	
Abatement/Other*	186,592	Provincial or territorial tax	87,233	Other*	

Balance due/refund (–) -40,570

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Cumulative eligible capital	89,416
Financial statement reserve	1,855,324

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	867,866		
Taxable income	867,866		
% Allocation	100.00		
Attributed taxable income	867,866		
Surtax		N/A	N/A
Tax payable before deduction*	101,956		
Deductions and credits			
Net tax payable	101,956		
Attributed taxable capital			N/A
Capital tax payable**			N/A
Total tax payable***	101,956		
Instalments and refundable credits	14,723		
Balance due/Refund (-)	87,233		
Logging tax payable			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Canadian Niagara Power Inc.			37,329,867	37,329,867
0928418 BC Ltd				
1228158 Ontario Limited				
16006059 Ontario Inc.				
52905 Newfoundland and Labrador				
605555 BC LTD.				
630319 BC Ltd.				
Algoma Power Inc.	82,936,699		35,387,235	35,387,235
Atlantic Equipment & Power (Turks & Caicos)				
BC Gas (Argentina) S.A.				
BC Gas (Malaysia) SDN. BHD.				
BC Gas International (BVI) Inc.				
BC Gas International (BVI-II) Inc.				
BC Gas International (BVI-III) Inc.				
BC Gas International (Middle East)				
BC Gas International Projects Ltd.				
Belize Electric Company Limited				
Belize Electricity Limited				
Caribbean Utilities Company, Ltd.				
Cornwall Street Railway Light and Power Company Limited	34,457,844		18,162,225	18,162,225
ESI Power-Walden Corporation				
Fortis Alberta Holdings Inc.				
Fortis Belize Limited				
Fortis Cayman Inc.				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Fortis Energy (Bermuda) Ltd.				
Fortis Energy Cayman Inc.				
Fortis Energy Corporation				
Fortis Energy International (Belize)				
Fortis Generation East GP Inc				
Fortis Generation Inc				
Fortis Hydro Corporation				
Fortis Inc.				
Fortis Properties Corporation				
Fortis TCI Limited				
Fortis US Energy Corporation				
Fortis West Inc.				
FortisAlberta Inc.				
FortisBC Alternative Energy Services Inc.				
FortisBC Energy (Vancouver Island) Inc.				
FortisBC Energy (Whistler) Inc.				
FortisBC Energy Inc.				
FortisBC Holdings Inc.				
FortisBC Huntington Inc.				
FortisBC Inc.				
FortisBC Pacific Holdings Inc.				
FortisBC Storage Inc.				
FortisOntario District Heating Inc.			2,871	2,871
FortisOntario Inc.	52,176,798		166,306,824	166,306,824
FortisUS Holdings Nova Scotia Limited				
FortisUS Inc.				
Inland Energy Corp.				
Inland Pacific Energy Services				
Maritime Belize Limited				
Maritime Electric Cayman Inc.				
Maritime Electric Company, Limited				
Mt. Hayes (GP) Ltd.				
Newfoundland Electric Company Limited				
Newfoundland Energy Cayman Inc.				
Newfoundland Industries Limited				
Newfoundland Power Inc.				
Terasen Gas Holdings Inc.				
Terasen International Inc.				
The Gananoque Water Power Company	54,889		54,889	54,889
Waneta Expansion General Partner				
West Kootenay Power Ltd.				
Total	169,626,230		257,243,911	257,243,911

Québec

Corporate name	Paid-up capital used to calculate the deduction relating to income-averaging for forest producers (CO-726.30)	Paid-up capital used to calculate the exemption for small and medium-sized manufacturing businesses (CO-737.18.18)	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total					

Ontario

Corporate name	Taxable capital used to calculate the capital deduction – Ontario capital tax on financial institutions (Schedule 514)	Taxable capital used to calculate the capital deduction – Ontario capital tax on other than financial institutions (Schedule 515)	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total			

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)	Net paid up capital – BC capital tax on financial institutions (FIN 689)	BC paid up capital – BC capital tax on financial institutions (FIN 689)
Total				

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2011-12-31**	**2010-12-31**	**2009-12-31**	**2008-12-31**	**2007-12-31**
Net income	867,866	1,745,091	2,768,589		
Taxable income	867,866	1,745,091	859,190		
Active business income	867,866	1,745,091	2,768,589		
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations			27,100		
Balance due/refund (-)	-40,570	-455,450	-107,889		

Federal taxes

Part I before surtax	143,197	314,117	161,246		
Surtax					
Part I.3					
Part IV					
Part I & Surtax	143,197	314,117	161,246		
Part III.1					
Other*			627,433		

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit			2,000		
Abatement/other*	186,592	349,018	163,246		

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

ITC refund					
Dividend refund					
Instalments	271,000	1,056,000	1,210,000		
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2011-12-31	2010-12-31	2009-12-31	2008-12-31	2007-12-31
Net income	867,866	1,745,091	2,768,589		
Taxable income	867,866	1,745,091	859,190		
% Allocation	100.00	100.00	100.00		
Attributed taxable income	867,866	1,745,091	859,190		
Surtax					
Income tax payable before deduction	101,956	226,719	120,287		
Income tax deductions /credits			21,441		
Net income tax payable	101,956	226,719	98,846		
Taxable capital		95,514,739	99,498,319		
Capital tax payable		68,988	217,711		
Total tax payable*	101,956	295,707	316,557		
Instalments and refundable credits	14,723	9,274	3,125		
Balance due/refund**	87,233	286,433	313,432		

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Canada Revenue Agency / Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation			
Canadian Niagara Power Inc.			
Business Number	Tax year ▶	From Y M D	To Y M D
87249 8225 RC0002		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	867,866
Part I tax payable (line 700)	143,197
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	87,233
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, KING (Last name in block letters) GLEN (First name in block letters) Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2012-06-27 (Date (yyyy/mm/dd)) _____ (Signature of an authorized signing officer of the corporation) (905) 871-0330 (Telephone number)

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: FortisOntario Inc. Electronic filer number: I3522

Privacy Act, Personal Information Bank number CRA PPU 047

T183 CORP (11)

Canada

T2 BAR CODE RETURN

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002

Tax Year Start: 2011-01-01

Tax Year End: 2011-12-31

Financial Statements

Canadian Niagara Power Inc.

December 31, 2011

INDEPENDENT AUDITORS' REPORT

To the Shareholder of

Canadian Niagara Power Inc.

We have audited the accompanying financial statements of Canadian Niagara Power Inc., which comprise the balance sheet as at December 31, 2011 and 2010, and January 1, 2010, and the statements of income, retained earnings and cash flows for the years ended December 31, 2011 and 2010, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

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

Auditors' responsibility

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

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

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

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

Opinion

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

In our opinion, the financial statements present fairly, in all material respects, the financial position of Canadian Niagara Power Inc. as at December 31, 2011 and 2010, and January 1, 2010, and the results of its operations and its cash flows for the years ended December 31, 2011 and 2010 in accordance with Canadian accounting standards for private enterprises.

Toronto, Canada, Chartered Accountants
February 29, 2012. Licensed Public Accountants

1. FIRST-TIME ADOPTION OF ACCOUNTING STANDARDS FOR PRIVATE ENTERPRISES AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

Canadian Niagara Power Inc. [the "Corporation"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out in a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business

of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. FIRST-TIME ADOPTION OF ACCOUNTING STANDARDS FOR PRIVATE ENTERPRISES

These financial statements are the first financial statements which the Corporation has prepared in accordance with the new accounting standards for private enterprises ["ASPE"], as per Part II of the CICA Handbook - Accounting, which constitutes generally accepted accounting principles for non -publicly accountable enterprises in Canada. In preparing its opening balance sheet as at January 1, 2010 [the "Transition Date"], the Corporation has applied Section 1500, First-time adoption, retrospectively [other than the permitted exemptions noted below] using the following four principles such that it has:

" Recognized all assets and liabilities whose recognition is required by GAAP;
" Not recognized items as assets or liabilities if GAAP does not permit such recognition;
" Reclassified items recognized previously as one type of asset, liability or component of equity, but are now recognized as a different type of asset, liability or component of equity;
" Applied GAAP in measuring all recognized assets and liabilities.

The Corporation has consistently applied the same accounting policies in its opening ASPE balance sheet at January 1, 2010 and throughout all periods presented as if these policies had always been in effect. Upon adoption, there was no transitional financial impact on the financial statements of the Corporation.

Exemptions elected upon transition

Section 1500 provides a number of elective exemptions from the retrospective adoption of ASPE. The Corporation has elected to use the following transition exemption:

[i] Related party transactions - Section 3840, Related Party Transactions, specifies that certain related party transactions shall be measured at the carrying amount and some at the exchange amount. The Corporation has elected not to restate assets and liabilities related to transactions with related parties when the related party transaction occurred prior to the Transition Date.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

The transmission and distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of

return on rate-base, plus a recovery of all allowable distribution costs of CNPI.

The current rates of CNPI are based upon the 2009 Rate Orders issued by the OEB for new rates effective May 1, 2009, plus two Third-Generation Incentive Rate Mechanism ["IRM"] electricity distribution rate applications for 2010 and 2011, as described below. As part of the 2009 Rate Orders, the distribution rates of Fort Erie and Gananoque were harmonized.

In 2009, the Corporation filed IRM electricity distribution rate applications in Fort Erie, Gananoque and Port Colborne, for rates effective May 1, 2010. The OEB issued its Decisions and Orders related to these applications on April 16, 2010. The Decisions and Orders resulted in average increases of 1.4% in Fort Erie and 6.6% in Port Colborne and an average decrease of 5.6% in Gananoque. Core distribution rates were increased based on an inflation factor of 1.3% offset by a productivity factor of 0.72% and stretch factors ranging from 0.4% to 0.6%. Other factors influencing final rates were the discontinuance of certain rate riders from the 2009 applications, the disposition of December 31, 2008 regulatory deferral accounts, the final stage of transition to the 60/40 debt/equity structure and capital tax adjustments.

On November 8, 2010, the Corporation filed IRM electricity distribution rate applications for Fort Erie, Gananoque and Port Colborne for rates effective May 1, 2011. Core distribution rates were increased based on an inflation factor 1.3%, offset by the productivity factor of 0.72% and a stretch factor for Port Colborne of 0.6% and a stretch factor for Fort Erie and Gananoque of 0.4%. The 2011 price cap index was therefore -0.02% for Port Colborne and 0.18% for Fort Erie and Gananoque. The IRM maintained a return on equity of

8.01% with a 60/40 debt equity structure. The OEB issued its Decision and Order for Port Colborne on March 28, 2011 which resulted in an average decrease of 4.0% for the average residential customer. The decrease was primarily the result of reductions in deferral account rate riders. The OEB issued its final Decision and Order for Fort Erie and Gananoque on April 14, 2011 which resulted in an average increase of 3.8% for the average residential customer in Gananoque; this increase was primarily the result of increases in deferral account rate riders and an increase to the smart meter funding adder. The Decision and Order resulted in an average increase of 1.7% for the average residential customer in Fort Erie; this increase was primarily the result of increases to the smart meter funding adder.

The Corporation filed two IRM electricity distribution rate applications on November 10, 2011 for Fort Erie, Gananoque and Port Colborne. A harmonized IRM application was filed for Fort Erie and Gananoque. The OEB has yet to publish the applicable inflation factor and productivity and stretch factors for 2012. It is anticipated that the numbers will be available in the first quarter of 2012. The third generation IRM maintains a return on equity of 8.01% with a 60/40 debt equity structure. As at December 31, 2011, no Decisions and Orders on these applications have been issued by the OEB.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2011 were $80 [2010 - $105].

Utility capital assets

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 3.3% [2010 - 3.4%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

General expenses capitalized ["GEC"] are capitalized overhead costs which are not directly attributable to specific utility capital assets but relate to the

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Corporation's overall capital program. GEC is permitted by the OEB's Distribution Rate Handbook and Accounting Procedures Handbook. In the absence of rate regulation, utility overhead costs which are not directly attributable to construction activity would not be capitalized. GEC is allocated over the constructed utility capital assets and amortized based on the rate applicable to these assets.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long-lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of ASPE.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of

the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as of January 1, 2004] over the assigned value of identifiable net assets acquired.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Operating lease

The Corporation has entered into an operating lease, which expires in 2012, with the City of Port Colborne, whereby the Corporation operates and maintains the City of Port Colborne's electricity distribution assets and provides service to the residents of Port Colborne. The Corporation recognizes all revenue relating to this agreement in operating revenue and records the cost of the lease as operating lease expense. At the end of the lease term, the Corporation has the option to purchase the assets at a pre-determined amount.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to

customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2011 is $4,432 [2010 - $4,642].

Translation of foreign currencies

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans and change in measurement date accounting policy

The Corporation accrues its obligations under employee benefit plans. The cost of pension benefits and other retirement benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of discount rates, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are valued at fair value. The excess of any cumulative net actuarial gain (loss) over 10% of the greater of the benefit obligation and the fair value of plan assets is amortized over the average remaining service period of active employees.

Name: Canadian Niagara Power Inc.

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Prior to 2011, the Corporation measured the plan assets and accrued benefit obligations for both its pension benefit plans and other retirement plans as of September 30th of each year. In 2011, the Corporation changed the measurement date to December 31st in order to align with the reporting date of its parent company, Fortis Ontario Inc. This change had no significant impact on the plan assets and pension obligations.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. Effective January 1, 2009, the Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE 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 revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as

adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

	2011		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,616	11,210	11,406
Distribution	90,825	29,342	61,483
Other	13,167	7,671	5,496
	126,608	48,223	78,385

	2010		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,556	10,606	11,950
Distribution	86,356	26,754	59,602
Other	12,167	6,872	5,295
	121,079	44,232	76,847

Name: Canadian Niagara Power Inc.

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	January 1, 2010		
	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	22,356	10,005	12,351
Distribution	81,675	24,207	57,468
Other	11,438	6,097	5,341
	115,469	40,309	75,160

The amounts above include assets under construction, which are not subject to amortization, of $3,131 [2010 - $2,906; January 1, 2010 - $3,866].

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2011		
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	7,912	4,787	3,125
Land and transmission rights	6,827	2,249	4,578
Other	255	58	197
	14,994	7,094	7,900

	2010		
		Accumulated	Net book

	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	7,162	4,265	2,897
Land and transmission rights	6,779	2,080	4,699
Other	255	52	203
	14,196	6,397	7,799

January 1, 2010			
	Cost	Accumulated amortization	Net book value
	$	$	$
Software costs	5,730	3,891	1,839
Land and transmission rights	6,730	1,913	4,817
Other	255	45	210
	12,715	5,849	6,866

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

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BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan			Other retirement plan		
	2011	2010	January 1, 2010	2011	2010	January 1, 2010
	$	$	$	$	$	$
Accrued benefit obligation						
Balance, beginning of year	12,999	12,022	11,970	5,024	4,042	4,160
Current service cost	322	282	263	93	65	78
Interest cost	669	757	764	275	269	279
Benefits paid	(1,103)	(897)	(913)	(310)	(159)	(293)
Actuarial losses (gains)	413	835	(62)	340	807	(182)
Balance, end of year	13,300	12,999	12,022	5,422	5,024	4,042
Plan assets						
Fair value, beginning of year	11,871	11,737	11,357	--	--	--
Actual return on plan assets	1,372	166	746	--	--	--
Contributions	962	985	631	--	--	--
Benefits paid	(1,103)	(897)	(914)	--	--	--
Plan expenses	(112)	(120)	(83)	--	--	--
Fair value, end of year	12,990	11,871	11,737	--	--	--
Funded status - deficit	(310)	(1,128)	(285)	(5,422)	(5,024)	(4,042)

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
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Unamortized amounts

Actuarial losses 2,477 2,900 1,567 1,140 767 4

Prior service costs 29 33 38 44 87 137

Transitional obligation 187 206 224 ? -- --

Accrued benefit asset (liability) 2,383 2,011 1,544 (4,238)

(4,170) (3,901)

As per note 1, the measurement date for the plan assets and the accrued benefit obligation is December 31, 2011. The effective date of the most recent actuarial valuation was as of December 31, 2009 and the next required valuation for funding purposes is as of December 31, 2012.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

%

Canadian equity funds 14

U.S. equity funds 13

EAFE equity funds 12

Canadian fixed income funds 59

Cash and short-term investments 2

Pension benefit plan Other retirement plan

2011 2010 2011 2010

$ $ $ $

Significant assumptions used

Discount rate	5.10%	5.20%	5.25%	5.40%
Expected long-term rate of return on plan assets	6.25%	6.25%	-	-
Rate of compensation increase	4.00%	4.00%	-	-
Assumed health care trend rate	-	-	4.50%	4.50%
Average remaining service period of active employees [years]	8	9	17	17

Net benefit expense for the year				
Current service cost	420	385	93	65
Interest cost	669	757	275	269
Expected return on plan assets	(724)	(711)	-	-
Actuarial losses	203	64	15	-
Amortization of transitional obligation and past service costs	23	23	44	44
Net benefit expense	591	518	427	378

The total expense for the Corporation's defined contribution pension plan for the year amounted to $212 [2010 - $200]. The pension cost associated with the OMERS plan was $108 [2010 - $72].

5. INCOME TAXES

The provision for income taxes (recovery) consists of the following:

2011	2010
$	$

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
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Current income taxes 189 574
Future income taxes
Future income taxes transferred to regulatory assets 424
(424) 376
(376)
189 574

As per note 1, during the year, the Corporation recorded $424 in regulatory assets and a corresponding offset to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

	2011	2010	January 1, 2010
	$	$	$
Future tax liabilities (assets)			
Utility capital assets	4,013	3,641	3,286
Employee future benefits	(464)	(539)	(589)
Other assets	60	83	112
Net future tax liabilities	3,609	3,185	2,809

6. RELATED PARTY TRANSACTIONS

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

During the year, the Corporation entered into the following transactions with related parties:

	2011	2010
	$	$
Receipts		
Administrative services to		
FortisOntario Inc.	111	147
Cornwall Street Railway, Light and Power Company Limited	1,532	1,483
Algoma Power Inc.	881	-
Reimbursement of expenses paid on behalf of and services provided to		
FortisOntario Inc.	287	292
Fortis Properties Corporation	227	242
Algoma Power Inc.	1,014	1,452
Westario Power Holdings Inc.		
Grimsby Power Inc.		
Cornwall Street Railway, Light and Power Company Limited	273	
151		
431	228	
85		
94		
Payments		
Purchased power from Fortis Properties Corporation	1,370	848
Management fees paid to FortisOntario Inc.	725	831
Rent paid to FortisOntario Inc.	485	485

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Interest expense paid to (received from)
Cornwall Street Railway, Light and Power Company Limited (2) (7)
FortisOntario Inc.
Algoma Power Inc. 1,352
13 1,329
-
Reimbursement for expenses paid on behalf of and services
provided from
FortisOntario Inc. 3,778 3,769
Newfoundland Power Inc. 5 -

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

At December 31, the amounts due to (from) related parties are as follows:

2011 2010 January 1, 2010
$ $ $

Due to (from) FortisOntario Inc. 3,073 4,047 (16)
Due to Fortis Inc. ? ? 23
Due to Fortis Properties Corporation 156 260 93
Due to Cornwall Street Railway, Light and Power Company Limited
?
?
671

Due from Westario Power Holdings Inc.

Due from Grimsby Power Inc.

Due from Algoma Power Inc. (18)

(63)

(355) (65)

(37)

(169) (23)

-

(131)

2,793 4,036 617

Promissory notes due to parent 20,000 20,000 20,000

A promissory note of $15,000 due to the parent company bears interest at a rate of 6.13% and is payable on demand. A promissory note of $5,000 due to the parent company bears interest at a rate of 7.62% and is payable on demand. There are no specific terms of repayment for these notes.

7. LONG-TERM DEBT

Long-term debt consists of the following:

2011 2010 January 1, 2010

$ $ $

7.092% senior unsecured notes due August 14, 2018 30,000 30,000

30,000

Unamortized debt issue costs (211) (243) (275)

29,789 29,757 29,725

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,128 [2010 - $2,128].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2011, the accumulated amortization was $269 [2010 - $237; January 1, 2010 - $205].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2011	2010
	$	$
Amortization of utility capital assets	4,068	3,997
Amortization of contributions in aid of construction	(310)	(283)
Amortization of intangible assets and other	695	548
	4,453	4,262

10. STATEMENTS OF CASH FLOWS

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

The net change in non-cash working capital balances related to operations consists of the following:

	2011	2010
	$	$
Accounts receivable	1,525	805
Due to related parties	(1,243)	3,419
Materials and supplies	(53)	(1)
Prepaid expenses	45	(260)
Accounts payable and accrued liabilities	(100)	21
Regulatory assets/liabilities	94	(915)
Income taxes payable/receivable	219	232
	487	3,301

Supplemental cash flow information:

	2011	2010
	$	$
Interest paid	3,742	3,375
Income taxes paid	271	940

11. COMMITMENTS AND CONTINGENCIES

The Corporation has a commitment under an operating lease agreement for the lease of the electricity distribution assets of Port Colborne Hydro Inc.

["PCHI"]. Future minimum lease payments under the agreement, which runs until April 2012, total $489.

In April 2011, the Corporation provided The Corporation of the City of Port Colborne and PCHI an irrevocable written notice of its election to exercise the purchase option under the current operating lease agreement, at the purchase option price of $6,900 on April 15, 2012. The purchase constitutes the sale of the remaining assets of PCHI to the Corporation. This purchase will be subject to OEB approval under Section 86 of the Ontario Energy Board Act.

12. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk: Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk: Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk: Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance

sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	As at December 31, 2011 $
Not past due	8,588
Past due 0-30 days	348
Past due 31-60 days	71
Past due 61 days and over	139
	9,146
Less allowance for doubtful accounts	145
	9,001

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds.

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These funds are a result of allowable rate-regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation is a subsidiary of Fortis Inc., a large investor-owned utility, which has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. The recent volatility in the global markets may increase the cost of and timing of issuance of long-term capital by Fortis Inc. and its subsidiaries.

To mitigate any liquidity risk, the Corporation has committed revolving credit facilities and letters of credit facilities totalling $8,000, of which approximately $3,700 is unused. The revolving credit facilities and letters of credit facilities are renewed on an annual basis. The following summary outlines the credit facilities of the Corporation:
?

	2011	2010
	$	$
Total credit facilities	8,000	8,000
Letters of credit outstanding	(4,282)	(4,282)
Credit facilities available	3,718	3,718

The facilities are collateralized by a general security agreement covering all assets of the Corporation and are guaranteed by the Corporation and its parent

company. The credit facilities bear interest at the bankers' acceptance rate plus 2.0% in the case of bankers' acceptances, and the bank's prime lending rate plus 1.0% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2011:

	< 1 year	1-3 years	4-5 years	> 5 years	Total
	$	$	$	$	$
Accounts payable and accrued liabilities	6,789	?	?	?	6,789
Government remittances payable	253	?	?	?	253
Customer deposits	338	215	128	?	681
Promissory notes due to parent	?	?	?	20,000	20,000
Long-term debt	?	?	?	30,000	30,000
	7,380	215	128	50,000	57,723

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2011 and 2010 are nil.

13. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital

structure reflected in the utility's customer rates. Effective May 1, 2010, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2011 Actual		2010 Actual		As at January 1, 2010	
	$	%	$	%	$	%
Debt	50,000	57	50,000	57	50,000	57
Equity	37,330	43	37,324	43	37,202	43
	87,330	100	87,324	100	87,202	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 65% to 70% of their respective capital structures as defined in the agreements. As at December 31, 2011, the Corporation was in compliance with its debt covenants.

14. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power

itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet dates. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period they are incurred.

In 2006, the Government of Ontario committed to install a smart electricity meter in all Ontario homes and small businesses by the end of 2010. The Corporation will be eligible to recover all prudent and reasonable costs that arise from this smart metering initiative. These costs represent incremental operating, administrative and capital costs directly related to smart meters.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition which may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates, as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as

permitted by the regulators.

	2011	2010	January 1, 2010	Remaining rebate
	$	$	$	period
Current regulatory assets				
Amounts approved in current rates	570	664	67	1 year
Long-term regulatory assets				
Retail settlement and other variance accounts	3,634	3,984	5,675	1.5+ years
Smart meter variance account	4,001	3,711	2,076	2+ years
Future taxes to be recovered from customers	3,609	3,185	2,809	life of assets
Other	50	117	343	
	11,294	10,997	10,903	
Current regulatory liabilities				
Amounts approved in current rates	?	?	318	
Long-term regulatory liabilities				
Retail settlement and other variance accounts	2,552	3,040	1,921	2+ years
Other	498	54	171	2+ years
	3,050	3,094	2,092	

15. SEGMENTED INFORMATION

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

[a] Earnings

2011

Fort Erie & Eastern Ontario Power

Port Colborne

Fort Erie

	Distribution	Distribution	Transmission	Total
	$	$	$	$
Operating revenue	43,258	23,483	4,769	71,510
Purchased power	30,894	18,015	-	48,909
Operating expenses	4,955	3,041	1,712	9,708
Operating lease	-	1,523	-	1,523
Amortization	3,212	475	766	4,453
Operating earnings	4,197	429	2,291	6,917
Interest expense	(2,426)	(661)	(635)	(3,722)
Income taxes	(105)	16	(100)	(189)
Net earnings	1,666	(216)	1,556	3,006

2010

	Fort Erie & Eastern Ontario Power	Port Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

Operating revenue	41,405	21,789	4,770	67,964
Purchased power	29,381	16,240	-	45,621
Operating expenses	5,036	2,859	1,577	9,472
Operating lease	-	1,523	-	1,523
Amortization	3,048	452	762	4,262
Operating earnings	3,940	715	2,431	7,086
Interest expense	(2,196)	(542)	(652)	(3,390)
Income taxes	(272)	(27)	(275)	(574)
Net earnings	1,472	146	1,504	3,122

[b] Utility capital assets

2011			
Fort Erie & Eastern Ontario Power Distribution	Port Colborne Distribution	Fort Erie Transmission	Total
$	$	$	$
Cost	87,138	16,854	22,616	126,608
Accumulated amortization	34,414	2,599	11,210	48,223
	52,724	14,255	11,406	78,385

2010		
Fort Erie & Eastern Ontario	Port	

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2011-01-01
Tax Year End: 2011-12-31

	Power Distribution	Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$
Cost	82,812	15,711	22,556	121,079
Accumulated amortization	31,527	2,099	10,606	44,232
	51,285	13,612	11,950	76,847

	January 1, 2010 Fort Erie & Eastern Ontario Power Distribution	Colborne Distribution	Fort Erie Transmission	Total
	$	$	$	$
Cost	78,902	14,211	22,356	115,469
Accumulated amortization	28,684	1,620	10,005	40,309
	50,218	12,591	12,351	75,160

16. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2011 financial statements.

(EP)

4. Operating Costs

4.6 Is the proposed CNPI – Fort Erie/Gananoque forecast for Income Taxes for the test year appropriate?

66. Ref: Exhibit 4, Tab 8, Schedule 2

a) Please show the Ontario Apprentice and co-op tax credits available to CNPI in 2011 split between transmission and distribution.

b) Please provide the forecast of the Ontario apprentice and co-op tax credits available in 2013. Please show the calculation, including the number of eligible positions and the credit per position. Please show the allocation between transmission and distribution and how this allocation has been calculated.

c) Is CNPI eligible for any federal job creation or other tax credits?

d) Please show how the calculation of the reduction in PILS related to the Ontario Small Business Deduction has been incorporated into the PILS forecast. Please confirm that the small business rate of 4.5% is applicable to first $500,000 of taxable income, with no clawback.

RESPONSE:

a) The Ontario Apprentice and co-op tax credits for 2011, 2012 and 2013 were estimated at $4,000 based on 2009 actual. The split between transmission and distribution is based on the FTEs per the BDR report. The FTEs for transmission is 10.18 (13.1%) and for distribution 67.4 (86.9%). Therefore the transmission credit is $525 and the distribution credit is $3,475.

The 2011 actual Ontario Apprentice and co-op tax credits were $14,723. The split would be for transmission $1,929 and distribution $12,794.

b) Please see response to a) above.

c) CNPI is not aware of any federal job creation or other tax credits available to it.

d) CNPI is a wholly-owned subsidiary of FortisOntario Inc. who is a wholly-owned subsidiary of Fortis Inc. Fortis Inc.'s shares are listed on the Toronto Stock Exchange and thus, Fortis Inc. is considered a public corporation under the Income Tax Act. CNPI is considered a corporation controlled by a public corporation under the Income Tax Act. CNPI is not considered a Canadian-controlled private corporation (CCPC) because it is owned indirectly by a public corporation. To be eligible for the Ontario Small Business Deduction (OSBD) a corporation must be a CCPC. CNPI does not qualify for the OSBD.

4. Operating Costs

4.7
Is the proposed CNPI – Port Colborne forecast for Income Taxes for the test year appropriate?

(OEB)

Operating Costs

Issue 4.7
Is the Proposed CNPI – Port Colborne forecast for Income Taxes for the test year appropriate?

44. Ref: E4/T8/S2/p.2

Please provide a live excel model of CNPI's tax calculation for PC.

RESPONSE:

Please refer to live excel spreadsheet - BoardStaff_IR_44_A_20120718 attached.

TAX CALCULATIONS - Port Colborne

Description	TOTAL CNPI 2009 Actual	TRANSMISSION 2009 Actual	DISTRIBUTION 2009 Actual	TOTAL CNPI 2010 Actual	TRANSMISSION 2010 Actual	DISTRIBUTION 2010 Actual	TOTAL CNPI 2011 Forecast	TRANSMISSION 2011 Forecast	DISTRIBUTION 2011 Forecast	TOTAL CNPI 2012 Regulatory	TRANSMISSION 2012 Forecast	DISTRIBUTION 2012 Regulatory	TOTAL CNPI 2013 Regulatory	TRANSMISSION 2013 Forecast	DISTRIBUTION 2013 Regulatory
Net income(loss) per financial statements	3,024,635	1,323,074	1,701,561	3,121,711	1,504,497	1,617,214	3,005,857	1,555,846	1,450,011	-	-	-	-	-	-
Utility income before taxes	-	-	-	-	-	-	-	-	-	3,450,067	1,236,000	2,214,067	3,893,068	1,215,000	2,678,068
Add:															
Provision for income taxes - current	878,461	395,534	482,927	573,810	275,206	298,604	188,737	100,033	88,704	-	-	-	-	-	-
Provision for income taxes - deferred	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest and penalities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of assets	4,075,289	756,056	3,319,233	4,262,383	762,455	3,499,928	4,452,997	765,727	3,687,270	5,363,652	884,000	4,479,652	6,069,339	901,000	5,168,339
Loss on disposal of assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SHRED	64,716	-	64,716	-	-	-	-	-	-	-	-	-	-	-	-
Donations	27,100	2,389	24,711	-	-	-	-	-	-	-	-	-	-	-	-
Non-deductible meals and entertainment	17,858	1,574	16,284	19,228	2,523	16,705	19,000	2,493	16,507	19,000	2,493	16,507	19,000	2,493	16,507
Reserves from financial statements - EOY	2,357,583	207,811	2,149,772	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918	1,676,000	219,924	1,456,076
Amortization of deferred financing	32,028	12,798	19,230	32,028	10,776	21,252	32,028	7,393	24,635	32,028	7,299	24,729	32,028	7,212	24,816
Amortization of deferred lease costs	58,140	-	58,140	58,140	-	58,140	58,140	-	58,140	19,380	-	19,380	-	-	-
Ontario apprentice and co-op tax credits	4,333	382	3,951	11,274	1,479	9,795	4,000	525	3,475	4,000	525	3,475	4,000	525	3,475
Total Additions	7,515,508	1,376,544	6,138,964	7,115,278	1,335,665	5,779,613	6,609,902	1,119,583	5,490,319	7,260,060	1,133,399	6,126,661	7,800,367	1,131,153	6,669,213
Deduct:															
Gain on disposal of assets per financial statements	51,467	-	51,467	37,802	-	37,802	25,266	-	25,266	-	-	-	-	-	-
Capital cost allowance	4,178,748	554,313	3,624,435	5,102,785	538,668	4,564,117	5,592,886	524,476	5,068,410	5,672,863	680,078	4,992,785	5,960,047	861,745	5,098,302
Cumulative eligible capital deduction	7,781	(0)	7,781	7,237	-	7,237	6,730	-	6,730	6,259	-	6,259	6,259	-	6,259
Reserves from financial statements - BOY	2,386,859	210,392	2,176,467	2,357,583	309,361	2,048,222	2,158,415	283,226	1,875,189	1,855,000	243,412	1,611,588	1,822,000	239,082	1,582,918
Allowance for funds used during construction	116,308	116,308	-	16,338	16,338	-	-	-	-	-	-	-	-	-	-
Capitalized general expense	1,015,195	-	1,015,195	970,154	-	970,154	980,256	-	980,256	1,069,910	-	1,069,910	1,112,726	-	1,112,726
Capital amount expensed for tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Disallowed Ontario apprentice credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Deferred financing costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Deductions	7,756,358	881,013	6,875,345	8,491,899	864,366	7,627,532	8,763,553	807,702	7,955,851	8,604,032	923,489	7,680,542	8,901,032	1,100,827	7,800,205
Taxable Income	2,783,785	1,818,605	965,180	1,745,090	1,975,796	(230,706)	852,206	1,867,727	(1,015,521)	2,106,095	1,445,909	660,186	2,792,403	1,245,327	1,547,076
Corporate tax rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	739,987	330,012	409,975
Grossed Up Taxes															557,789
Calculation of total taxes															
Income Tax	918,649	600,140	318,509	540,978	612,497	(71,519)	240,748	527,633	(286,885)	558,115	383,166	174,949	887,801	330,012	557,789
Ontario apprentice and co-op tax credits	-	-	-	(9,416)	(1,236)	(8,180)	-	-	-	-	-	-	-	-	-
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777	-	-	-	-	-	-	-	-	-
Total taxes	**1,136,360**	**687,131**	**449,229**	**600,550**	**634,472**	**(33,922)**	**240,748**	**527,633**	**(286,885)**	**558,115**	**383,166**	**174,949**	**887,801**	**330,012**	**557,789**
Tax Rates															
Federal Tax	19.00%	19.00%	19.00%	18.00%	18.00%	18.00%	16.50%	16.50%	16.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Provincial Tax	14.00%	14.00%	14.00%	13.00%	13.00%	13.00%	11.75%	11.75%	11.75%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Total Tax Rate	33.00%	33.00%	33.00%	31.00%	31.00%	31.00%	28.25%	28.25%	28.25%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Calculation of Ontario Capital Tax															
Net Paid Up Capital 2006&2007/Total Rate Base 2008&2009	99,498,319	39,756,937	59,741,382	95,514,739	32,135,669	63,379,070									
Less Exemption	2,738,073	1,094,063	1,644,010	2,768,091	931,317	1,836,774									
Taxable Capital/Deemed Taxable Capital	96,760,246	38,662,874	58,097,372	92,746,648	31,204,352	61,542,296									
OCT Rate	0.225%	0.225%	0.225%	0.074%	0.074%	0.074%									
Ontario Capital Tax	217,711	86,991	130,719	68,988	23,211	45,777									
PORT COLBORNE RATE BASE			14,140,589			15,731,210			16,413,517			18,609,841			20,731,676
% OF TOTAL RATE BASE			24%			25%			25%			27%			28%
TOTAL TAXES			**106,331**			**(8,420)**			**(72,500)**			**47,115**			**157,521**

4. Operating Costs

4.8
Are the 2013 compensation costs and employee levels appropriate?

(OEB)

Operating Costs

Issue 4.8
Are the 2013 compensation costs and employee levels appropriate?

45. Ref: E4/T4/S1, Appendix 2-K and E4/T4/S1, Appendix B

On page 1 of Appendix B CNPI stated that the total complement of CNPI's FTEs carries out work for three business units: CNPI FE/EOP, CNPI PC and CNPI Transmission. CNPI further noted that it has reported the total CNPI payroll and headcount for 2012 Bridge and 2012 Test Year on an aggregate basis. Please file Appendix 2-K on an allocated basis for the FE/EOP and PC service territories.

RESPONSE:

Please refer to page 2. CNPI's filing for Appendix 2-K on allocated basis are attached (CNPI – FE/EOP and PC; CNPI – FE & EOP; CNPI – PC).

BDR 2012 ALLOCATED VERSION

APPENDIX 2-K
Compensation Analysis - CNPI - FE/EOP and PC

Number of Employees (FTE's including PT): *2012 BDR Report

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 BDR	2013 BDR
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	13.99	13.99	12.66	12.66	11.73	11.73
Non-Union	5.31	5.31	6.79	6.79	6.22	6.22
Union	41.80	41.80	45.74	45.74	49.45	50.15
TOTAL	61.10	61.10	65.18	65.18	67.40	68.10

1. The BDR Report methology was used in 2009 Board Approved. In 2009 FTE's exclude PTE's as per filing requirements. 2010-2013 FTE's include PTE's. In 2009 Actual there was no change in actual allocations. The API BDR Report was used for 2010 and 2011.
The BDR Report in Exhibit 4, Tab 5, Schedule 2, Appendix E was used for 2012 and 2013.
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. 2012 Total CNPI Dx on 2012 BDR Report is 67.40 - Breakdown to Mgmt, Non-Union and Union accordingly
4. While there is 1 new actual FTE being added to 2013 Test Year by CNPI, on an allocated basis using BDR Report approximately 0.7 FTE is being allocated to the CNPI distribution business units for the purpose of this Application.

Number of Part Time Employees (PTE's):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	4.9	5	5	5	5	5
TOTAL	**4.9**	**5**	**5**	**5**	**5**	**5**

1. PTE's based on actual number of part-time employees.

Total Salary and Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 1,718,406	$ 1,589,955	$ 1,461,479	$ 1,520,367	$ 1,456,215	$ 1,494,352
Non-Union	$ 388,873	$ 393,050	$ 499,666	$ 505,563	$ 475,108	$ 490,012
Union	$ 3,236,403	$ 2,756,473	$ 3,062,018	$ 3,238,417	$ 3,613,753	$ 3,741,898
TOTAL	**$ 5,343,682**	**$ 4,739,479**	**$ 5,023,163**	**$ 5,264,346**	**$ 5,545,076**	**$ 5,726,261**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on average salary, average OT and average incentive pay multiplied by the total of FTE's.

Current Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 249,945	$ 218,341	$ 342,492	$ 356,387	$ 389,696	$ 403,511
Non-Union	$ 54,544	$ 50,023	$ 80,180	$ 108,867	$ 108,732	$ 131,971
Union	$ 551,854	$ 502,275	$ 569,385	$ 595,206	$ 619,411	$ 646,055
TOTAL	**$ 856,343**	**$ 770,639**	**$ 992,058**	**$ 1,060,460**	**$ 1,117,839**	**$ 1,181,537**

1. Includes premuim cost of health, dental and LTD benefits, taxable benefits and pension contributions on behalf of employee made by the Company.
2. 2009 Actual - 20011 Actual based on actual costs. 2012 Bridge - 2013 Test Year based on quoted increases from CNPI benefits consultant of 5% increase for health, dental and LTD premiums.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
4. Calculated based on average Current Benefits multiplied by the total of FTE's.

Accrued Pension and Post-Retirement Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 147,200	$ 161,195	$ 144,860	$ 160,587	$ 145,229	$ 136,146
Non-Union	$ 41,749	$ 61,183	$ 77,659	$ 86,091	$ 70,559	$ 66,885
Union	$ 603,211	$ 481,627	$ 523,468	$ 580,299	$ 612,240	$ 569,885
TOTAL	**$ 792,160**	**$ 704,005**	**$ 745,987**	**$ 826,977**	**$ 828,028**	**$ 772,916**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. These amounts are determined by CNPI's pension consultant.
3. Calculated based on average Accrued and Post Retirement Benefits multiplied by the total of FTE's.

Total Benefits (Current & Accrued) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 397,145	$ 379,536	$ 347,986	$ 367,780	$ 356,856	$ 352,768
Non-Union	$ 96,294	$ 111,206	$ 137,906	$ 152,399	$ 122,851	$ 127,243
Union	$ 1,155,065	$ 983,902	$ 1,067,009	$ 1,156,304	$ 1,267,404	$ 1,248,434
TOTAL	**$ 1,648,504**	**$ 1,474,645**	**$ 1,552,902**	**$ 1,676,482**	**$ 1,747,110**	**$ 1,728,445**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits were not included in 2009 Board Approved.
3. Calculated based on Average Yearly Benefits multiplied by the total of FTE's.

Total Compensation (Salary, Wages & Benefits) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 2,115,551	$ 1,969,492	$ 1,809,466	$ 1,888,146	$ 1,813,070	$ 1,847,120
Non-Union	$ 485,166	$ 504,256	$ 637,572	$ 657,961	$ 597,960	$ 617,254
Union	$ 4,391,468	$ 3,740,375	$ 4,129,027	$ 4,394,721	$ 4,881,157	$ 4,990,332
TOTAL	**$ 6,992,185**	**$ 6,214,124**	**$ 6,576,064**	**$ 6,940,829**	**$ 7,292,187**	**$ 7,454,706**

1. Calculated as Total Salary and Wages plus Total Benefits
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. Accrued pension and benefits included in this Total Compensation.

Compensation - Average Yearly Base Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 107,470	$ 96,555	$ 96,811	$ 100,591	$ 104,046	$ 106,931
Non-Union	$ 67,857	$ 66,302	$ 66,920	$ 68,559	$ 70,544	$ 72,511
Union	$ 63,582	$ 62,639	$ 64,229	$ 66,798	$ 68,904	$ 70,314

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on total actual salary and wages divided by the actual number of FTE's

Compensation - Average Yearly Overtime ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	$ 5,720	$ 3,305	$ 2,722	$ 4,010	$ 4,175	$ 4,300

1. 2009 Actual based on actual overtime paid. 2012 Bridge- 2013 Test based on 3% forecasted annual increases over 2011 total actual (see E4,T4,S1,App A) and averaged over actual number of union employees.
2. Executive, Management and Non-union are not paid overtime compensation.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.

Compensation - Average Yearly Incentive Pay($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 15,361	$ 17,095	$ 18,662	$ 19,535	$ 20,098	$ 20,464
Non-Union	$ 5,377	$ 7,719	$ 6,722	$ 5,952	$ 5,840	$ 6,269
Union	N/A	N/A	N/A	N/A	N/A	N/A

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Union is not paid incentive pay.

Compensation - Average Yearly Benefits ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 17,866	$ 27,129	$ 27,495	$ 29,059	$ 30,422	$ 30,074
Non-Union	$ 10,272	$ 20,943	$ 20,325	$ 22,461	$ 19,751	$ 20,457
Union	$ 11,817	$ 23,538	$ 23,330	$ 25,282	$ 25,630	$ 24,894

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits not were not included in 2009 Board Approved.

Compensation - Charged OM&A/Capitalized ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Total Compensation	$ 6,200,275	$ 6,214,124	$ 6,576,064	$ 6,940,829	$ 7,292,187	$ 7,454,706
Total Compensation Charged to OM&A	$ 4,650,206	$ 4,660,593	$ 4,932,048	$ 5,205,621	$ 5,469,140	$ 5,591,029
Total Compensation Capitalized	$ 1,550,069	$ 1,553,531	$ 1,644,016	$ 1,735,207	$ 1,823,047	$ 1,863,676

1. Accrued Pension and Post Retirement was not included in 2009 Board Approved, which is not comparable to other years.
2. CNPI capitalizes approximately 25% of total labour through direct charges to capital projects.
3. Total Compensation Capitalized was not reported on 2009 Compensation Table.

BDR 2012 ALLOCATED VERSION - FE & EOP

APPENDIX 2-K
Compensation Analysis - CNPI - FE & EOP

Number of Employees (FTE's including PT): *2012 BDR Report

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 BDR	2013 BDR
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	9.79	9.79	8.86	8.86	8.21	8.21
Non-Union	3.72	3.72	4.75	4.75	4.35	4.35
Union	29.26	29.26	32.01	32.01	34.62	35.11
TOTAL	42.77	42.77	45.62	45.62	47.18	47.67

1. The BDR Report methology was used in 2009 Board Approved. In 2009 FTE's exclude PTE's as per filing requirements. 2010-2013 FTE's include PTE's. In 2009 Actual there was no change in actual allocations. The API BDR Report was used for 2010 and 2011.
The BDR Report in Exhibit 4, Tab 5, Schedule 2, Appendix E was used for 2012 and 2013.
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. 2012 Total CNPI Dx on 2012 BDR Report is 67.40 - Breakdown to Mgmt, Non-Union and Union accordingly
4. While there is 1 new actual FTE being added to 2013 Test Year by CNPI, on an allocated basis using BDR Report approximately 0.7 FTE is being allocated to the CNPI distribution business units for the purpose of this Application.

Number of Part Time Employees (PTE's):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	3.43	3.5	3.5	3.5	3.5	3.5
TOTAL	**3.43**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**

1. PTE's based on actual number of part-time employees.

Total Salary and Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 1,202,884	$ 1,112,969	$ 1,023,035	$ 1,064,256	$ 1,019,350	$ 1,046,046
Non-Union	$ 272,211	$ 275,135	$ 349,766	$ 353,894	$ 332,576	$ 343,008
Union	$ 2,265,482	$ 1,929,531	$ 2,143,412	$ 2,266,892	$ 2,529,627	$ 2,619,328
TOTAL	**$ 3,740,577**	**$ 3,317,635**	**$ 3,516,214**	**$ 3,685,042**	**$ 3,881,553**	**$ 4,008,383**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on average salary, average OT and average incentive pay multiplied by the total of FTE's.

Current Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 174,962	$ 152,839	$ 239,745	$ 249,471	$ 272,787	$ 282,458
Non-Union	$ 38,181	$ 35,016	$ 56,126	$ 76,207	$ 76,112	$ 92,380
Union	$ 386,298	$ 351,592	$ 398,570	$ 416,644	$ 433,588	$ 452,239
TOTAL	**$ 599,440**	**$ 539,447**	**$ 694,440**	**$ 742,322**	**$ 782,488**	**$ 827,076**

1. Includes premuim cost of health, dental and LTD benefits, taxable benefits and pension contributions on behalf of employee made by the Company.
2. 2009 Actual - 20011 Actual based on actual costs. 2012 Bridge - 2013 Test Year based on quoted increases from CNPI benefits consultant of 5% increase for health, dental and LTD premiums.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
4. Calculated based on average Current Benefits multiplied by the total of FTE's.

Accrued Pension and Post-Retirement Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 103,040	$ 112,837	$ 101,402	$ 112,411	$ 101,660	$ 95,302
Non-Union	$ 29,224	$ 42,828	$ 54,361	$ 60,263	$ 49,391	$ 46,820
Union	$ 422,248	$ 337,139	$ 366,427	$ 406,210	$ 428,568	$ 398,919
TOTAL	**$ 554,512**	**$ 492,804**	**$ 522,191**	**$ 578,884**	**$ 579,619**	**$ 541,041**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. These amounts are determined by CNPI's pension consultant.
3. Calculated based on average Accrued and Post Retirement Benefits multiplied by the total of FTE's.

Total Benefits (Current & Accrued) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 278,002	$ 265,675	$ 243,591	$ 257,446	$ 249,799	$ 246,938
Non-Union	$ 67,406	$ 77,844	$ 96,534	$ 106,679	$ 85,996	$ 89,070
Union	$ 808,546	$ 688,731	$ 746,906	$ 809,413	$ 887,182	$ 873,904
TOTAL	**$ 1,153,953**	**$ 1,032,251**	**$ 1,087,031**	**$ 1,173,537**	**$ 1,222,977**	**$ 1,209,912**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits were not included in 2009 Board Approved.
3. Calculated based on Average Yearly Benefits multiplied by the total of FTE's.

Total Compensation (Salary, Wages & Benefits) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 1,480,886	$ 1,378,644	$ 1,266,626	$ 1,321,702	$ 1,269,149	$ 1,292,984
Non-Union	$ 339,616	$ 352,980	$ 446,300	$ 460,573	$ 418,572	$ 432,078
Union	$ 3,074,028	$ 2,618,263	$ 2,890,319	$ 3,076,305	$ 3,416,810	$ 3,493,232
TOTAL	**$ 4,894,530**	**$ 4,349,887**	**$ 4,603,245**	**$ 4,858,579**	**$ 5,104,531**	**$ 5,218,294**

1. Calculated as Total Salary and Wages plus Total Benefits
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. Accrued pension and benefits included in this Total Compensation.

Compensation - Average Yearly Base Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 107,470	$ 96,555	$ 96,811	$ 100,591	$ 104,046	$ 106,931
Non-Union	$ 67,857	$ 66,302	$ 66,920	$ 68,559	$ 70,544	$ 72,511
Union	$ 63,582	$ 62,639	$ 64,229	$ 66,798	$ 68,904	$ 70,314

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on total actual salary and wages divided by the actual number of FTE's

Compensation - Average Yearly Overtime ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	$ 5,720	$ 3,305	$ 2,722	$ 4,010	$ 4,175	$ 4,300

1. 2009 Actual based on actual overtime paid. 2012 Bridge- 2013 Test based on 3% forecasted annual increases over 2011 total actual (see E4,T4,S1,App A) and averaged over actual number of union employees.
2. Executive, Management and Non-union are not paid overtime compensation.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.

Compensation - Average Yearly Incentive Pay($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 15,361	$ 17,095	$ 18,662	$ 19,535	$ 20,098	$ 20,464
Non-Union	$ 5,377	$ 7,719	$ 6,722	$ 5,952	$ 5,840	$ 6,269
Union	N/A	N/A	N/A	N/A	N/A	N/A

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Union is not paid incentive pay.

Compensation - Average Yearly Benefits ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 17,866	$ 27,129	$ 27,495	$ 29,059	$ 30,422	$ 30,074
Non-Union	$ 10,272	$ 20,943	$ 20,325	$ 22,461	$ 19,751	$ 20,457
Union	$ 11,817	$ 23,538	$ 23,330	$ 25,282	$ 25,630	$ 24,894

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits not were not included in 2009 Board Approved.

Compensation - Charged OM&A/Capitalized ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Total Compensation	$ 4,340,193	$ 4,349,887	$ 4,603,245	$ 4,858,579	$ 5,104,531	$ 5,218,294
Total Compensation Charged to OM&A	$ 3,255,144	$ 3,262,415	$ 3,452,434	$ 3,643,934	$ 3,828,398	$ 3,913,721
Total Compensation Capitalized	$ 1,085,048	$ 1,087,472	$ 1,150,811	$ 1,214,645	$ 1,276,133	$ 1,304,574

1. Accrued Pension and Post Retirement was not included in 2009 Board Approved, which is not comparable to other years.
2. CNPI capitalizes approximately 25% of total labour through direct charges to capital projects.
3. Total Compensation Capitalized was not reported on 2009 Compensation Table.

BDR 2012 ALLOCATED VERSION - PC

APPENDIX 2-K
Compensation Analysis - CNPI - PC

Number of Employees (FTE's including PT): *2012 BDR Report

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 BDR	2013 BDR
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	4.20	4.20	3.80	3.80	3.52	3.52
Non-Union	1.59	1.59	2.04	2.04	1.87	1.87
Union	12.54	12.54	13.72	13.72	14.84	15.05
TOTAL	18.33	18.33	19.56	19.56	20.22	20.43

1. The BDR Report methology was used in 2009 Board Approved. In 2009 FTE's exclude PTE's as per filing requirements. 2010-2013 FTE's include PTE's. In 2009 Actual there was no change in actual allocations. The API BDR Report was used for 2010 and 2011.
The BDR Report in Exhibit 4, Tab 5, Schedule 2, Appendix E was used for 2012 and 2013.
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. 2012 Total CNPI Dx on 2012 BDR Report is 67.40 - Breakdown to Mgmt, Non-Union and Union accordingly
4. While there is 1 new actual FTE being added to 2013 Test Year by CNPI, on an allocated basis using BDR Report approximately 0.7 FTE is being allocated to the CNPI distribution business units for the purpose of this Application.

Number of Part Time Employees (PTE's):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	1.47	1.5	1.5	1.5	1.5	1.5
TOTAL	**1.47**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**

1. PTE's based on actual number of part-time employees.

Total Salary and Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 515,522	$ 476,987	$ 438,444	$ 456,110	$ 436,864	$ 448,305
Non-Union	$ 116,662	$ 117,915	$ 149,900	$ 151,669	$ 142,533	$ 147,003
Union	$ 970,921	$ 826,942	$ 918,605	$ 971,525	$ 1,084,126	$ 1,122,569
TOTAL	**$ 1,603,105**	**$ 1,421,844**	**$ 1,506,949**	**$ 1,579,304**	**$ 1,663,523**	**$ 1,717,878**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on average salary, average OT and average incentive pay multiplied by the total of FTE's.

Current Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 74,984	$ 65,502	$ 102,748	$ 106,916	$ 116,909	$ 121,053
Non-Union	$ 16,363	$ 15,007	$ 24,054	$ 32,660	$ 32,619	$ 39,591
Union	$ 165,556	$ 150,682	$ 170,816	$ 178,562	$ 185,823	$ 193,817
TOTAL	**$ 256,903**	**$ 231,192**	**$ 297,617**	**$ 318,138**	**$ 335,352**	**$ 354,461**

1. Includes premuim cost of health, dental and LTD benefits, taxable benefits and pension contributions on behalf of employee made by the Company.
2. 2009 Actual - 20011 Actual based on actual costs. 2012 Bridge - 2013 Test Year based on quoted increases from CNPI benefits consultant of 5% increase for health, dental and LTD premiums.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
4. Calculated based on average Current Benefits multiplied by the total of FTE's.

Accrued Pension and Post-Retirement Benefits ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 44,160	$ 48,358	$ 43,458	$ 48,176	$ 43,569	$ 40,844
Non-Union	$ 12,525	$ 18,355	$ 23,298	$ 25,827	$ 21,168	$ 20,066
Union	$ 180,963	$ 144,488	$ 157,040	$ 174,090	$ 183,672	$ 170,965
TOTAL	**$ 237,648**	**$ 211,201**	**$ 223,796**	**$ 248,093**	**$ 248,409**	**$ 231,875**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. These amounts are determined by CNPI's pension consultant.
3. Calculated based on average Accrued and Post Retirement Benefits multiplied by the total of FTE's.

Total Benefits (Current & Accrued) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 119,144	$ 113,861	$ 104,396	$ 110,334	$ 107,057	$ 105,830
Non-Union	$ 28,888	$ 33,362	$ 41,372	$ 45,720	$ 36,855	$ 38,173
Union	$ 346,520	$ 295,171	$ 320,103	$ 346,891	$ 380,221	$ 374,530
TOTAL	**$ 494,551**	**$ 442,394**	**$ 465,871**	**$ 502,945**	**$ 524,133**	**$ 518,533**

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits were not included in 2009 Board Approved.
3. Calculated based on Average Yearly Benefits multiplied by the total of FTE's.

Total Compensation (Salary, Wages & Benefits) ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 634,665	$ 590,848	$ 542,840	$ 566,444	$ 543,921	$ 554,136
Non-Union	$ 145,550	$ 151,277	$ 191,272	$ 197,388	$ 179,388	$ 185,176
Union	$ 1,317,440	$ 1,122,113	$ 1,238,708	$ 1,318,416	$ 1,464,347	$ 1,497,100
TOTAL	**$ 2,097,655**	**$ 1,864,237**	**$ 1,972,819**	**$ 2,082,249**	**$ 2,187,656**	**$ 2,236,412**

1. Calculated as Total Salary and Wages plus Total Benefits
2. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
3. Accrued pension and benefits included in this Total Compensation.

Compensation - Average Yearly Base Wages ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 107,470	$ 96,555	$ 96,811	$ 100,591	$ 104,046	$ 106,931
Non-Union	$ 67,857	$ 66,302	$ 66,920	$ 68,559	$ 70,544	$ 72,511
Union	$ 63,582	$ 62,639	$ 64,229	$ 66,798	$ 68,904	$ 70,314

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Calculated based on total actual salary and wages divided by the actual number of FTE's

Compensation - Average Yearly Overtime ($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	N/A	N/A	N/A	N/A	N/A	N/A
Non-Union	N/A	N/A	N/A	N/A	N/A	N/A
Union	$ 5,720	$ 3,305	$ 2,722	$ 4,010	$ 4,175	$ 4,300

1. 2009 Actual based on actual overtime paid. 2012 Bridge- 2013 Test based on 3% forecasted annual increases over 2011 total actual (see E4,T4,S1,App A) and averaged over actual number of union employees.
2. Executive, Management and Non-union are not paid overtime compensation.
3. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.

Compensation - Average Yearly Incentive Pay($):

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 15,361	$ 17,095	$ 18,662	$ 19,535	$ 20,098	$ 20,464
Non-Union	$ 5,377	$ 7,719	$ 6,722	$ 5,952	$ 5,840	$ 6,269
Union	N/A	N/A	N/A	N/A	N/A	N/A

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Union is not paid incentive pay.

Compensation - Average Yearly Benefits ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Executive	N/A	N/A	N/A	N/A	N/A	N/A
Management	$ 17,866	$ 27,129	$ 27,495	$ 29,059	$ 30,422	$ 30,074
Non-Union	$ 10,272	$ 20,943	$ 20,325	$ 22,461	$ 19,751	$ 20,457
Union	$ 11,817	$ 23,538	$ 23,330	$ 25,282	$ 25,630	$ 24,894

1. As there are fewer than three FTE's in Executive, this category has been aggregated with Management.
2. Accrued Pension and Post Retirement Benefits not were not included in 2009 Board Approved.

Compensation - Charged OM&A/Capitalized ($)

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Total Compensation	$ 1,860,083	$ 1,864,237	$ 1,972,819	$ 2,082,249	$ 2,187,656	$ 2,236,412
Total Compensation Charged to OM&A	$ 1,395,062	$ 1,398,178	$ 1,479,614	$ 1,561,686	$ 1,640,742	$ 1,677,309
Total Compensation Capitalized	$ 465,021	$ 466,059	$ 493,205	$ 520,562	$ 546,914	$ 559,103

1. Accrued Pension and Post Retirement was not included in 2009 Board Approved, which is not comparable to other years.
2. CNPI capitalizes approximately 25% of total labour through direct charges to capital projects.
3. Total Compensation Capitalized was not reported on 2009 Compensation Table.

(OEB)

Operating Costs

Issue 4.8
Are the 2013 compensation costs and employee levels appropriate?

46. Ref: E4/T4/S1, Appendix A and B

On page 5 of Appendix B CNPI stated that an SAP Analyst is planned to be hired for June 2012 and an Electrical Engineer is planned to be hired for July 2012. Please provide up-to-date status of these hires. Please clarify if the Electrical Engineer is a non-union position or a management position.

RESPONSE:

CNPI confirms that the SAP Analyst was hired on May 22, 2012. CNPI also confirms that it is in the process of recruiting and hiring an Electrical Engineer, which will be a management position.

(OEB)

Operating Costs

Issue 4.8
Are the 2013 compensation costs and employee levels appropriate?

47. Ref: Ontario Municipal Employees Retirement System (OMERS) Pension Costs

OMERS announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013.

a) Please state whether or not CNPI's proposed pension costs include this increase.
b) If so, please provide the forecasted increase by years and the documentation to support the increases.
c) If not, please state how the applicant proposes to deal with this increase.
d) Please provide a projection of costs going forward.

RESPONSE:

a) CNPI's proposed pension costs include the OMERs actual increase in 2011, as well as the forecast increases.

b) CNPI has forecasted OMERs increases of approximately 3% for 2012 and 1% for 2013 for employees with Normal Retirement Age of 65. Attached is the documentation to support the increases

c) Not applicable.

d) See response to IR 47 (b) above.

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

13. [Ex.4/3/3/p.3]
Please provide greater details regarding the increase in part time labour allocations in the Test Year.

RESPONSE:

The reference to Exhibit 4, Tab 3, Schedule 3, page 3 refers to increased hours of part-time employees. While the number of PTEs remains consistent the hours worked fluctuates depending on departmental workload.

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

14. [Ex.4/4/1/p.4]
Please detail the current corporate targets and performance measures.

RESPONSE:

Attached please find the 2012 Corporate Short-Term Incentive Plan Targets and performance measures.

FortisOntario Inc.

2012 Corporate Short-term Incentive Plan Targets

Category	Weight	Measure	(50%) Minimum	(100%) Target	(150%) Maximum
Financial	30%	Consolidated Operating Costs ($'000)	Budget + 5% $27,633	Budget $26,317	Budget - 5% $25,001
	20%	Effectively Manage/Optimize Consolidated Capital Plan (Net) ($'000)	Subjective	Budget $31,867	Subjective
Customer Service [1]	15%	Customer Satisfaction	80%	83%	86%
Safety [2]	15%	# of High Risk Incidents (high risk lost time accidents + high risk near misses)	1	0	Subjective
	5%	# of Safety Field Observations for the Company	90% of total	100% of total	Subjective
Reliability	5%	The average duration of outages per customer (SAIDI) for CNPI and CE	3.30	2.20	1.10
	5%	The average frequency of outages per customer (SAIFI) for CNPI and CE	3.00	2.00	1.00
Reliability [3]	2.5%	The average duration of outages per customer (SAIDI) for API	8.00	7.00	6.00
	2.5%	The average frequency of outages per customer (SAIFI) for API	4.00	3.00	2.00

FORTISONTARIO INC.

2012 CORPORATE SHORT-TERM INCENTIVE PLAN TARGETS

Note 1: The 2012 overall customer satisfaction target has been set based on the three year average for all of the FortisOntario distribution territories with the exception of API since the company has only two years of survey history.

Note 2: The targeted number of high risk lost time incidents and high risks near misses for 2012 remains at zero.

The 100% target for 2012 for safety observations requires the completion of 348 planned safety observations.

Note 3: The 2012 SAIDI and SAIFI targets will be normalized to adjust for loss of supply outages outside the control of FortisOntario's electric distribution utilities. API will continue to be measured separately from the other FortisOntario service areas due to the unique characteristics of their rural distribution system.

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

15. [Ex.4/4/1/p.7]
Please provide a copy of current collective agreement with IBEW Local 636

RESPONSE:

As noted in evidence on page 6 of Exhibit 4, Tab 4, Schedule 1, the collective agreements have expired. Also as noted in evidence, CNPI is currently in negotiations with the IBEW and there are no current agreements in place, with the exception of IEBW (Fort Erie, Port Colborne) which ratified a new agreement on August 1, 2012. While the written agreement is not available, the increases are referred to in the response to EP 4, Operating Costs IR #4 a).

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

16.[Ex.4/4/1/A]
Please provide a separate Appendix 2-K-Compensation Analysis chart for each of a) CNPI-Fort Erie and Port Colborne and b) CNPI-EOP.

RESPONSE:

CNPI believes that there is a typo in the question and this it should read "please provide...for each of a) Fort Erie and *"EOP" (instead of Port Colborne)* and b) CNPI-*"Port Colborne" (instead of EOP)."* For these versions of Appendix 2K, please see the response to OEB IR 45.

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

17. [Ex.4/4/1/B/p.2]
Please provide the justification for creation of each new position since 2009.

RESPONSE:

As noted in evidence on page 2 of Exhibit 4, Tab 4, Schedule 1, Appendix B, the addition of 6.75 FTE's from 2009 Actual to the 2013 Test Year were required for the purposes of succession planning and/or to perform work to ensure continuity of operations and to maintain service levels to customers.

The justifications for the following positions are referred to opposite the additional FTE's below:

Date of Hire	Position	Justification
May 2010	Business Analyst	Required by IT to support the customer service business processes within SAP (ie, rate changes and configurations).
August 2010	Accountant	Required by Finance to work primarily on revenue analysis, managing regulatory compliance with respect to accounting treatments and regulatory asset/ liability analysis.
November 2010	Electrical Engineer	Required by Operations to provide technical support to CNPI operations (Lines, Substations, Metering, and System Control), and to participate in the development of the asset management plan, GIS, OMS, and distribution planning studies, and to support departmental safety initiatives.

June 2011	Regulatory Analyst	Required by Regulatory to work in providing regulatory and policy advice and to train as a successor to the incumbent Director who is entitled to take retirement in 2013.
June 2012	SAP Analyst	Required by IT to perform IT help desk ticketing and related services of which a substantial portion of the costs will be charged out to associates (Westario Power and Grimsby Power) under renewed IT services agreements.
July 2012	Electrical Engineer	Required by Operations to provide project design and project management for major engineering projects, and to develop and administer annual line and substation maintenance programs in accordance with Asset Management Plan.
January 2013	Operations Technician	Required by Operations to provide a hybrid role in the areas of SCADA systems and for succession planning (the incumbent is entitled to take retirement in August 2012), and substation maintenance. See response to SEC IR 18 below.

(SEC)

4. Operating Costs
4.8 Are the 2013 compensation costs and employee levels appropriate?

18. [Ex.4/4/1/B/p.2]
Please provide the expected retirement dates for each incumbent position that CNPI believes necessitates the addition of an Operations Technician.

RESPONSE:

The Operations Technician is a hybrid unionized position required in Operations. The individual will be required to install, test, maintain and repair all protection, communications, and metering systems at transmission and distribution facilities. As well, the Operations Technician will install and maintain SCADA systems, including all hardware and software. The Operations Technician will provide general support for Operations groups such as Substations and Metering, and perform technical studies and power quality investigations and prepare reports.

Accordingly, certain work for the Operations Technician will be in the area of SCADA operations, where the incumbent is eligible to retire in September 2012. Also, the work is in the area of substation maintenance where there are two electricians eligible to take retirement over the next three years.

(OEB)

Operating Costs

Issue 4.9
Is the test year forecast of property taxes appropriate?

No Interrogatories Posed

Canadian Niagara Power Inc.

EB-2012-0112

Response to Capital Structure and Cost of Capital Interrogatories

5. Capital Structure and Cost of Capital

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

(OEB)

Capital Structure and Cost of Capital

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

48. Ref: E5/T1/S1/p.2

On page 2 CNPI states that

> *In the second half of 2012, CNPI expects to borrow $8 million by way of affiliated long-term debt. The affiliated debt borrowing proceeds will primarily be used to finance the acquisition of the Port Colborne Hydro leased assets which closed on April 16, 2012. CNPI has used a deemed long-term debt rate of 4.41% for the 2013 Test …The Applicant recognizes that the deemed affiliated debt rate for the $8 million borrowing will be updated in accordance with Board guideline.*

a) Please provide the net book value ("NBV") and the purchase price premium (if applicable) of Port Colborne Hydro's legacy assets.
b) Please provide an explanation for the expected debt arrangements between CNPI and Fortis Ontario for the new debt in 2012. In particular, please explain how these terms reflect prudent and arms-length commercial arrangements that balance the cost to ratepayers and financial risk to CNPI and its shareholder.
c) Why are there no maturity date or repayment terms or fixed rates for these notes?
d) What alternative debt financing arrangements has CNPI considered for the new debt financing?
e) If available, please provide a copy of the debt instrument.

RESPONSE:

a) CNPI acquired the electricity distribution assets of Port Colborne Hydro Inc. on April 16, 2012 for an aggregate purchase price of $6.9 million. The net book value of the acquired electricity distribution assets was approximately $2.5 million. The cost of the premium is financed by the shareholders.

b) The expected interim debt arrangement for the new debt in 2012 is a promissory note similar to the existing promissory notes. The arrangement provides CNPI, and its customers, with flexible interim financing until the balance of the notes is sufficient enough to issue third party debt on reasonable terms. CNPI's shareholder is satisfied with both the level of risk and the terms of the debt arrangement. The intent is to finance long-term distribution assets with long-term debt. The short to medium financing is an interim step.

c) The promissory notes are held by FortisOntario, CNPI's parent company. CNPI and FortisOntario have the same senior management team. Issues with respect to repayment and maturity dates are negotiable. The interest rate is fixed until repayment.

d) CNPI is considering going to the market to issue long-term debt over the next 12 months. CNPI does have access to a $30 million revolving term credit facility which is used for general corporate purposes and to support letter of credit obligations. The borrowers under the agreement are CNPI, Algoma Power, and Cornwall Electric. The obligations of the borrowers under the credit facility are several and, for certainty, no borrower shall be obligated to repay the obligations of any other borrower. FortisOntario is not a borrower but a guarantor under the agreement. The credit facility is used to support the regular cash flow requirements of the borrowers. The unused balance of that facility at the end of June 2012 was $15.7 million.

e) A copy of the above noted Credit Agreement dated June 11, 2012 is attached.

EXECUTION VERSION

CANADIAN NIAGARA POWER INC.

and

CORNWALL STREET RAILWAY, LIGHT AND POWER COMPANY LIMITED

and

ALGOMA POWER INC.

as Borrowers

and

FORTISONTARIO INC.
as Guarantor

and

THE BANK OF NOVA SCOTIA

as Sole Lead Arranger,
Bookrunner and Administrative Agent

and

The Several Lenders from Time to Time Parties Hereto

CREDIT AGREEMENT

Dated as of June 11, 2012

FASKEN MARTINEAU
333 Bay Street
Suite 2400
Bay Adelaide Centre
P.O. Box 20
Toronto, Canada M5H 2T6

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SCHEDULE A INDIVIDUAL COMMITMENTS

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SCHEDULE F FORM OF CONVERSION NOTICE

SCHEDULE G INDEBTEDNESS FOR BORROWERED MONEY

CREDIT AGREEMENT dated as of June 11, 2012 among Canadian Niagara Power Inc., a corporation existing under the laws of the Province of Ontario ("**CNPI**"), Cornwall Street Railway, Light and Power Company Limited, a corporation existing under the laws of the Province of Ontario ("**Cornwall**"), Algoma Power Inc., a corporation existing under the laws of the Province of Ontario ("**API**" and together with CNPI and Cornwall, the "**Borrowers**" and individually, a "**Borrower**"), the lending institutions from time to time parties hereto as Lenders (each a "**Lender**" and, collectively, the "**Lenders**") and The Bank of Nova Scotia in its capacity as administrative agent of the Lenders (the "**Agent**").

WHEREAS the Borrowers have requested the Lenders to provide a certain revolving term credit facility for general corporate purposes, including, without limitation, to support letter of credit obligations of the Borrowers;

AND WHEREAS the obligations of the Borrowers under this Agreement shall be several and, for certainty, no Borrower shall be obligated to repay the obligations of any other Borrower;

AND WHEREAS the Guarantor has agreed to guarantee the obligations of each Borrower under this Agreement;

AND WHEREAS the Lenders are collectively willing to provide such credit facility to the Borrowers for the aforesaid purposes upon the terms and conditions contained herein.

NOW THEREFORE THIS AGREEMENT WITNESSES that, in consideration of the mutual covenants and agreements herein contained and for other good and valuable consideration (the receipt and sufficiency of which are hereby acknowledged), the parties hereto covenant and agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Defined Terms. The following defined terms shall for all purposes of this Agreement, or any amendment, substitute, supplement, replacement, addition or schedule hereto, have the following respective meanings unless the context otherwise specifies or requires or unless otherwise defined herein:

"**Affiliate**" shall have the meaning ascribed to the term "affiliate" in the CBCA in effect on the date hereof.

"**Agreement**" shall mean this Credit Agreement, as the same may be amended, modified, supplemented, restated or replaced from time to time.

"**API Notes**" means the unsecured notes of API issued pursuant to the API Trust Indenture as at the date hereof and any other such unsecured notes of API issued pursuant to the API Trust Indenture after the date hereof in accordance with Section 11.3(c)(v).

"**API Trust Indenture**" means the trust indenture made December 16, 2011 between API and Computershare Trust Company of Canada, as amended, modified or supplemented from time to time.

"**API Trust Indenture Indebtedness**" means the Indebtedness for Borrowed Money owing by API under the API Trust Indenture and the API Notes.

"**Applicable Margin**" means, at any particular time, with respect to Prime Rate Loans, 0.25%, and with respect to Bankers' Acceptances and Letters, 1.25%. Notwithstanding the foregoing, for so long as an Event of Default has occurred and is continuing, the Applicable Margin with respect to Prime Rate Loans shall be 2.25% per annum.

"**Authorization**" means, with respect to any Person, any authorization, order, permit, approval, grant, licence, consent, right, privilege, certificate, judgment, writ, injunction, award, determination, direction, decree, by-law, rule or regulation of any Governmental Authority having jurisdiction over such Person, whether or not having the force of Law.

"**Available Credit**" means, as at a particular date, the amount, if any, by which the amount of the Credit Facility as at the close of business on such date exceeds the amount of credit outstanding under the Credit Facility as at the close of business on such date.

"**BA Discount Rate**" shall mean:

(a) with respect to an issue of Bankers' Acceptances with a particular maturity date to be accepted by a Schedule I Lender hereunder, the CDOR Rate at or about 10:00 a.m. (Toronto time) on the date of issuance and acceptance of such Bankers' Acceptance for bankers' acceptances having a comparable face value and an identical maturity date to the face value and maturity date of such issue of Bankers' Acceptances;

(b) with respect to an issue of Bankers' Acceptances with a particular maturity date to be accepted by a Schedule II Lender or a Schedule III Lender hereunder, the lesser of:

(i) the annual interest rate equivalent to the arithmetic average of the discount rates of the Non-Schedule I Reference Lenders determined by them in accordance with their normal practice at or about 10:00 a.m. (Toronto time) on the date of issue and acceptance of such Bankers' Acceptances for bankers' acceptances having a comparable face value and an identical maturity date to the face value and maturity date of such Bankers' Acceptances; and

(ii) the CDOR Rate plus 0.1% per annum at or about 10:00 a.m. (Toronto time) on the date of issue and acceptance of such Bankers' Acceptances for bankers' acceptances having a comparable face value and an identical maturity date to the face value and maturity date of such Bankers' Acceptances; and

(c) with respect to a BA Rate Loan with a particular maturity date to be advanced by a Lender, the CDOR Rate plus 0.1% per annum at or about 10:00 a.m. (Toronto time) on the date of advance of such BA Rate Loan for bankers' acceptances having a comparable face value and an identical maturity date to the principal amount and maturity date of such BA Rate Loan.

"**BA Discounted Proceeds**" means, in respect of any Bankers' Acceptances to be accepted by a Lender on any day, an amount (rounded to the nearest whole cent and with one-half of one cent being rounded up) calculated on such day by multiplying:

(a) the aggregate face amount of such Bankers' Acceptances; by

(b) the price, where the price is determined by dividing one by the sum of one plus the product of:

(i) the BA Discount Rate which is applicable to such Bankers' Acceptance (expressed as a decimal); and

(ii) a fraction, the numerator of which is the number of days remaining in the term of such Bankers' Acceptances and the denominator of which is 365;

with the price as so determined being rounded up or down to the fifth decimal place and .000005 being rounded up.

"**BA Gross Proceeds**" means, with respect to particular Bankers' Acceptances:

(a) if a Borrower has elected that such Bankers' Acceptances be purchased by the Lenders accepting them, the aggregate BA Discounted Proceeds with respect thereto; or

(b) if a Borrower has elected that such Bankers' Acceptances be purchased by someone other than the Lenders accepting them, the aggregate purchase price therefor.

"**BA Net Proceeds**" means, with respect to a particular Bankers' Acceptance, the BA Gross Proceeds with respect thereto less the amount of the acceptance fees in respect of such Bankers' Acceptance calculated in accordance with Section 7.4.

"**BA Rate Loan**" shall have the meaning ascribed thereto in Section 3.5.

"**Bankers' Acceptance**" means (x) a depository bill under the *Depository Bills and Notes Act* (Canada) or (y) a bill of exchange under the *Bills of Exchange Act* (Canada), in either case (a) drawn by a Borrower and accepted by a Lender, (b) denominated in Canadian dollars, (c) having a term of less than one month or of one, two, three, six or twelve months (subject to availability and subject to the right of the Agent, in its discretion, to

restrict the term or maturity dates applicable to Bankers' Acceptances) and (d) issued and payable only in Canada.

"**Branch of Account**" means the branch of the Borrowers located at 720 King Street West, 2nd Floor, Toronto, Ontario, Canada M5V 2T3, or such other branch of the Agent located in Canada as the Borrowers and the Agent may agree upon.

"**Business Day**" means any day that is not a Saturday, Sunday or other day on which commercial banks in Toronto, Ontario are authorized or required by Law to remain closed.

"**Canadian Qualified Lender**" means a Lender which (i) is not a "non-resident" within the meaning of the Tax Act, or (ii) is an "authorized foreign bank" within the meaning of the Tax Act, but only in respect of an amount payable with respect to any outstanding credit or portion thereof that is paid or credited in respect of its "Canadian banking business" within the meaning of the Tax Act.

"**Capital Adequacy Guideline**" means Guideline A of the Office of the Superintendent of Financial Institutions Canada dated October, 1995 with respect to capital adequacy requirements of Canadian banks, as from time to time amended, revised or reissued.

"**Capitalization**" of a particular Borrower means, on any date, an amount equal to Debt of such Borrower on such date plus Shareholders' Equity of such Borrower on such date.

"**CBCA**" means the *Canada Business Corporations Act*.

"**CDH**" means those assets owned by the Guarantor comprised of a 5 MW district heating plant in Cornwall, Ontario and the related facilities.

"**CDOR Rate**" shall mean, as of any day with respect to an issue of Bankers' Acceptances or a BA Rate Loan with a particular maturity date, the average interest rate equal to:

(a) the average of the rates for Canadian dollar bankers' acceptances quoted at approximately 10:00 a.m. (Toronto time) on such day on the Reuters Monitor Money Rates Service, CDOR page "Canadian Interbank Bid BA Rates"; and

(b) if such rate is not available on such day, the rate for such date will be the annual discount rate (rounded upward to the nearest whole multiple of 1/100 of 1%) as of 10:00 a.m. (Toronto time) on such day at which the Agent is then offering to purchase Canadian dollar bankers' acceptances with an identical maturity date accepted by it.

"**Closing Date**" means June 11, 2012.

"**Control**" means, in respect of a particular Person, the possession, directly or indirectly, of the power to direct or cause the direction of the management or the policies of such

Person, whether through the ability to exercise voting power, by contract or otherwise. "**Controlling**" and "**Controlled**" have meanings correlative thereto.

"**Conversion Notice**" shall have the meaning ascribed thereto in Section 6.3.

"**Credit Excess**" means, as at a particular date, the amount, if any, by which the amount of credit outstanding under the Credit Facility as at the close of business on such date exceeds the amount of the Credit Facility as at the close of business on such date.

"**Credit Facility**" means the revolving term credit facility established by the Lenders in favour of the Borrowers pursuant to Section 2.1.

"**Debt**" of a particular Borrower means, on any date, an amount equal to the aggregate of all Indebtedness for Borrowed Money of such Borrower on such date, determined in accordance with GAAP, plus the redemption amount of all shares of such Borrower which are retractable or redeemable at the option of the holder on such date.

"**Debt to Capitalization Ratio**" of a particular Borrower means, on any date, the ratio of Debt of such Borrower on such date to Capitalization of such Borrower on such date.

"**Default**" means any event or condition which constitutes an Event of Default or which, upon notice, lapse of time or both, would, unless cured or waived, become an Event of Default.

"**Designated Account**" means, with respect to transactions under the Credit Facility and referable to a particular Borrower, an account of such Borrower maintained by the Agent at the Branch of Account for the purposes of transactions under the Credit Facility.

"**$**" denotes Canadian dollars, unless otherwise referenced.

"**Draft**" means any draft, bill of exchange, receipt, acceptance, demand or other request for payment drawn or issued under or in respect of a Letter.

"**Drawdown Notice**" shall have the meaning ascribed thereto in Section 4.1.

"**Environmental Laws**" means all Laws relating in any way to the protection of the environment, the preservation or reclamation of natural resources, or the management, release or threatened release of any Hazardous Material or to occupational health and safety matters.

"**Environmental Liability**" means any liability, contingent or otherwise (including any liability for damages, costs of environmental remediation, fines, penalties or indemnities), of the Borrower directly or indirectly resulting from or based upon (a) violation of any Environmental Law, (b) the generation, use, handling, transportation, storage, treatment or disposal of any Hazardous Materials, (c) exposure to any Hazardous Materials, (d) the release or threatened release of any Hazardous Materials into the environment, or (e) any contract, agreement or other consensual arrangement pursuant to which liability is assumed or imposed with respect to any of the foregoing.

"**Event of Default**" shall have the meaning ascribed thereto in Section 13.1.

"Exchange Equivalent" means, as of any particular date, with reference to any amount (the "original amount") expressed in Canadian dollars or United States dollars (the "original currency"), the amount expressed in the other currency which would be required to buy the original amount of the original currency using the noon spot rate quoted by the Agent for such date and for comparable amounts of such original currency.

"**Existing CIBC Facility Agreements**" means collectively, the credit agreement dated August 14, 2003 between CNPI as borrower and Canadian Imperial bank Of Commerce as lender as amended by amending agreements dated July 29, 2009, August 6, 2010 and September 16, 2011 and the credit agreement dated August 6, 2003 between Cornwall as borrower and Canadian Imperial bank Of Commerce as lender as amended by amending agreements dated January 21, 2004, November 15, 2004, June 12, 2008, July 29, 2009, August 6, 2010 and September 16, 2011.

"**Existing CIBC Indebtedness**" means (w) the $10,000,000 letter of credit in favour of HQ Energy Marketing Inc. issued at the request of Cornwall, (x) the $1,800,000 letter of credit in favour of IESO issued at the request of API, (y) the $1,500,000 letter of credit in favour of IESO issued at the request of CNPI and (z) the $1,000,000 letter of credit in favour of IESO issued at the request of CNPI.

"**Fee Letter**" means the fee letter dated June 11, 2012 between the Borrowers and the Agent, as the same may be amended, modified, supplemented or replaced from time to time.

"**Financial Letters**" means standby letters of credit or other equivalent instruments issued by the Fronting Lender, in each case acting on the request and on the credit of a Borrower, which serve as financial guarantees to stand behind or back the financial obligations of such Borrower and to satisfy those obligations should such Borrower fail to do so, and which are treated as direct credit substitutes for the purposes of the Capital Adequacy Guideline.

"**Financial Officer**" means the Vice-President, Finance; Chief Financial Officer; Manager, Finance; or other officers of a Borrower having similar responsibilities from time to time.

"**Fiscal Quarter**" means any of the three-month fiscal periods of a particular Obligor ending on the last day of March, June, September and December in each year.

"**Fiscal Year**" means any of the twelve-month fiscal periods of a particular Obligor ending on the last day of December in each year.

"**Fronting Lender**" means the Agent or any Lender who is prepared to act as Fronting Lender hereunder with the consent of the Agent and the Borrowers.

"**GAAP**", with respect to a particular Obligor, means generally accepted accounting principles (including International Financial Reporting Standards, as applicable) in effect

from time to time, at the option of such Obligor, in Canada or in the United States of America.

"**Governmental Authority**" means the Government of Canada, any other nation or any political subdivision thereof, whether provincial, state or local, and any agency, authority, instrumentality, regulatory body, court, central bank, fiscal or monetary authority or other authority regulating financial institutions and any other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government, including the Bank Committee on Banking Regulation and Supervisory Practices of the Bank of International Settlements and the Ontario Regulator.

"**Guarantee**" of or by any Person means any obligation, contingent or otherwise, of the Person guaranteeing or having the economic effect of guaranteeing any Indebtedness for Borrowed Money of any other Person.

"**Guarantor**" means FortisOntario Inc., a corporation incorporated under the laws of the Province of Ontario.

"**Hazardous Materials**" means all explosive or radioactive substances or wastes and all hazardous or toxic substances, wastes or other pollutants, including without limitation, petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls, radon gas, infectious or medical wastes and all other substances or wastes of any nature regulated pursuant to any Environmental Law.

"**Indebtedness for Borrowed Money**" of any Person includes, without duplication, (a) all obligations of such Person for borrowed money or with respect to advances of any kind, (b) all obligations of such Person evidenced by bonds, debentures, notes, letters of credit or similar instruments, (c) all obligations of such Person upon which interest charges are customarily paid, (d) all capital lease obligations of such Person, (e) all obligations, contingent or otherwise, of such Person in respect of bankers' acceptances, letters of credit and letters of guarantee, and (f) all Guarantees by such Person of Indebtedness for Borrowed Money of others in each case determined in accordance with GAAP; provided that, for greater certainty, trade payables do not constitute Indebtedness for Borrowed Money.

"**Individual Commitment**" means, with respect to a particular Lender and the Credit Facility, the amount set forth in Schedule A attached hereto, as reduced or amended from time to time pursuant to Sections 2.4, 8.3 and 16.6, as the individual commitment of such Lender under the Credit Facility, provided that, upon the termination of the Credit Facility pursuant to Section 2.5, the Individual Commitment of each Lender under the Credit Facility shall thereafter be equal to the amount of outstanding credit extended to the Borrower by such Lender under the Credit Facility immediately prior to the termination of the Credit Facility.

"**Issuance Date**" means, with respect to a particular Letter, the date of issuance of such Letter pursuant to this Agreement.

"**Laws**" means all federal, provincial, municipal, foreign and international statutes, codes, ordinances, decrees, treaties, rules, regulations, guidelines, municipal by-laws, judicial or arbitral or administrative or ministerial or departmental or regulatory judgments, orders, directives, decisions, rulings or awards or any provisions of the foregoing, including general principles of common and civil law and equity, and all policies, practices and guidelines of any Governmental Authority binding on or affecting the Person referred to in the context in which such word is used; and "**Law**" means any one or more of the foregoing.

"**Letter**" means a Financial Letter or a Performance Letter, each being denominated in Canadian dollars, having a term of not more than one year, being renewable in the sole discretion of the Fronting Lender, being issued to a named beneficiary acceptable to the Fronting Lender and being otherwise in a form satisfactory to the Fronting Lender.

"**Lien**" means, with respect to any property or asset, (a) any mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge, security interest, adverse claim or defect of title in, on or of such asset, (b) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset, (c) in the case of securities, any purchase option, call or similar right of a third party with respect to such securities, (d) any netting arrangement, defeasance arrangement or reciprocal fee arrangement, and (e) any other arrangement having the effect of providing security.

"**Loan Documents**" means this Agreement, the Fee Letter and all other documents, instruments and agreements executed and delivered by the Obligors in favour of the Agent, the Lenders or any of them in connection with this Agreement.

"**Loan Obligations**" of a particular Obligor means all present and future indebtedness, liabilities and obligations, direct or indirect, matured or contingent, of such Obligor to the Lenders, the Agent or any of them under the Loan Documents to which such Obligor is a party.

"**Loans**" means Prime Rate Loans and BA Rate Loans.

"**Majority Lenders**" means, at any particular time, such group of Lenders whose Individual Commitments aggregate at least 66 2/3% of the aggregate of the Individual Commitments of all the Lenders at such time.

"**Material Adverse Change**" means, in respect of any Obligor, any change (including, without limitation, any legislative or regulatory change) having a material adverse effect on:

(a) the business, assets, liabilities, operations, results of operations or condition (financial or other) of such Obligor or which would reasonably be expected to result in an impairment of the ability of such Obligor to perform any of its Loan Obligations; or

(b) the validity or enforceability of any of the Loan Documents to which such Obligor is a party or the rights and remedies of the Agent, the Lenders or any of them thereunder,

as determined by the Majority Lenders, acting reasonably.

"**Maturity Date**" means June 11, 2013.

"**Non-Schedule I Reference Lenders**" means up to two Schedule II Lenders and Schedule III Lenders designated as such by the Agent and the Borrowers.

"**Obligors**" means the Borrowers and the Guarantor and "**Obligor**" means any one of them.

"**OEB Affiliate Relationships Code**" means the Affiliate Relationships Code for Electricity Distributors and Transmitters (EB-2007-0662).

"**Ontario Regulator**" means the Ontario Energy Board, and with respect to Cornwall only, also the City of Cornwall.

"**Order**" means an order, judgment, injunction or such other determination of a Governmental Authority restricting payment by a Lender under and in accordance with a Letter or extending a Lender's liability under a Letter beyond the expiration date stated therein.

"**Performance Letters**" means performance standby letters of credit, performance bonds, bid bonds or other equivalent instruments issued by the Fronting Lender, in each case acting on the request and on the credit of a Borrower, which serve as guarantees that support or back such Borrower's particular performance obligations (but specifically excluding financial obligations) and which are treated as transaction-related contingencies for the purposes of the Capital Adequacy Guideline.

"**Permitted Liens**" means, as of any particular time with respect to any Obligor, any of the following Liens, privileges, charges, encumbrances or other rights:

(a) Liens or privileges for Taxes, rates, assessments or governmental charges or levies which are not due or delinquent or which are due and delinquent but the validity of which is being contested in good faith by appropriate action promptly initiated and diligently conducted and do not in the aggregate materially adversely affect any Obligor's financial condition or operations;

(b) Liens for the excess of the amount of any past due Taxes for which a final assessment has not been received over the amount of such Taxes as estimated and paid by any Obligor acting prudently and reasonably;

(c) undetermined or inchoate liens, including statutory Liens, arising or potentially arising which have not at the time been filed or registered in

accordance with applicable Law or Environmental Law or served upon any Obligor or which, although filed and registered, relate to obligations not due or delinquent the validity of which is being contested in good faith by appropriate action promptly initiated and diligently conducted and do not in the aggregate materially adversely affect such Obligor's financial condition or operations;

(d) easements, rights of way, servitudes, licences, zoning or other similar rights in real property (including easements, rights of way and servitudes for sewers, drains, steam, gas and oil pipelines, gas and water mains, electric light and power and telephone or telegraph lines and other forms of communication, conduits, poles, wires or other incidental equipment) granted to or reserved or taken by other Persons which will not in the aggregate materially adversely affect the use of the property for the purposes for which it is held by any Obligor and mortgages of and other Liens against the said easements, rights of way, servitudes, licences, zoning or other similar rights in real property;

(e) the rights reserved to or vested in municipalities or governmental or other public authorities or agencies by statutory provisions or by the terms of leases, licences, franchises, grants or permits, which affect any land, to terminate the leases, licences, franchises, grants or permits or to require annual or other periodic payments as a condition of the continuance thereof;

(f) reservations, limitations, conditions, exceptions and provisos in any original grants from the Crown of any land or interest therein, statutory exceptions to title, and reservations of mineral rights (including coal, oil and natural gas) in any grants from the Crown or from any other predecessors in title;

(g) security given to public utilities or to any municipalities or governmental or other public authorities when required by the utility, municipality, governmental or other public authority in connection with the supply of services or utilities to any Obligor;

(h) Liens and privileges arising out of claims filed, judgments or awards with respect to which (i) the validity of which is being contested in good faith by appropriate action promptly initiated and diligently conducted and do not in the aggregate materially adversely affect any Obligor's financial condition or operations or (ii) an appeal or proceeding for review is being prosecuted in good faith and with respect to which there shall have been secured a stay of execution pending the appeal or proceeding for review or for which security acceptable to the Agent has been posted by such Obligor;

(i) Liens or deposits in connection with bids, tenders, contracts or expropriation proceedings of any Obligor or to secure utilities, workers' compensation, unemployment insurance or other similar statutory assessments, pension or post-retirement benefits or to secure costs of litigation when required by Law, and surety or appeal bonds in connection with such litigation;

(j) warehouseman's, carriers' or other similar common law Liens or privileges, where the action to enforce the same has not proceeded to final judgment, is being defended in good faith by any Obligor and in respect of which it shall have set aside on its books reserves required in accordance with GAAP;

(k) any other Liens or privileges or other title irregularities, encroachments or encumbrances of a nature similar to the foregoing which are of a minor nature and will not in the aggregate materially and adversely affect the use of the property for the purposes for which it is held by any Obligor;

(l) deposits of cash or securities (i) posted in the ordinary course of business other than in relation to Indebtedness for Borrowed Money or (ii) in connection with any Liens referred to in paragraphs (a), (c) and (h) above;

(m) assignments of insurance provided to landlords (or their mortgagees) pursuant to the terms of any lease and Liens or rights reserved in or exercised under any lease for rent or compliance with the terms of such lease;

(n) mechanics', workers', repairers' or other like possessory Liens, arising in the ordinary course of business for amounts the payment of which is either not delinquent or is being contested in good faith by appropriate proceedings;

(o) subject to paragraph (w), Liens on personal property created, issued or assumed to secure any indebtedness and any replacement or renewal thereof, in respect of conditional sales contracts, hire-purchase agreements, chattel mortgages, title retention agreements and leases in the nature of title retention agreements and other similar instruments containing or creating Liens upon any personal property owned by any Obligor to secure the purchase price of such property or the repayment of money borrowed to pay such purchase price or any vendor's lien or privilege on such property securing the whole or any part of such purchase price;

(p) subject to paragraph (w), Liens in connection with indebtedness in respect of services rendered or to be rendered or goods or products provided or to be provided to any Obligor, including rent and other payments under leases, contracts, hire-purchase agreements and agreements for sale;

(q) plans of subdivision, site plans, municipal agreements or restrictive covenants affecting the use to which lands may be put, provided that such covenants are complied with and do not materially detract from the value of the land concerned or materially impair its use in the operation of the business of any Obligor;

(r) rights and interests created by notice registered by any Department of Highways or similar authorities with respect to proposed highways and which do not materially detract from the value of the land concerned or materially impair its use in the operation of the business of any Obligor;

(s) zoning and building laws and ordinances, municipal by-laws (including site specific by-laws) and regulations;

(t) certificates of pending litigation that may be registered against any real property or interests therein of any Obligor in respect of any action or proceeding against such Obligor or in which it is a defendant, but with respect to which action or proceeding no judgment, award or attachment against such Obligor has been granted or made and which such Obligor is defending in good faith and in respect of which such Obligor has posted security satisfactory to the Agent, acting reasonably;

(u) the granting by any Obligor in the ordinary course of its business of any lease, sub-lease, tenancy or right of occupancy to any Person in respect of property owned or leased by such Obligor;

(v) subject to paragraph (w), Purchase Money Security Interests;

(w) any other Liens which secure indebtedness or other obligations, provided that the aggregate indebtedness or other obligations secured by all Liens contemplated by this paragraph (w), together with all Liens contemplated by paragraphs (o), (p) and (v) above, shall not exceed $2,500,000 at any time;

(x) any Lien granted by any Obligor with the prior written consent of the Majority Lenders;

(y) any netting agreement, defeasance agreement or reciprocal fee arrangement and any other arrangement having the effect of providing security, in each case that was in existence on the date hereof; and

(z) any other Lien which, as of the Closing Date, is, in the case of lands comprising the land rights which are held by way of fee simple estate, registered against the title to those lands or, in the case of the other land rights, registered in priority to the land rights where the foregoing would not reasonably be expected to, in the aggregate, materially adversely affect the Borrower's financial condition or operations.

"**Person**" includes any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"**Prime Rate**" means the greater of (i) the variable rate of interest per annum equal to the rate of interest determined by the Agent from time to time as its prime rate for Canadian dollar loans made by the Agent in Canada from time to time, being a variable per annum reference rate of interest adjusted automatically upon change by the Agent, calculated on the basis of a year of 365 days or 366 days in the case of a leap year and (ii) the sum of (a) the CDOR Rate for a one month term and (b) ½ of 1% per annum.

"**Prime Rate Loan**" means monies lent by the Lenders to a Borrower hereunder in Canadian dollars and upon which interest accrues at a rate referable to the Prime Rate.

"**Pro Rata Share**" means, at any particular time with respect to a particular Lender, the ratio of the Individual Commitment of such Lender at such time to the aggregate of the Individual Commitments of all of the Lenders at such time.

"**Purchase Money Obligation**" means any Indebtedness for Borrowed Money, assumed as part of, or issued or incurred to provide funds to pay, in whole or in part, the purchase price, which shall be deemed to include any cost of installation, of movable or immovable property acquired before or after the date of this Agreement. In the case of property so acquired, the purchase price shall be deemed to include expenditures made for any repairs or alterations, construction, development or improvements performed thereon or added thereto within a period of 12 months after the acquisition thereof.

"**Purchase Money Security Interest**" means any Lien on a property or asset created, issued or assumed to secure the purchase price giving rise to the Purchase Money Obligation in respect of such property or asset and includes any extension, renewal or refunding thereof so long as the principal amount outstanding on the date of such extension, renewal or refunding is not increased; provided, however, that such encumbrance does not exceed the purchase price giving rise to the Purchase Money Obligation and is limited to the property acquired in connection with the assumption, issuance or incurring of such Purchase Money Obligation and is created, issued or assumed concurrently with or within 180 days following the acquisition of such property, except in the case of property on which repairs or alterations, construction, development or improvements are performed or added after the acquisition thereof, in which case the same shall be created or issued within a period of 180 days after the acquisition of such property.

"**Responsible Officer**" means, with respect to any corporation, the chairman, the president, any vice president, the secretary, the chief executive officer or the chief operating officer, and, in respect of financial or accounting matters, any Financial Officer of such corporation; unless otherwise specified, all references herein to a Responsible Officer mean a Responsible Officer of a Borrower.

"**Restricted Payment**" means, with respect to any Person, any payment by such Person (i) of any dividends, other than stock dividends, on any shares of its capital, (ii) on

account of, or for the purpose of setting apart any property for a sinking or other analogous fund for, the purchase, redemption, retirement or other acquisition of any shares of its capital or any warrants, options or rights to acquire any such shares, or the making by such Person of any other distribution in respect of any shares of its capital, or (iii) of any principal of or interest or premium on or of any indebtedness of such Person ranking in right of payment subordinate to any liability of such Person under the Loan Documents, or the payment of any amount in respect of a sinking or analogous fund or defeasance fund for any such indebtedness.

"**Rollover Notice**" shall have the meaning ascribed thereto in Section 5.2.

"**Schedule I Lenders**" shall mean, at any time, the Lenders that are listed in Schedule I to the *Bank Act* (Canada) at such time.

"**Schedule II Lenders**" shall mean, at any time, the Lenders that are listed in Schedule II to the *Bank Act* (Canada) at such time.

"**Schedule III Lenders**" shall mean, at any time, the Lenders that are listed in Schedule III to the *Bank Act* (Canada) at such time.

"**Shareholders' Equity**" of a particular Borrower means, on any date, the shareholders' equity of such Borrower on such date, determined in accordance with GAAP.

"**Subsidiary**" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity the accounts of which would be consolidated with those of the parent in the parent's consolidated financial statements if such financial statements were prepared in accordance with GAAP as of such date, as well as any other corporation, limited liability company, partnership, association or other entity (a) of which securities or other ownership interests representing more than 50% of the equity or more than 50% of the ordinary voting power or, in the case of a partnership, more than 50% of the general partnership interests are, as of such date, owned, Controlled or held by the parent or one or more subsidiaries of the parent, or (b) that is, as of such date, otherwise Controlled by the parent or one or more subsidiaries of the parent.

"**Tax Act**" means the *Income Tax Act* (Canada), as amended from time to time, and regulations promulgated thereunder.

"**Taxes**" means all taxes, charges, fees, levies, imposts and other assessments, including all income, sales, use, goods and services, value added, capital, capital gains, alternative, net worth, transfer, profits, withholding, payroll, employer health, excise, real property and personal property taxes, and any other taxes, customs duties, fees, assessments, or similar charges in the nature of a tax including Canada Pension Plan and provincial pension plan contributions, unemployment insurance payments and workers' compensation premiums, together with any instalments with respect thereto, and any interest, fines and penalties with respect thereto, imposed, levied, collected, withheld or assessed by any Governmental Authority (including federal, state, provincial, municipal and foreign Governmental Authorities), and whether disputed or not.

1.2 Other Usages. References to "this Agreement", "the agreement", "hereof", "herein", "hereto" and like references refer to this Credit Agreement and not to any particular Article, Section or other subdivision of this Agreement. Any references herein to any agreements or documents shall mean such agreements or documents as amended, supplemented or otherwise modified from time to time in accordance with the terms hereof and thereof.

1.3 Plural and Singular. Where the context so requires, words importing the singular number shall include the plural and vice versa.

1.4 Headings. The division of this Agreement into Articles and Sections and the insertion of headings in this Agreement are for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

1.5 Currency. Unless otherwise specified herein, all statements of or references to dollar amounts in this Agreement shall mean lawful money of Canada.

1.6 Applicable Law. This Agreement shall be governed by and construed in accordance with the Laws of the Province of Ontario and the federal Laws of Canada applicable therein. Any legal action or proceeding with respect to this Agreement may be brought in the courts of the Province of Ontario and, by execution and delivery of this Agreement, the parties hereby accept for themselves and in respect of their property, generally and unconditionally, the non-exclusive jurisdiction of the aforesaid courts. Nothing herein shall limit the right of any party to serve process in any manner permitted by Law or to commence legal proceedings or otherwise proceed against any other party in any other jurisdiction.

1.7 Time of the Essence. Time shall in all respects be of the essence of this Agreement.

1.8 Non-Business Days. Whenever any payment to be made hereunder shall be stated to be due or any action to be taken hereunder shall be stated to be required to be taken on a day other than a Business Day, such payment shall be made or such action shall be taken on the next succeeding Business Day and, in the case of the payment of any amount, the extension of time shall be included for the purposes of computation of interest, if any, thereon.

1.9 Consents, Approvals and Documentation. Whenever the consent or approval of a party hereto is required in a particular circumstance, unless otherwise expressly provided for herein, such consent or approval shall not be unreasonably withheld or delayed by such party.

1.10 Amount of Credit. Any reference herein to the amount of credit outstanding shall mean, at any particular time:

(a) in the case of a Prime Rate Loan or a BA Rate Loan, the principal amount thereof at such time;

(b) in the case of a Bankers' Acceptance, the face amount thereof at such time; and

(c) in the case of a Letter, the aggregate contingent liability of the Fronting Lender thereunder.

1.11 Schedules. Each and every one of the schedules which is referred to in this Agreement and attached to this Agreement shall form a part of this Agreement.

1.12 Statute References. Any reference in this Agreement to any statute or any Section thereof shall, unless otherwise expressly stated, be deemed to be a reference to such statute or Section as amended, restated or re-enacted from time to time.

1.13 Paramountcy. In the event of any conflict or inconsistency between a particular provision of any other Loan Document and a particular provision of this Agreement and to the extent said provision of such other Loan Document purports to impose obligations on any Obligor that are more onerous than the said provision of this Agreement, then the said provision of this Agreement shall prevail and be paramount.

1.14 GAAP. Any references in this Agreement to GAAP "consistently applied" shall be deemed to be qualified, to the extent necessary, to changes in application as a result of any transition from generally accepted accounting principles in Canada to generally accepted accounting principles in the United States of America and vice versa (including International Financial Reporting Standards).

1.15 Extension of Credit. For the purposes hereof, each drawdown, rollover and conversion shall be deemed to be an extension of credit to the relevant Borrower hereunder.

1.16 Several Obligations. Each Borrower's Loan Obligations under the Loan Documents to which it is a party are several obligations and, for certainty, shall not constitute joint and several obligations. Additionally, for further certainty, the Guarantee granted by the Guarantor under this Agreement is a Guarantee of each Borrower's Loan Obligations. All provisions of this Agreement that refer to a Borrower or Borrowers shall be construed as applicable to a particular Borrower as if it was the sole Borrower under this Agreement and no Default or Event of Default by one Borrower shall constitute a Default or Event of Default by any other Borrower and no act or omission by a particular Borrower shall affect the rights of obligations of any other Borrower under this Agreement.

ARTICLE 2
CREDIT FACILITY

2.1 Establishment of Credit Facility. Subject to the terms and conditions hereof, the Lenders hereby establish in favour of the Borrowers a revolving term credit facility (the "**Credit Facility**") in the amount of $30,000,000.

2.2 Credit Restrictions. Notwithstanding any other provision hereof, the Borrowers shall be entitled to obtain credit by way of BA Rate Loans or Bankers' Acceptances only in such amounts so as to ensure that no Lender is required to make a BA Rate Loan for a principal amount other than an integral multiple of $1,000 or to accept a Bankers' Acceptance having a face amount other than an integral multiple of $1,000. Any extension of credit by way of Bankers' Acceptance shall be in a minimum of $500,000 and otherwise in multiples of $100,000.

2.3 Lenders' Commitments. Subject to the terms and conditions hereof, the Lenders severally agree to extend credit to the Borrowers hereunder from time to time provided that the

aggregate amount of credit extended by each Lender under the Credit Facility shall not at any time exceed the Individual Commitment of such Lender and further provided that the aggregate amount of credit outstanding under the Credit Facility shall not at any time exceed the amount of the Credit Facility referred to in Section 2.1 as the same may be reduced pursuant to Section 2.4. All credit requested under the Credit Facility shall be made available to the relevant Borrower contemporaneously by all of the Lenders. Each Lender shall provide to the relevant Borrower its Pro Rata Share of each credit in accordance with the terms hereof, whether such credit is extended by way of drawdown, rollover or conversion. No Lender shall be responsible for any default by any other Lender in its obligation to provide its Pro Rata Share of any credit nor shall the Individual Commitment of any Lender with respect to the Credit Facility be increased as a result of any such default of another Lender in extending credit thereunder. The failure of any Lender to make available to any Borrower its Pro Rata Share of any credit under the Credit Facility shall not relieve any other Lender of its obligation hereunder to make available to the Borrower its Pro Rata Share of such credit thereunder.

2.4 Reductions of Credit Facility. The Borrowers may, from time to time and at any time, by three Business Days' notice in writing to the Agent, permanently reduce the amount of the Credit Facility to the extent it is not utilized; provided, however, that any such permanent reduction of the amount of the Credit Facility shall be by an amount of no less than $1,000,000 and otherwise in multiples of $100,000. The amount of the Credit Facility will not be reduced by any repayment or prepayment pursuant to Section 9.2 or pursuant to Section 9.3 but will be permanently reduced by any repayment or prepayment pursuant to Section 9.1, each such reduction to be in an amount equal to the amount of the repayment or prepayment and to be effective from the time of the repayment or prepayment. Any repayment of outstanding credit under the Credit Facility which forms part of any rollover under Article 5 or any conversion from one type of credit to another type of credit under Article 6 shall not cause any reduction in the amount of the Credit Facility. Upon each permanent reduction in the amount of the Credit Facility, the Individual Commitment of each Lender shall thereupon be reduced by an amount equal to such Lender's Pro Rata Share of the amount by which the Credit Facility is permanently reduced.

2.5 Termination of Credit Facility

(a) The Credit Facility shall terminate upon the earliest to occur of:

(i) the Maturity Date;

(ii) the date on which the amount of the Credit Facility has been permanently reduced to zero pursuant to Section 2.4; and

(iii) the termination of the Credit Facility pursuant to Section 13.1.

(b) Upon the termination of the Credit Facility, the right of the Borrowers to obtain any credit under the Credit Facility and all of the obligations of the Lenders to extend credit under the Credit Facility shall automatically terminate.

ARTICLE 3
PROVISIONS RELATING TO CREDITS

3.1 Types of Credit Availments. Subject to the terms and conditions hereof, the Borrowers may obtain credit under the Credit Facility by way of one or more Bankers' Acceptances, BA Rate Loans, Prime Rate Loans and Letters. For certainty, the Borrowers may obtain the full amount of the Credit Facility by way of one or more Letters.

3.2 Funding of Prime Rate Loans. Each Lender shall make available to the Agent its Pro Rata Share of the principal amount of each Prime Rate Loan under the Credit Facility prior to noon (Toronto time) on the date of the extension of credit. The Agent shall, upon fulfilment by the Borrowers of the terms and conditions set forth in Article 12, make such funds available to the relevant Borrower on the date of the extension of credit by crediting the Designated Account in immediately available funds unless otherwise irrevocably authorized and directed in the Drawdown Notice. Unless the Agent has been notified by a Lender prior to noon (Toronto time) on the date of the extension of credit that such Lender will not make available to the Agent its Pro Rata Share of such Prime Rate Loan, the Agent may assume that such Lender has made such portion of the Prime Rate Loan available to the Agent on the date of the extension of credit in accordance with the provisions hereof and the Agent may, in reliance upon such assumption, make available to the relevant Borrower on such date a corresponding amount. If the Agent has made such assumption, to the extent such Lender shall not have so made its Pro Rata Share of the Prime Rate Loan available to the Agent, such Lender agrees to pay to the Agent, forthwith on demand, such Lender's Pro Rata Share of the Prime Rate Loan and all reasonable costs and expenses incurred by the Agent in connection therewith together with interest thereon at the then prevailing interbank rate for each day from the date such amount is made available to the relevant Borrower until the date such amount is paid or repaid to the Agent; provided, however, that notwithstanding such obligation, if such Lender fails so to pay, the relevant Borrower shall, without prejudice to any rights that such Borrower might have against such Lender, repay such amount to the Agent forthwith after demand therefor by the Agent. The amount payable by such Lender to the Agent pursuant hereto shall be set forth in a certificate delivered by the Agent to such Lender and the relevant Borrower (which certificate shall contain reasonable details of how the amount payable is calculated) and shall constitute *prima facie* evidence of such amount payable. If such Lender makes the payment to the Agent required herein, the amount so paid shall constitute such Lender's Pro Rata Share of the Prime Rate Loan for purposes of this Agreement and shall entitle such Lender to all rights and remedies against the relevant Borrower in respect of such Loan.

3.3 Failure of Lender to Fund Prime Rate Loan. If any Lender fails to make available to the Agent its Pro Rata Share of any Prime Rate Loan under the Credit Facility as required under Section 3.2 (such Lender being herein called the "**Defaulting Lender**") and the Agent has not funded pursuant to Section 3.2, the Agent shall forthwith give notice of such failure by the Defaulting Lender to the relevant Borrower and the other Lenders and such notice shall state that any Lender may make available to the Agent all or any portion of the Defaulting Lender's Pro Rata Share of such Prime Rate Loan (but in no way shall any other Lender or the Agent be obliged to do so) in the place and stead of the Defaulting Lender. If more than one Lender gives notice that it is prepared to make funds available in the place and stead of a Defaulting Lender in such circumstances and the aggregate of the funds which such Lenders

(herein collectively called the "**Contributing Lenders**" and individually called the "**Contributing Lender**") are prepared to make available exceeds the amount of the advance which the Defaulting Lender failed to make, then each Contributing Lender shall be deemed to have given notice that it is prepared to make available its *pro rata* share of such advance based on the Contributing Lenders' relative commitments to advance in such circumstances. If any Contributing Lender makes funds available in the place and stead of a Defaulting Lender in such circumstances, then the Defaulting Lender shall pay to any Contributing Lender making the funds available in its place and stead, forthwith on demand, any amount advanced on its behalf together with interest thereon at the then prevailing interbank rate for each day from the date of advance to the date of payment, against payment by the Contributing Lender making the funds available of all interest received in respect of the Prime Rate Loan from any Borrower. In addition to interest as aforesaid, each Borrower shall pay all amounts owing by it to the Defaulting Lender hereunder (with respect to the amounts advanced by the Contributing Lenders on behalf of the Defaulting Lender) to the Contributing Lenders in accordance with Section 3.7 until such time as the Defaulting Lender pays to the Agent for the Contributing Lenders all amounts advanced by the Contributing Lenders on behalf of the Defaulting Lender.

3.4 Funding of Bankers' Acceptances

(a) If the Agent receives a Drawdown Notice, Rollover Notice or Conversion Notice requesting a drawdown of, a rollover of or a conversion into Bankers' Acceptances, the Agent shall notify each of the Lenders, prior to noon (Toronto time) on the first Business Day prior to the date of such extension of credit of such request of each Lender's Pro Rata Share of such extension of credit. The Agent shall also at such time notify the relevant Borrower of each Lender's Pro Rata Share of such extension of credit.

(b) If, by noon (Toronto time) on the first Business Day prior to the date of extension of credit, the relevant Borrower has not advised the Agent in writing that it will be arranging its own sale of the Bankers' Acceptances, each Lender shall purchase each Bankers' Acceptance accepted by it (forthwith after the acceptance thereof) as herein provided. If, by the aforesaid time, the relevant Borrower does advise the Agent in writing that it will be arranging its own sale of the Bankers' Acceptances, such Borrower shall, not later than 11:00 a.m. (Toronto time) on the date of the extension of credit, irrevocably notify the Agent of the name of the purchaser or purchasers of the Bankers' Acceptances accepted by each Lender, the purchase price therefor and the denominations thereof and the Agent shall forthwith notify each Lender accordingly.

(c) Subject to Section 3.5, each Lender shall, not later than noon (Toronto time) on the date of each extension of credit by way of Bankers' Acceptance, accept drafts of the relevant Borrower which are presented to it for acceptance and which have an aggregate face amount equal to such Lender's Pro Rata Share of the total extension of credit being made available by way of Bankers' Acceptances on such date, as advised by the Agent. Subject to the provisions hereof, the Agent shall be responsible for making all necessary arrangements with each of the Lenders with respect to the stamping of Bankers' Acceptances.

(d) Each Lender may at any time and from time to time hold, sell, rediscount or otherwise dispose of any or all Bankers' Acceptances accepted and purchased by it. With respect to Bankers' Acceptances which are not purchased by the accepting Lenders, the accepting Lenders shall deliver the Bankers' Acceptances accepted by them to the purchasers thereof against receipt of the purchase price therefor as advised by the Agent.

(e) The relevant Borrower shall provide for payment to the accepting Lenders of the face amount of each Bankers' Acceptance at its maturity, either by payment of such amount or through an extension of credit hereunder or through a combination of both. Each Borrower hereby waives presentment for payment of Bankers' Acceptances by the Lenders and any defence to payment of amounts due to a Lender in respect of a Bankers' Acceptance which might exist by reason of such Bankers' Acceptance being held at maturity by the Lender which accepted it and agrees not to claim from such Lender any days of grace for the payment at maturity of Bankers' Acceptances. In the event that any Borrower fails to deliver a Conversion Notice or Rollover Notice and fails to make payment to the Agent in respect of the maturing Bankers' Acceptances, the face amount of the maturing Bankers' Acceptances shall be deemed to be converted to a Prime Rate Loan on the relevant maturity date pursuant to Section 6.4.

(f) In the case of a drawdown by way of Bankers' Acceptance, each Lender shall, forthwith after the acceptance of drafts of the relevant Borrower as aforesaid, make available to the Agent the BA Net Proceeds with respect to the Bankers' Acceptances accepted by it. The Agent shall, upon fulfilment by the relevant Borrower of the terms and conditions set forth in Article 12, make such BA Net Proceeds available to the relevant Borrower on the date of such extension of credit by crediting the appropriate Designated Account.

(g) In the case of a rollover of or conversion into Bankers' Acceptances:

(i) if the relevant Borrower has elected that the Lenders shall purchase the Bankers' Acceptances accepted by them, each Lender shall retain the Bankers' Acceptance accepted by it and shall not be required to make any funds available to the Agent for deposit to the appropriate Designated Account; however, forthwith after the acceptance of drafts of such Borrower as aforesaid, such Borrower shall pay to the Agent on behalf of the Lenders an amount equal to the aggregate amount of the acceptance fees in respect of such Bankers' Acceptances calculated in accordance with Section 7.4 plus the amount by which the aggregate face amount of such Bankers' Acceptances exceeds the aggregate BA Discounted Proceeds with respect thereto; or

(ii) if the relevant Borrower has elected that the Lenders shall not purchase the Bankers' Acceptances accepted by them, each Lender shall retain the purchase price paid for the Bankers' Acceptances which it has accepted and it shall not be required to make any funds available to the Agent for

deposit to the appropriate Designated Account; however, forthwith after the acceptance of drafts of such Borrower as aforesaid, such Borrower shall pay to the Agent on behalf of the Lenders an amount equal to the aggregate amount of the acceptance fees in respect of such Bankers' Acceptances calculated in accordance with Section 7.4 plus the amount by which the aggregate face amount of such Bankers' Acceptances exceeds the aggregate purchase price for such Bankers' Acceptances.

(h) Any Bankers' Acceptance may, at the option of the relevant Borrower, be executed in advance by such Borrower by mechanically reproduced or facsimile signatures of any two officers of such Borrower who are properly so designated and authorized by such Borrower from time to time. Any Bankers' Acceptance so executed and delivered by the relevant Borrower to the Lenders shall be valid and shall bind such Borrower and may be dealt with by the Lenders to all intents and purposes as if the Bankers' Acceptance had been signed in the executing officers' own handwriting.

(i) The relevant Borrower shall notify the Lenders as to those officers whose signatures may be reproduced and used to execute Bankers' Acceptances in the manner provided in Section 3.4(h). Bankers' Acceptances with the mechanically reproduced or facsimile signatures of designated officers may be used by the Lenders and shall continue to be valid, notwithstanding the death, termination of employment or termination of authorization of either or both of such officers or any other circumstance.

(j) Each Borrower hereby indemnifies and agrees to hold harmless the Lenders against and from all losses, damages, expenses and other liabilities caused by or attributable to the use of the mechanically reproduced or facsimile signature instead of the original signature of an authorized officer of such Borrower on a Bankers' Acceptance prepared, executed, issued and accepted pursuant to this Agreement, except to the extent determined by a court of competent jurisdiction to be due to the gross negligence or wilful misconduct of the relevant Lender.

(k) Each of the Lenders agrees that, in respect of the safekeeping of executed drafts of the relevant Borrower which are delivered to it for acceptance hereunder, it shall exercise relevant the same degree of care which it gives to its own property, provided that it shall not be deemed to be an insurer thereof.

(l) All Bankers' Acceptances to be accepted by a particular Lender shall, at the option of such Lender, be issued in the form of depository bills made payable originally to and deposited with CDS Clearing and Depository Services Inc. pursuant to the *Depository Bills and Notes Act* (Canada).

(m) In order to facilitate the issuance of Bankers' Acceptances pursuant to this Agreement, each Borrower hereby authorizes each of the Lenders, and appoints each of the Lenders as such Borrower's attorney, to complete, sign and endorse drafts or depository bills (as defined in the *Depository Bills and Notes Act*

(Canada)) on its behalf in handwritten form or by facsimile or mechanical signature or otherwise in accordance with the applicable Drawdown Notice, Conversion Notice or Rollover Notice and, once so completed, signed and endorsed to accept them as Bankers' Acceptances under this Agreement and then if applicable, purchase, discount or negotiate such Bankers' Acceptances in accordance with the provisions of this Agreement. Drafts or depository bills so completed, signed, endorsed and negotiated on behalf of a Borrower by a Lender shall bind such Borrower as fully and effectively as if so performed by an authorized officer of such Borrower. Each draft of a Bankers' Acceptance and each depository bill completed, signed or endorsed by a Lender shall mature on the last day of the term thereof.

3.5 BA Rate Loans. If, in the sole judgment of a Lender, such Lender is unable to extend credit by way of Bankers' Acceptances in accordance with this Agreement, such Lender shall give an irrevocable notice to such effect to the Agent and the relevant Borrower prior to 11:00 a.m. (Toronto time) on the date of the requested credit extension and shall make available to the relevant Borrower prior to noon (Toronto time) on the date of such requested credit extension a Canadian dollar loan (a "**BA Rate Loan**") in the principal amount equal to such Lender's Pro Rata Share of the total credit to be extended by way of Bankers' Acceptances, such BA Rate Loan to be funded in the same manner as a Prime Rate Loan is funded pursuant to Sections 3.2 and 3.3. Such BA Rate Loan shall have the same term as the Bankers' Acceptances for which it is a substitute and shall bear such rate of interest per annum throughout the term thereof as shall permit such Lender to obtain the same effective rate as if such Lender had accepted and purchased a Bankers' Acceptance at the same acceptance fee and pricing at which the Agent would have accepted and purchased, on the bid side of the market, such Bankers' Acceptance at approximately 1:00 p.m. (Toronto time) on the date such BA Rate Loan is made, on the basis that, and the relevant Borrower hereby agrees that, for such a BA Rate Loan, interest shall be payable in advance on the date of the extension of credit by the Lender deducting the interest payable in respect thereof from the principal amount of such BA Rate Loan. All terms of this Agreement applicable to Bankers' Acceptances shall apply equally to BA Rate Loans with such changes as the Agent may in the context deem to be necessary.

3.6 Timing of Credit Availments. No Bankers' Acceptance or BA Rate Loan under the Credit Facility may have a maturity date later than the Maturity Date.

3.7 Time and Place of Payments. Unless otherwise expressly provided herein, each Borrower shall make all payments pursuant to this Agreement or pursuant to any document, instrument or agreement delivered pursuant hereto by deposit to the appropriate Designated Account before 1:00 p.m. (Toronto time) on the day specified for payment and the Agent shall be entitled to withdraw the amount of any payment due to the Agent, the Lenders or any of them from such account on the day specified for payment. Any such payment received on the day specified for such payment but after 1:00 p.m. (Toronto time) thereon shall be deemed to have been received prior to 1:00 p.m. (Toronto time) on the Business Day immediately following such day specified for payment.

3.8 Remittance of Payments. Forthwith after the withdrawal from the appropriate Designated Account by the Agent of any payment of principal, interest, fees or other amounts for

the benefit of all of the Lenders pursuant to Section 3.7, the Agent shall, subject to Sections 3.3 and 8.3, remit to each Lender, in immediately available funds, such Lender's Pro Rata Share of such payment; provided that if the Agent, on the assumption that it will receive, on any particular date, a payment of principal (including, without limitation, a prepayment), interest, fees or other amount hereunder, remits to each Lender its Pro Rata Share of such payment and any Borrower fails to make such payment, each of the Lenders agrees to repay to the Agent, forthwith on demand, to the extent that such amount is not recovered from such Borrower on demand and after reasonable efforts by the Agent to collect such amount (without in any way obligating the Agent to take any legal action with respect to such collection), such Lender's Pro Rata Share of the payment made to it pursuant hereto together with interest thereon at the then prevailing interbank rate for each day from the date such amount is remitted to the Lenders until the date such amount is paid or repaid to the Agent, the exact amount of the repayment required to be made by the Lenders pursuant hereto to be as set forth in a certificate delivered by the Agent to each Lender, which certificate shall constitute *prima facie* evidence of such amount of repayment.

3.9 Evidence of Indebtedness. The Agent shall open and maintain accounts wherein the Agent shall record the amount of credit outstanding, each advance and each payment of principal and interest on account of each Loan, each Bankers' Acceptance accepted, purchased and cancelled, each Letter issued and drawn upon and all other amounts becoming due to and being paid to the Agent or the Lenders hereunder and under any of the other Loan Documents. The Agent's accounts constitute, in the absence of manifest error, *prima facie* evidence of the indebtedness of the Borrowers to the Agent and the Lenders hereunder and under the other Loan Documents.

3.10 General Provisions Relating to Letters.

(a) Each Borrower hereby acknowledges and confirms to the Fronting Lender that the Fronting Lender shall not be obliged to make any inquiry or investigation as to the right of any beneficiary to make any claim or draft or request any payment under a Letter and payment by the Fronting Lender pursuant to a Letter shall not be withheld by the Fronting Lender by reason of any matters in dispute between the beneficiary thereof and the relevant Borrower. The sole obligation of the Fronting Lender with respect to Letters is to cause to be paid a draft drawn or purporting to be drawn in accordance with the terms of the applicable Letter and for such purpose the Fronting Lender is only obliged to determine that the draft purports to comply with the terms and conditions of the relevant Letter.

(b) The Fronting Lender shall not have any responsibility or liability for or any duty to inquire into the form, sufficiency (other than to the extent provided in the preceding paragraph), authorization, execution, signature, endorsement, correctness (other than to the extent provided in the preceding paragraph), genuineness or legal effect of any draft, certificate or other document presented to it pursuant to a Letter and the relevant Borrower unconditionally assumes all risks with respect to the same. Each Borrower agrees that it assumes all risks of the acts or omissions of the beneficiary of any Letter with respect to the use by such beneficiary of the relevant Letter.

(c) **Indemnity**. Each Borrower shall indemnify and save harmless the Lenders, the Agent and the Fronting Lender (except to the extent caused by the gross negligence or wilful misconduct of any of the Lenders, the Agent or the Fronting Lender) against all claims, losses, costs, expenses or damages to the Lenders, the Agent and the Fronting Lender arising out of or in connection with any Letter, the issuance thereof, any payment thereunder or any action taken by the Lenders, the Agent and the Fronting Lender or any other Person in connection therewith, including, without limitation, all costs relating to any legal process or proceeding instituted by any party restraining or seeking to restrain the Agent or the Fronting Lender from accepting or paying any Draft or any amount under any such Letter.

(d) The obligations of the Borrower hereunder with respect to Letters shall be absolute, unconditional and irrevocable and shall not be reduced by any event or occurrence including, without limitation:

(i) any lack of validity or enforceability of this Agreement or any such Letter;

(ii) any amendment or waiver of or any consent to departure from this Agreement;

(iii) the existence of any claim, set-off, defence or other rights which such Borrower may have at any time against any beneficiary or any transferee of any such Letter (or any Person or entities for whom any such beneficiary or any such transferee may be acting), any Lender, the Fronting Lender or any other Person;

(iv) any Draft, statement or other document presented under any such Letter proving to be forged, fraudulent, invalid or insufficient in any respect or any statement therein being untrue or inaccurate in any respect whatsoever;

(v) payment by the Fronting Lender under such Letter against presentation of a sight draft or certificate which does not comply with the terms of such Letter;

(vi) any non-application or misapplication by the beneficiary of such Letter of the proceeds of any drawing under such Letter; or

(vii) any reduction or withdrawal of the Fronting Lender's credit rating by any rating agency.

The obligations of the relevant Borrower hereunder with respect to Letters shall remain in full force and effect and shall apply to any amendment to or extension of the expiration date of any such Letter.

(e) Any action, inaction or omission taken or suffered by the Fronting Lender or any of the Fronting Lender's correspondents under or in connection with a Letter or any Draft made thereunder, if in good faith and in conformity with foreign or

domestic laws, regulations or customs applicable thereto, shall be binding upon the relevant Borrower and shall not place the Fronting Lender or any of its correspondents under any resulting liability to such Borrower. Without limiting the generality of the foregoing, the Fronting Lender and its correspondents may receive, accept or pay as complying with the terms of a Letter, any draft thereunder, otherwise in order which may be signed by, or issued to, the administrator or any executor of, or the trustee in bankruptcy of, or the receiver for any property of, or other Person or entity acting as the representative or in the place of, such beneficiary or its successors and assigns. Each Borrower covenants that it will not take any steps, issue any instructions to the Fronting Lender or any of its correspondents or institute any proceedings intended to derogate from the right or ability of the Fronting Lender or its correspondents to honour and pay any draft or drafts.

(f) Each Borrower agrees that the Lenders, the Fronting Lender and the Agent shall have no liability to it for any reason in respect of or in connection with any Letter, the issuance thereof, any payment thereunder, or any other action taken by the Lenders, the Fronting Lender or the Agent or any other Person in connection therewith, other than on account of the Fronting Lender's gross negligence or wilful misconduct.

(g) Save to the extent expressly provided otherwise in this Section 3.10, the rights and obligations between the Fronting Lender and each Company with respect to each Letter shall be determined in accordance with the applicable provisions of the (i) Uniform Customs and Practice for Documentary Credits (2006 Revision), ICC Publications 600 or (ii) the International Standby Practices - ISP98, ICC Publication No. 590, as applicable.

3.11 Notice Periods. Each Drawdown Notice, Rollover Notice and Conversion Notice shall be given to the Agent:

(a) prior to 9:00 a.m. (Toronto time) on the second Business Day prior to the date of a drawdown of a Letter;

(b) prior to 10:00 a.m. (Toronto time) on the first Business Day prior to the date of a drawdown of, rollover of, conversion of or conversion into a Bankers' Acceptance or BA Rate Loan; and

(c) prior to 10:00 a.m. (Toronto time) on the date of any other drawdown, rollover or conversion.

ARTICLE 4
DRAWDOWN

4.1 Drawdown. Subject to the terms and conditions hereof and provided that all of the applicable conditions precedent set forth in Article 12 have been fulfilled by the Borrowers or waived by the Agent, each Borrower may obtain credit under the Credit Facility from time to time by way of drawdown by giving to the Agent an irrevocable notice (the "**Drawdown**

Notice") in accordance with Section 3.10, in substantially the form of Schedule D hereto, which notice shall specify:

(a) the date of the drawdown;

(b) whether the credit is to be extended by way of Prime Rate Loan, Bankers' Acceptance or a Letter or a combination thereof;

(c) to the extent credit is to be extended by way of Prime Rate Loan, the principal amount thereof;

(d) to the extent credit is to be extended by way of Bankers' Acceptances, the aggregate face amount of the Bankers' Acceptances to be issued and the term of the Bankers' Acceptances to be issued;

(e) if the credit is to be obtained by way of Letter, the type of Letter, the date of issuance of the Letter, the named beneficiary of the Letter, the maturity date and amount of the Letter, the currency of denomination of the Letter and all other terms of the Letter; and

(f) the details of any irrevocable authorization and direction pursuant to Section 3.2.

ARTICLE 5
ROLLOVERS

5.1 Bankers' Acceptances. Subject to Section 3.5 and provided that a Borrower has, by giving notice to the Agent in accordance with Section 5.2 requested the Lenders to accept its drafts or accept and purchase its drafts, as the case may be, to replace all or a portion of outstanding Bankers' Acceptances as they mature, each Lender shall, on the maturity of such Bankers' Acceptances, accept or accept and purchase, as the case may be, such Borrower's draft or drafts having an aggregate face amount equal to its Pro Rata Share of the aggregate face amount of the matured Bankers' Acceptances or the portion thereof to be replaced in accordance with Section 3.4.

5.2 Rollover Notice. The notice to be given to the Agent pursuant to Section 5.1 (the "**Rollover Notice**") shall be irrevocable, shall be given in accordance with Section 3.10 and be in substantially the form of Schedule E hereto and shall specify:

(a) the maturity date of the maturing Bankers' Acceptances;

(b) the face amount of the maturing Bankers' Acceptances and the portion thereof to be replaced; and

(c) the number of new Bankers' Acceptances to be issued, the face amount of each new Bankers' Acceptance and the term of each new Bankers' Acceptance.

ARTICLE 6
CONVERSIONS

6.1 Converting Prime Rate Loans to Bankers' Acceptances. Subject to Section 3.5 and provided that a Borrower has, by giving notice to the Agent in accordance with Section 6.3, requested the Lenders to accept its drafts or accept and purchase its drafts, as the case may be, to replace all or a portion of an outstanding Prime Rate Loan and provided further that no Default has occurred and is continuing, each Lender shall, on the date of conversion, accept or accept and purchase, as the case may be, such Borrower's draft or drafts having an aggregate face amount equal to its Pro Rata Share of the aggregate principal amount of such Loan or the portion thereof which is being converted, such acceptance or acceptance and purchase, as the case may be, to be in accordance with Section 3.4.

6.2 Converting Bankers' Acceptances and BA Rate Loans to Prime Rate Loans. Each Lender shall, on the maturity date of a Bankers' Acceptance which such Lender has accepted, pay to the holder thereof the face amount of such Bankers' Acceptance. Provided that a Borrower has, by giving notice to the Agent in accordance with Section 6.3, requested the Lenders to convert all or a portion of outstanding maturing Bankers' Acceptances into a Prime Rate Loan or, in accordance with Section 6.4 or 6.5 there is a deemed conversion into a Prime Rate Loan, upon the maturity date of such Bankers' Acceptance, each Lender shall, upon the payment by such Lender to the holders of such maturing Bankers' Acceptances of the aggregate face amount thereof, extend credit to such Borrower by way of the requested Prime Rate Loan in the principal amount equal to its Pro Rata Share of the aggregate amount of credit represented by such maturing Bankers' Acceptances or the portion thereof which is being converted. Where a particular Lender has funded a Borrower by way of a BA Rate Loan rather than by way of Bankers' Acceptances, the provisions of this Section 6.2 as they relate to Bankers' Acceptances shall apply *mutatis mutandis* to such BA Rate Loan.

6.3 Conversion Notice. The notice to be given to the Agent pursuant to Section 6.1 or 6.2 (the "**Conversion Notice**") shall be irrevocable, shall be given in accordance with Section 3.10 and be in substantially the form of Schedule F hereto and shall specify:

(a) whether an outstanding Prime Rate Loan or Bankers' Acceptances are to be converted;

(b) the date on which the conversion is to take place;

(c) the face amount of the Bankers' Acceptances or the portion thereof which is to be converted or the principal amount of the Prime Rate Loan or the portion thereof which is to be converted;

(d) the amount of the Prime Rate Loan into which the outstanding Bankers' Acceptances are to be converted; and

(e) if an outstanding Prime Rate Loan is to be converted into Bankers' Acceptances, the number of new Bankers' Acceptances to be issued, the aggregate face amount of the new Bankers' Acceptances to be issued and the term or terms of the new Bankers' Acceptances.

6.4 Absence of Notice. In the absence of a Rollover Notice or Conversion Notice within the appropriate time periods referred to herein, a maturing Bankers' Acceptance or BA Rate Loan shall be automatically converted to a Prime Rate Loan as though a notice to such effect had been given in accordance with Section 6.3.

6.5 Conversion after Default. If a Default has occurred and is continuing at 11:00 a.m. (Toronto time) on the first Business Day prior to the maturity of a Bankers' Acceptance or BA Rate Loan, such Bankers' Acceptance or BA Rate Loan shall automatically convert into a Prime Rate Loan as though a notice to such effect had been given in accordance with Section 6.3.

ARTICLE 7
INTEREST RATES AND FEES

7.1 Interest Rates. Each of the Borrowers shall pay to the Lenders, in accordance with Section 3.7, interest on the outstanding principal amount from time to time of each Prime Rate Loan made to such Borrower under the Credit Facility from time to time at the rate per annum equal to the Prime Rate plus the Applicable Margin.

7.2 Calculation and Payment of Interest

(a) Interest on the outstanding principal amount from time to time of each Prime Rate Loan and on the amount of overdue interest outstanding thereon from time to time shall accrue from day to day from and including the date on which the credit is obtained by way of such Loan or the date on which such payment of overdue interest was due, as the case may be, to but excluding the date on which such Loan or such overdue interest, as the case may be, is repaid in full (both before and after maturity and as well after as before judgment) and shall be calculated on the basis of the actual number of days elapsed divided by 365 or 366, as the case may be.

(b) Accrued interest shall be paid, in the case of interest on Prime Rate Loans, in arrears on the last Business Day of each calendar month.

(c) Interest on each BA Rate Loan shall be paid in advance as provided in Section 3.5.

7.3 General Interest Rules. If a Borrower fails to pay any principal, interest, interest equivalent, fee or other material amount of any nature payable by it hereunder on the due date therefor, such Borrower shall pay to the Lenders interest on such overdue amount in the same currency as such overdue amount is payable from and including such due date to but excluding the date of actual payment (as well after as before judgment) at the rate per annum, calculated and compounded monthly, which is equal to the Prime Rate plus 2% per annum. Such interest on overdue amounts shall become due and be paid on demand by the Agent.

7.4 Acceptance Fees. Upon the acceptance of any draft of a Borrower pursuant hereto, such Borrower shall pay to the Lenders in advance, in the manner provided in Sections 3.4(f) and (g) and 3.7, an acceptance fee calculated at the rate per annum, on the basis

of a year of 365 days, equal to the Applicable Margin on the face amount of such Bankers' Acceptance for its term, the term of such Bankers' Acceptance being the actual number of days in the period commencing on the date of acceptance of such Borrower's draft and ending on but excluding the maturity date of the Bankers' Acceptance. With respect to each drawdown by way of Bankers' Acceptances, such acceptance fees shall be paid by the Lenders deducting the amount thereof from the BA Gross Proceeds received by the Lenders before the Lenders remit the BA Net Proceeds to the Agent as provided in Section 3.4(f). With respect to each rollover of and conversion into Bankers' Acceptances, such acceptance fees shall be paid by such Borrower to the Agent as provided in Section 3.4(g). Each such payment is non-refundable and fully earned when due.

7.5 Standby Fees. Upon the first Business Day of each Fiscal Quarter commencing after the Closing Date and on the Maturity Date, each of the Borrowers shall pay to the Lenders, in arrears, a standby fee, calculated and accruing daily from and including the Closing Date at the rate per annum, calculated on the basis of a year of 365 days or, in the case of a leap year, 366 days, equal to one-third of 0.25% on the amount of the Available Credit.

7.6 Letter Fees. Each of the Borrowers shall pay to the Lenders, in accordance with Section 3.8, an issuance fee quarterly in arrears on the first Business Day of each Fiscal Quarter, calculated at a rate per annum, on the basis of a year of 365 days or 366 days in the case of a leap year, equal to the Applicable Margin and on the amount of each Letter issued on the credit of such Borrower for the number of days in the preceding Fiscal Quarter on which such Letter was outstanding. In addition, each of the Borrowers shall from time to time pay to the Lenders their usual and customary fees (at the then prevailing rates) (other than issuance or fronting fees, each of which is otherwise dealt with herein) for the amendment, delivery and administration of letters of credit such as the Letters.

ARTICLE 8
CAPITAL, INDEMNITY AND TAX PROVISIONS

8.1 Conditions of Credit. The obtaining or maintaining of credit hereunder shall be subject to the terms and conditions contained in this Article 8.

8.2 Change of Circumstances

(a) If, after the date hereof, the introduction of or any change in or in the interpretation of, or any change in its application to any Lender (the "**Affected Party**"), any Law of any Governmental Authority (whether or not having the force of Law but, if not having the force of Law, one with which a responsible Canadian chartered bank would comply), including, without limitation, any reserve or special deposit requirement or any tax (other than tax on an Affected Party's income) or any capital requirement, has, due to an Affected Party's compliance, the effect, directly or indirectly, of (i) increasing the cost to such Affected Party of performing its obligations hereunder or under any Bankers' Acceptance; (ii) reducing any amount received or receivable by such Affected Party hereunder or its effective return hereunder or under any Bankers' Acceptance or on its capital; or (iii) causing such Affected Party to make any

payment or to forego any return based on any amount received or receivable hereunder or under any Bankers' Acceptance by such Affected Party, then, upon demand (which demand shall be accompanied by a certificate setting out the reason for and the calculation of the relevant amount) from time to time each of the Borrowers shall pay such amount as shall compensate such Affected Party for any such cost, reduction, payment or foregone return accruing to the date of the aforesaid demand from a date not exceeding 60 days prior to such date of demand (the "**Additional Compensation**") and based on the aggregate amount of Loans, Bankers' Acceptances and Letters outstanding to such Borrower during such period; provided that the Borrowers shall be obligated under this Section 8.2(a) to compensate such Affected Party for any increase in such Affected Party's capital adequacy requirements measured against its outstanding obligations hereunder only to the extent such capital adequacy requirements are in excess of the capital adequacy requirements as of the date hereof. Any certificate of an Affected Party in respect of the foregoing will be conclusive and binding upon the Borrowers, except for manifest error, provided that such Affected Party shall determine the Additional Compensation owing to it in good faith using any reasonable averaging and attribution methods.

(b) Each Affected Party agrees that, as promptly as practicable after it becomes aware of the occurrence of an event or the existence of a condition that would cause it to seek Additional Compensation from the Borrowers pursuant to Section 8.2(a), it will use reasonable efforts to make, fund or maintain the affected credit through another lending office or take such other actions as it deems appropriate if as a result thereof the Additional Compensation which would otherwise be required to be paid in respect of such credit pursuant to Section 8.2(a), would be reduced and if, as determined by such Affected Party in its sole discretion, the making, funding or maintaining of such credit through such other lending office or the taking of such other actions would not otherwise adversely affect such credit or such Affected Party and would not, in such Affected Party's sole discretion, be commercially unreasonable. Each Affected Party further agrees that if such Affected Party subsequently recovers all or part of the Additional Compensation paid by the Borrowers, it shall repay an equal amount to the Borrowers. The Borrowers shall be entitled to prepay any outstanding credit hereunder (provided that Bankers' Acceptances and BA Rate Loans may only be prepaid on their maturity) which is the subject of a demand for Additional Compensation under this Section 8.2 without notice, bonus or penalty. Additional Compensation shall only be payable by the Borrowers pursuant to this Section 8.2 if similar compensation is being claimed as a general practice from customers of such Affected Party who by agreement are liable to pay similar compensation.

(c) Notwithstanding the foregoing provisions, a Lender shall only be entitled to rely upon the provisions of this Section 8.2 if and for so long as it is not treating the Borrowers in any materially different or in any materially less favourable manner than is applicable to any other customers of the relevant Lender, where such other customers are bound by similar provisions to the foregoing provisions of this Section 8.2.

8.3 Failure of Lenders to Fund as a Result of Change of Circumstances. If any Lender but not all of the Lenders seeks Additional Compensation pursuant to Section 8.2(a) (in each case, the "**Affected Lender**"), then the Borrowers may indicate to the Agent in writing that they desire to replace the Affected Lender with one or more of the other Lenders, and the Agent shall then forthwith give notice to the other Lenders that any Lender or Lenders may, in the aggregate, assume all (but not part) of the Affected Lender's Individual Commitment and obligations hereunder and, in the aggregate, acquire all (but not part) of the rights of the Affected Lender hereunder and assume all (but not part) of the obligations of the Affected Lender under each of the other Loan Documents (but in no event shall any other Lender or the Agent be obliged to do so). If one or more Lenders shall so agree in writing (herein collectively called the "**Assenting Lenders**" and individually called an "**Assenting Lender**") with respect to such acquisition and assumption, the Individual Commitment and the obligations of such Assenting Lender under this Agreement and the rights and obligations of such Assenting Lender under each of the other Loan Documents shall be increased by its respective *pro rata* share (based on the relative Individual Commitments of the Assenting Lenders) of the Affected Lender's Pro Rata Share of such credit and Individual Commitment and obligations under this Agreement and rights and obligations under each of the other Loan Documents on a date mutually acceptable to the Assenting Lenders and the Borrowers. On such date, the Assenting Lenders shall pay to the Affected Lender the advances of the Affected Lender then outstanding, together with all interest accrued thereon and all other amounts owing to the Affected Lender hereunder, and, upon such payment by the Assenting Lenders, the Affected Lender shall cease to be a "**Lender**" for purposes of this Agreement and shall no longer have any obligations hereunder. Upon the assumption of the Affected Lender's Individual Commitment or portion thereof as aforesaid by an Assenting Lender, Schedule A hereto shall be deemed to be amended to increase the Individual Commitment of such Assenting Lender by the respective amounts of such assumption. If all of the Affected Lender's rights and obligations under the Loan Documents have not been acquired and assumed by Assenting Lenders, the Borrowers may locate other financial institutions ("**Substitute Lenders**") who are satisfactory to the Agent, acting reasonably, and who acquire and assume all of the balance of the rights and obligations of the Affected Lender under the Loan Documents on a date mutually acceptable to the Borrowers and the Substitute Lenders, any such assignment and assumption to be effected in accordance with the procedures set out in Section 16.6(c). If all of the Affected Lender's rights and obligations under the Loan Documents have not been acquired and assumed by Assenting Lenders and Substitute Lenders, then provided there does not then exist any Default and no Event of Default has occurred and not been remedied or waived, each Borrower may, at its election, repay all outstanding amounts due from such Borrower to such Affected Lender (or such portion which has not been acquired by Assenting Lenders and Substitute Lenders, as the case may be) and thereupon the Individual Commitment of the Affected Lender shall be permanently cancelled and the aggregate amount of Individual Commitments shall be permanently reduced by the same amount and the Individual Commitment of each of the other Lenders shall remain the same.

8.4 Indemnity Relating to Credits. Upon notice from the Agent or a Lender (which notice shall be accompanied by a detailed calculation of the amount to be paid by the relevant Borrower), such Borrower shall pay to such Lender such amount or amounts as will compensate the Agent or such Lender for any loss, cost or expense incurred by it:

(a) in the liquidation or redeposit of any funds acquired by the Lender to fund or maintain any portion of a Loan as a result of:

(i) the failure of such Borrower to borrow or make repayments on the dates specified under this Agreement or in any notice from such Borrower to the Agent; or

(ii) the repayment or prepayment by such Borrower of any amounts on a day other than the payment dates prescribed herein; or

(b) with respect to any Bankers' Acceptance or Letter, arising from claims or legal proceedings, and including reasonable legal fees and disbursements, respecting the obtaining of credit by such Borrower by way of such Bankers' Acceptance or Letter, the collection of amounts owed by such Borrower hereunder in respect of such Bankers' Acceptance or Letter or the enforcement of the Agent's or any Lender's rights hereunder in respect of such Bankers' Acceptance or Letter including, without limitation, legal proceedings attempting to restrain the Agent or any Lender from paying any amount under such Bankers' Acceptance or Letter.

8.5 Indemnity for Transactional and Environmental Liability

(a) Each Borrower hereby agrees to indemnify, exonerate and hold the Agent, each Lender and each of their respective shareholders, officers, directors, employees and agents (collectively, the "**Indemnified Parties**") free and harmless from and against any and all claims, demands, actions, causes of action, suits, losses, costs (including, without limitation, all documentary, recording, filing, mortgage or other stamp taxes or duties), charges, liabilities and damages, and reasonable expenses in connection therewith (irrespective of whether such Indemnified Party is a party to the action for which indemnification hereunder is sought), and including, without limitation, reasonable legal fees and reasonable out-of-pocket disbursements and amounts paid in settlement of any and every kind whatsoever (collectively, in this Section 8.5(a), the "**Indemnified Liabilities**"), paid, incurred or suffered by, or asserted against, the Indemnified Parties or any of them as a result of, or arising out of, or relating to (i) the extension of credit to such Borrower contemplated herein, (ii) any transaction financed or to be financed in whole or in part, directly or indirectly, with the proceeds of any credit extended to such Borrower hereunder, (iii) any actual or threatened investigation, litigation or other proceeding relating to any credit extended to such Borrower or proposed to be extended to such Borrower as contemplated herein or (iv) the execution, delivery, performance or enforcement of any Loan Document and any instrument, document or agreement executed pursuant hereto or thereto, except for any such Indemnified Liabilities (x) that a court of competent jurisdiction determines in a final non-appealable decision arose on account of the relevant Indemnified Party's gross negligence or wilful misconduct or (y) that constitute loss of profit, loss of income or revenue or loss of business opportunity of such Indemnified Party.

(b) Without limiting the generality of the indemnity set out in Section 8.5(a), each Borrower hereby further agrees to indemnify, exonerate and hold the Indemnified Parties free and harmless from and against any and all claims, demands, actions, causes of action, suits, losses, costs, charges, liabilities and damages, and reasonable expenses in connection therewith, including, without limitation, reasonable legal fees and reasonable out-of-pocket disbursements, and amounts paid in settlement, of any and every kind whatsoever (collectively, in this Section 8.5(b), the "**Indemnified Liabilities**"), paid, incurred or suffered by, or asserted against the Indemnified Parties or any of them for, with respect to, or as a direct or indirect result of, (i) the presence on or under, or the escape, seepage, leakage, spillage, discharge, emission or release from, any real property legally or beneficially owned (or any estate or interest which is owned), leased, occupied or operated by such Borrower of any Hazardous Material or (ii) the breach or violation of any Environmental Law by such Borrower, regardless of whether caused by, or within the control of, such Borrower, except for any such Indemnified Liabilities (x) that a court of competent jurisdiction determines arose on account of the relevant Indemnified Party's gross negligence or wilful misconduct, (y) that constitute loss of profit, loss of income or revenue or loss of business opportunity of such Indemnified Party or (z) that would have been paid, incurred or suffered by or asserted against the Indemnified Parties or any of them in the absence of the Loan Documents and the arrangements contemplated thereby.

(c) Each Indemnified Party shall notify the relevant Borrower as soon as reasonably practicable upon becoming aware of facts which the Indemnified Party believes in good faith could give rise to a claim under this Section 8.5. No Indemnified Party shall settle or pay any third party claim for which indemnification may be sought except with the prior written consent of the relevant Borrower. The relevant Borrower shall have the right to participate in or assume control of the defence of any third party claim, with the advice of counsel satisfactory to such Borrower. To the extent an Indemnified Party shall have rights against any third party, including an insurer, with respect to an indemnified matter hereunder, such Indemnified Party shall make such claim and promptly remit the proceeds thereof to reimburse such Borrower for amounts paid by them under this Section 8.5 in respect of such matter; provided, however, that such Indemnified Party shall only be obligated to remit any such proceeds to the extent it has received payment in full from such Borrower with respect to such indemnified matter.

(d) All obligations provided for in this Section 8.5 shall survive the permanent repayment of all of the outstanding credit hereunder and the termination of the Credit Facility and this Agreement and shall not be reduced or impaired by any investigation made by or on behalf of the Agent, the Lenders or any of them.

(e) Each Borrower hereby agrees that, for the purposes of effectively allocating the risk of loss placed on such Borrower by this Section 8.5, the Agent and each Lender shall be deemed to be acting as the agent or trustee on behalf of and for

the benefit of their respective shareholders, officers, directors, employees and agents.

(f) If, for any reason, the obligations of a Borrower pursuant to this Section 8.5 shall be unenforceable, such Borrower agrees to make the maximum contribution to the payment and satisfaction of each obligation that is permissible under applicable Law, except to the extent that a court of competent jurisdiction determines such obligations arose on account of the gross negligence or wilful misconduct of any Indemnified Party.

(g) The obligations of each Borrower for any payment under this Section 8.5 shall be several obligations.

8.6 Gross-Up for Taxes

(a) (i) All payments made by the Borrowers under this Agreement shall be made free and clear of, and without deduction or withholding for or on account of, any Taxes except to the extent that such deduction or withholding is required by any applicable Law, as modified by the administrative practice of any relevant Governmental Authority then in effect. If any such Taxes are required to be withheld by a particular Borrower from any amount payable to the Agent or any Lender hereunder, or if the Agent or any Lender is subject to Taxes under Part XIII of the Tax Act (or any successor part) in respect of any such amount but such Taxes are not levied by way of deduction or withholding ("**Part XIII Tax Payable**"), such Borrower shall:

(A) promptly notify the Agent of such requirement;

(B) (I) pay to the relevant Governmental Authority the full amount required to be deducted or withheld (including the full amount of Taxes required to be deducted or withheld from any additional amount paid by such Borrower to the Agent or such Lender under this Section 8.6(a)), or, as the case may be,

(II) (a) pay to the relevant Governmental Authority, or

(b) if such Borrower has not been provided by the Agent or such Lender with any authorization and/or particulars that are required for such Borrower to make such payment to the relevant Governmental Authority, pay to the Agent or such Lender, as the case may be,

the full amount of any Part XIII Tax Payable in respect of such amount (including the full amount of Part XIII Tax Payable on any additional amount paid by such Borrower to the Agent or such Lender under this Section 8.6(a)). If (I) or (II)(a) applies, such

Borrower shall pay such amount to such Governmental Authority within the time period required by applicable Law for Taxes referred to in (I) that are required to be deducted or withheld. If (II)(b) applies, such Borrower shall pay such amount to the Agent or such Lender, as applicable, at least three Business Days before the expiration of the aforementioned time period;

(C) as promptly as possible thereafter, forward to the Agent and such Lender an official receipt (or a certified copy), or other documentation reasonably acceptable to the Agent and such Lender, evidencing any such payment to such Governmental Authority; and

(D) pay to the Agent or such Lender, in addition to the payment to which the Agent or such Lender is otherwise entitled under this Agreement, such additional amount as is necessary to ensure that the net amount actually received by the Agent or such Lender (free and clear of and net of any such Taxes (including the full amount of any Part XIII Tax Payable), whether assessable against such Borrower, the Agent or such Lender) will equal the full amount the Agent or such Lender would have received had no such deduction or withholding been required or no Part XIII Tax Payable been levied, as the case may be.

(ii) If a particular Borrower fails to pay to the relevant Governmental Authority or the Agent or any Lender within the time period referenced in Section 8.6(a)(i)(B) any Taxes that it was required to pay to such Governmental Authority or the Agent or such Lender, as applicable, under this Section 8.6(a) in respect of any payment to or for the benefit of the Agent or any Lender under this Agreement or fails to furnish the Agent or such Lender, as applicable, with the documentation referred to in Section 8.6(a) when required to do so, such Borrower shall forthwith on demand fully indemnify the Agent or such Lender, as applicable, on an after-Taxes basis, from and against any Taxes (including interest and penalties), losses and expenses which the Agent or such Lender may suffer or incur as a result of such failure.

(iii) Each of the Borrowers shall also severally indemnify the Agent and each Lender, on an after-Taxes basis, for any additional Taxes on net income (including interest and penalties in respect thereof) that the Agent or such Lender may be obliged to pay as a result of the payment of additional amounts under this Section 8.6(a) within ten (10) days from the date the Agent or such Lender, as applicable, makes written demand therefor, accompanied by a certificate stating the amount of the relevant Taxes, including interest and/or penalties, and the computation thereof, which certificate shall (absent manifest error) be conclusive.

(iv) The Borrowers' obligations under this Section 8.6(a) shall survive the termination of the Credit Facility and this Agreement and the permanent repayment of the outstanding credit and all other amounts payable hereunder for a period of 10 years.

(b) Notwithstanding Section 8.6(a), no Borrower shall be required to indemnify or pay any additional amounts in respect of Taxes (including, for greater certainty, Part XIII Tax Payable) applicable to any amount payable with respect to any outstanding credit or portion thereof pursuant to Section 8.6(a) above to any Lender that is not a Canadian Qualified Lender, unless such outstanding credit or portion thereof, as the case may be, was assigned, participated or transferred to such Lender at the request of a Borrower, or was assigned, participated or transferred to such Lender following the occurrence of and during the continuance of an Event of Default.

(c) If a particular Borrower determines in good faith that a reasonable basis exists for contesting any Taxes for which a payment has been made hereunder, the relevant Lender or the Agent, as applicable, shall cooperate with such Borrower in challenging such Taxes at such Borrower's expense if so requested by such Borrower. If any Lender or the Agent, as applicable, receives a refund of, or credit for, Taxes for which a payment has been made by a particular Borrower pursuant to this Agreement, which refund or credit in the good faith judgment of such Lender or the Agent, as the case may be, is attributable to such payment made by such Borrower, then the Lender or the Agent, as the case may be, shall reimburse such Borrower for such amount as the Lender or the Agent, as the case may be, determines to be the proportion of the refund or credit as will leave it, after such reimbursement, in no better or worse position than it would have been in if such Taxes had not been exigible. A Lender or the Agent shall claim any refund or credit that it determines is available to it, unless it concludes in its reasonable discretion that it would be adversely affected by making such a claim. Neither the Lender nor the Agent shall be obliged to disclose any information regarding its tax affairs or computations to such Borrower in connection with this paragraph (c) or any other provision of this Section 8.6, except to the extent necessary for determining the basis for any amounts required to be indemnified by such Borrower under this Section 8.6.

ARTICLE 9
REPAYMENTS AND PREPAYMENTS

9.1 Repayment. The aggregate credit outstanding under the Credit Facility which has been extended to a particular Borrower, together with all accrued but unpaid interest thereon and all accrued but unpaid fees with respect thereto, shall be repaid in full by such Borrower to the Lenders on the Maturity Date. As concerns any Letter which, on the Maturity Date, has an expiry date later than the Maturity Date, the relevant Borrower shall pay to the Agent, for the account of the Lenders, or the Fronting Lender, as the case may be, on the Maturity Date, the then contingent liability of the Lenders thereunder (to be held solely for the purpose of satisfying any draw under such Letter and to be held subject to Section 13.2). Following such payment by

the relevant Borrower to the Agent, for the account of the Lenders, or the Fronting Lender, as the case may be, such Borrower shall have no further liability to the Lenders with respect to any such Letter. Amounts which are repaid as aforesaid may not be reborrowed.

9.2 Voluntary Prepayments. The Borrowers shall be entitled, at their option and upon two Business Days' irrevocable notice to the Agent, to prepay all or any portion of any outstanding credit at any time provided that (i) Section 8.4 shall be complied with in connection with any such prepayment, (ii) Bankers' Acceptances and BA Rate Loans may only be prepaid on their maturity and (iii) any such prepayment of all or any portion of any outstanding Loan under the Credit Facility shall be in an amount of no less than $1,000,000 and otherwise in multiples of $100,000.

9.3 Reimbursement Obligation for Maturing Bankers' Acceptances. Each Borrower hereby unconditionally agrees to pay to each Lender on the maturity date (whether at stated maturity, by acceleration or otherwise) of each Bankers' Acceptance of such Borrower accepted by such Lender the undiscounted face amount of such then-maturing Bankers' Acceptance. The obligation of such Borrower to reimburse the Lenders for then-maturing Bankers' Acceptances of such Borrower may be satisfied by such Borrower by:

(a) paying to the Lenders, in accordance with Section 3.7, on the maturity date of such Bankers' Acceptances an amount equal to the aggregate undiscounted face amount thereof, provided that such Borrower shall notify the Agent of its intention to reimburse the Lenders in such manner prior to 11:00 a.m. (Toronto time) on such maturity date;

(b) replacing such maturing Bankers' Acceptances with new Bankers' Acceptances in accordance with Section 5.1; or

(c) converting such maturing Bankers' Acceptances into a Prime Rate Loan in accordance with Section 6.2.

In no event shall such Borrower claim from the Lenders any grace period with respect to the aforesaid obligation of such Borrower to reimburse the Lenders.

9.4 Reimbursement or Conversion on Presentation of Letters.

(a) On presentation of a Letter and payment thereunder by the Fronting Lender, the relevant Borrower shall forthwith pay to the Agent for the account of the Fronting Lender, and thereby reimburse the Fronting Lender for, all amounts paid by the Fronting Lender pursuant to such Letter; failing such payment, such Borrower shall be deemed to have effected a conversion of such Letter into a Prime Rate Loan to the extent of the payment of the Fronting Lender thereunder.

(b) If the Fronting Lender makes payment under any Letter and the relevant Borrower does not fully reimburse the Fronting Lender on or before the date of payment, then Section 9.4(a), shall apply to deem a Prime Rate Loan to be outstanding to the relevant Borrower under the Credit Facility in the manner therein set out. Each Lender shall, on request by the Fronting Lender, immediately pay to the

Fronting Lender an amount equal to such Lender's Pro Rata Share of the amount paid by the Fronting Lender such that each Lender is participating in the deemed Prime Rate Loan, in accordance with its Pro Rata Share.

(c) Each Lender shall immediately on demand indemnity the Fronting Lender to the extent of such Lender's Pro Rata Share of any amount paid or liability incurred by the Fronting Lender under each Letter issued by it to the extent that a Borrower does not fully reimburse the Fronting Lender therefore.

9.5 Letters Subject to an Order. The Borrower shall pay to the Fronting Lender an amount equal to the maximum amount available to be drawn under any unexpired Letter which becomes the subject of any Order, such payment to be due forthwith upon demand.

9.6 Repayment of Credit Excess. Each of the Borrowers shall repay to the Agent for the account of the Lenders on demand by the Agent that portion of the amount of any Credit Excess existing from time to time which is equal to the percentage that the sum of the aggregate principal amount of Loans, the aggregate outstanding face amount of Bankers' Acceptances and the aggregate outstanding face amount of the Letters drawn by such Borrower at such time is of the sum of the total aggregate utilization of credit hereunder by all of the Borrowers at such time, any such repayment to be made no later than one Business Day after the making of such demand.

9.7 Currency of Repayment. All payments and repayments of outstanding credit hereunder shall be made in the currency of such outstanding credit.

ARTICLE 10
REPRESENTATIONS AND WARRANTIES

10.1 Representations and Warranties. To induce the Agent and the Lenders to enter into this Agreement and to extend credit to the Borrowers hereunder, each Borrower in regard to itself only, and the Guarantor in regard to itself and each other Obligor, hereby represents and warrants to the Agent and the Lenders as at the date hereof, as at the date of each extension of credit hereunder and as of the last day of each Fiscal Quarter (provided, however, the representation and warranty set forth in Section 10.1(m) shall only be made on the Closing Date), as follows and acknowledges and confirms that the Agent and the Lenders are relying upon such representations and warranties in executing this Agreement and in extending credit hereunder:

(a) **Organization; Powers.** Each Obligor is duly incorporated, amalgamated or continued and is organized, validly existing and in good standing under the Laws of the jurisdiction of its organization, has all requisite corporate power and authority to carry on its business as now conducted and, except where the failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change, is qualified to do business in, and is in good standing in, every jurisdiction where such qualification is required.

(b) **Authorization; Enforceability.** The execution and delivery by each Obligor of the Loan Documents to which it is a party and the performance of its obligations hereunder and thereunder are within such Obligor's corporate powers and have

been duly authorized by all necessary corporate and, if required, shareholder action. This Agreement and the other Loan Documents have been duly executed and delivered by each Obligor party thereto and constitute legal, valid and binding obligations of such Obligor, enforceable in accordance with their respective terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other Laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at Law.

(c) **Governmental Approvals; No Conflicts.** The execution and delivery of the Loan Documents and the performance of each Obligor's obligations hereunder and thereunder (a) do not require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority that have not been obtained, made or taken (except for normal course post-closing filings under applicable securities Laws or stock exchange rules, which the Obligor will make within the required time frames and except for consents and approvals for the financing contemplated herein which the Obligor will obtain prior to the Closing Date), (b) will not violate in any material respect any applicable Law or the articles and by-laws of the Obligor or any order of any Governmental Authority, (c) will not violate or result in a default under any indenture, agreement or other instrument binding upon the Obligor or its assets, or give rise to a right thereunder to require any payment to be made by the Obligor, and (d) will not result in the creation or imposition of any Lien on any asset of such Obligor.

(d) **Financial Condition.**

(i) As of the date hereof, each Obligor has furnished to the Lenders the financial statements that it otherwise would have been required to deliver to the Agent pursuant to Sections 11.1(b)(i) and (ii) in connection with the Fiscal Year ended December 31, 2011. Such financial statements present fairly, in all material respects, the financial position and results of operations and cash flows of such Obligor as of such dates and for such periods in accordance with GAAP. Thereafter, each Obligor has furnished to the Lenders the financial statements required to be delivered by it to the Agent pursuant to Sections 11.1(b)(i) and (ii). The most recent audited annual financial statements and unaudited quarterly financial statements so delivered present fairly, in all material respects, the financial position and results of operations and cash flows of each Obligor as of such dates and for such periods in accordance with GAAP.

(ii) The fiscal year of each Obligor ends on December 31 of each calendar year.

(e) **Litigation.**

(i) Other than as previously disclosed to the Agent or the Lenders and confirmed by way of letter dated the date hereof, there are no actions, suits

or proceedings (including any Tax-related matter) by or before any arbitrator or Governmental Authority pending against or, to the knowledge of each Obligor, threatened against or affecting any Obligor (i) as to which there is a reasonable possibility of an adverse determination and that, if adversely determined, could reasonably be expected, individually or in the aggregate, to result in a Material Adverse Change, or (ii) that involve the Loan Documents.

(ii) Except with respect to any matters that, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change, no Obligor (i) has failed to comply with any Environmental Law or to obtain, maintain or comply with any permit, licence or other approval required under any Environmental Law, (ii) has become subject to any Environmental Liability, (iii) has received notice of any claim with respect to any Environmental Liability, or (iv) knows of any basis for which any Environmental Liability would reasonably be expected to arise.

(f) **Compliance with Laws and Agreements**. Each Obligor is in compliance with all Laws (including Environmental Laws) applicable to it or its property and all indentures, agreements and other instruments binding upon it or its property, except where the failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change. No Obligor has violated or failed to obtain any Authorization necessary to the ownership of any of its property or assets or the conduct of its businesses, which violation or failure could reasonably be expected to result in (in the event that such a violation or failure were asserted by any Person through appropriate action) a Material Adverse Change.

(g) **Taxes.** Each Obligor has timely filed or caused to be filed all Tax returns and reports required to have been filed and (x) has paid or caused to be paid all Taxes required to have been paid by it, (y) has accrued as a liability all such Taxes on its books or (z) has disclosed in its financial statements (including, without limitation, in the notes thereto) all such Taxes, other than Taxes that are being contested in good faith by appropriate proceedings and for which such Obligor has set aside on its books adequate reserves, except to the extent in each case that any failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change.

(h) **Title to Real Property.** Each Obligor has indefeasible fee simple title to its material owned real properties (if any), and with respect to leased real properties, indefeasible title to the leasehold estate with respect thereto, pursuant to valid and enforceable leases, and its title to its owned and leased real properties is free and clear of all Liens except Permitted Liens.

(i) **Title to Personal Property.** Except to the extent not in the aggregate materially adverse to the relevant Obligor's financial condition or operations, each Obligor has title to its owned personal property, and with respect to leased personal

properties, title to the leasehold estate with respect thereto, pursuant to valid and enforceable leases, and its title to its owned and leased personal property is free and clear of all Liens except Permitted Liens.

(j) **No Defaults under Other Instruments.** No Obligor is in default nor has any event or circumstance occurred which, but for the passage of time or the giving of notice, or both, would constitute a default (in any respect that would result in a Material Adverse Change) under any loan or credit agreement, indenture, mortgage, deed of trust, security agreement or other instrument or agreement evidencing or pertaining to any Indebtedness for Borrowed Money of such Obligor, or under any material agreement or instrument to which such Obligor is a party or by which such Obligor is bound.

(k) **No Defaults Hereunder.** No Default has occurred and is continuing.

(l) **Subsidiaries.** Neither CNPI nor Cornwall has any Subsidiaries. The sole subsidiary of API is 1228158 Ontario Limited. As at the date of this Agreement, the Guarantor has no Subsidiaries other than the Borrowers and FortisOntario District Heating Inc., Gananoque Water Power Company, Grimsby Power Inc., Rideau St. Lawrence Holdings Inc. and Westario Power Holdings Inc.

(m) **No Material Adverse Change.** There has occurred no Material Adverse Change since December 31, 2011.

(n) **Employee Benefit Plans.** Each Obligor has maintained all of its benefit and pension plans in all material respects in accordance with all applicable legal requirements.

(o) **Insurance.** Insurance is being maintained by, or on behalf of, each Obligor in accordance with Section 11.1(i). Each such insurance policy maintained by, or on behalf of, each Obligor is in full force and effect.

(p) **Unsecured Debt.** The Credit Facility ranks *pari passu* with all other unsecured Indebtedness for Borrowed Money of each of the Borrowers. The Guarantee granted under this Agreement by the Guarantor ranks *pari passu* with all other unsecured Indebtedness for Borrowed Money of the Guarantor.

(q) **Existing CIBC Indebtedness.** The Existing CIBC Indebtedness is the only Indebtedness for Borrowed Money owing by the applicable Obligors under the Existing CIBC Facility Agreements as of the Closing Date.

10.2 Survival of Representations and Warranties. All of the representations and warranties of the Obligor contained in Section 10.1 shall survive the execution and delivery of this Agreement and shall continue until all credit outstanding hereunder has been repaid and the Credit Facility and this Agreement have been terminated notwithstanding any investigation made at any time by or on behalf of the Agent or any of the Lenders.

ARTICLE 11
COVENANTS

11.1 Affirmative Covenants. Each Borrower, in regard to itself only, and the Guarantor in regard to itself and each other Obligor, hereby covenants and agrees with the Agent and the Lenders that, until all credit outstanding hereunder has been repaid in full and the Credit Facility and this Agreement have been terminated and unless the Lenders have otherwise consented thereto in writing in accordance with Section 14.14:

(a) **Prompt Payment**. Such Obligor shall and the Guarantor shall cause each other Obligor to duly and punctually pay or cause to be paid to the Lenders and the Agent all amounts payable under each Loan Document at the dates and places, in the currency and in the manner mentioned herein.

(b) **Financial Statements and Other Information.** Such Obligor shall and the Guarantor shall cause each other Obligor to furnish to the Agent (with sufficient copies for each Lender):

(i) **Annual Financial Statements**. As soon as available and in any event within 120 days after the end of each Fiscal Year of such Obligor, its audited consolidated and, with respect to the Guarantor only, unaudited unconsolidated, balance sheet and related statements of income, retained earnings and cash flow as of the end of and for such Fiscal Year, setting forth in each case in comparative form the figures for the previous Fiscal Year, all reported on by independent auditors of recognized national standing in the applicable jurisdiction (without a "going concern" or like qualification or exception and without any qualification or exception as to the scope of such audit) to the effect that such financial statements present fairly in all material respects the financial condition and results of operations of such Obligor in accordance with GAAP consistently applied;

(ii) **Quarterly Financial Statements**. As soon as available and in any event within 60 days after the end of each of the first three Fiscal Quarters of each Fiscal Year of such Obligor, its consolidated and, with respect to the Guarantor only, unconsolidated unaudited balance sheet and related statements of income, retained earnings and cash flow as of the end of and for such Fiscal Quarter and the then elapsed portion of the Fiscal Year which includes such Fiscal Quarter, setting forth in each case in comparative form the figures for the corresponding period or periods of (or, in the case of the balance sheet, as of the end of) the previous Fiscal Year, all certified by a Responsible Officer as presenting fairly in all material respects the financial condition and results of operations of such Obligor in accordance with GAAP consistently applied and subject to normal year end audit adjustments;

(iii) **Compliance Certificates**. Concurrently with the financial statements required pursuant to Sections 11.1(b)(i) and (i) above, a certificate of each

Borrower, signed by a Responsible Officer of such Borrower (A) confirming fulfillment of such Borrower's obligations under this Agreement and the other Loan Documents and demonstrating in reasonable detail compliance (including showing all material calculations) as at the end of the most recently completed Fiscal Year or the most recently completed Fiscal Quarter, with the financial covenant in Section 11.1(j), and (B) containing or accompanied by such financial or other details, information and material as the Agent may reasonably request to evidence such compliance, which certificate shall be substantially in the form of Schedule B hereto;

(iv) **Other Information**. Promptly after the same become publicly available, copies of all press releases relating to material change reports, prospectuses, proxy statements and other materials filed out of the ordinary course by such Obligor with any securities commission, stock exchange or similar entity, and all materials distributed out of the ordinary course by such Obligor to its shareholders and which relate to matters in which the Lenders, in such capacities, can reasonably be expected to have an interest. Promptly following receipt by such Obligor of the Agent's request, such additional financial or operating reports, statements or information as the Agent may, from time to time, reasonably request.; and

(v) **Notices of Default**. Promptly after any Responsible Officer of such Obligor learns of the receipt or occurrence of any of the following, a certificate of such Obligor, signed by a Responsible Officer, specifying (A) any official notice of any violation, possible violation, non-compliance or possible non-compliance, or claim made by any Governmental Authority pertaining to all or any part of the properties of such Obligor which could reasonably be expected to result in a Material Adverse Change, (B) any event which constitutes a Default or Event of Default, together with a detailed statement specifying the nature thereof and the steps being taken to cure such Default or Event of Default, (C) the receipt of any notice from, or the taking of any other action by, the holder of any promissory note, debenture or other evidence of Indebtedness for Borrowed Money of such Obligor in an amount in excess of $2,000,000 with respect to an actual or alleged default, together with a detailed statement specifying the notice given or other action taken by such holder and the nature of the claimed default and what action such Obligor is taking or proposes to take with respect thereto, (D) any event, development or condition which may reasonably be expected to result in a Material Adverse Change, (E) any representation and warranty in Section 10.1 (with Section 10.1(d)(i) being amended to refer to the most recent financial statements delivered to the Agent) ceasing to be true and correct at such time or (F) the commencement of, or any material development in, any litigation or proceeding affecting such Obligor, in each case which has resulted or is reasonably likely to result in a Material Adverse Change.

(c) **Existence; Conduct of Business**. Such Obligor shall and the Guarantor shall cause each other Obligor to do or cause to be done all things necessary to preserve, renew and keep in full force and effect its legal existence and the rights, licences, permits, privileges and franchises material to the conduct of its business (including, without limitation, the making of all necessary regulatory filings), except to the extent that the failure to do so could not reasonably be expected to result in a Material Adverse Change.

(d) **Payment of Obligations.** Such Obligor shall and the Guarantor shall cause each other Obligor to pay its obligations, including Tax liabilities (other than Tax liabilities that such Obligor has accrued as a liability on its books or has disclosed in its financial statements (including, without limitation, in the notes thereto)), that, if not paid, could reasonably be expected to result in a Material Adverse Change, before the same shall become delinquent or in default, except where (i) the validity or amount thereof is being contested in good faith by appropriate proceedings, (ii) such Obligor has set aside on its books adequate reserves with respect thereto in accordance with GAAP, and (iii) any failure to make payment pending such contest, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change.

(e) **Books and Records; Inspection Rights**. Such Obligor shall and the Guarantor shall cause each other Obligor to keep proper books of record and account in which full, true and correct entries are made of all dealings and transactions in relation to its business and activities. Such Obligor shall and the Guarantor shall cause each other Obligor to permit any representatives designated by the Agent, upon reasonable prior notice and during normal business hours, but not more than once in any year so long as no Default has occurred and is continuing, to visit and inspect its properties, to examine and make extracts from its books and records, and to discuss its affairs, finances and condition with its officers and independent auditors.

(f) **Compliance with Laws**. Such Obligor shall and the Guarantor shall cause each other Obligor to comply with all Laws (including, without limitation, all Environmental Laws) and Authorizations applicable to it or its property, except where any failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change.

(g) **Use of Proceeds**. The proceeds of the credit extended hereunder shall be used solely by each Borrower for general corporate purposes, including, without limitation, to support letter of credit obligations of such Borrower.

(h) **Further Assurances.** Such Obligor shall and the Guarantor shall cause each other Obligor to cure promptly any defects in the execution and delivery of the Loan Documents, including this Agreement. Such Obligor shall and the Guarantor shall cause each other Obligor to, at its expense, as promptly as practical, execute and deliver to the Agent, upon request, all such other and further documents, agreements and instruments in compliance with or

performance of the covenants and agreements of such Obligor in the Loan Documents, all as may be necessary in connection therewith.

(i) **Insurance.** Such Obligor shall and the Guarantor shall cause each other Obligor to maintain or cause to be maintained, with financially sound and reputable insurers, insurance with respect to its properties and business against such liabilities, casualties, risks and contingencies and in such types and amounts as is customary in the case of Persons engaged in the same or similar businesses and similarly situated and in accordance with any requirement of any Governmental Authority, except to the extent that any failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Change.

(j) **CNPI Financial Covenant.** CNPI shall and the Guarantor shall cause CNPI to ensure that the Debt to Capitalization Ratio of CNPI does not exceed 0.75:1 at any time.

(k) **Cornwall Financial Covenant.** Cornwall shall and the Guarantor shall cause Cornwall to ensure that the Debt to Capitalization Ratio of Cornwall does not exceed 0.75:1 at any time.

(l) **API Financial Covenant.** API shall and the Guarantor shall cause API to ensure that the Debt to Capitalization Ratio of API does not exceed 0.75:1 at any time.

(m) **Reimbursement of Expenses.** Each Obligor shall and the Guarantor shall cause each other Obligor to reimburse the Agent, on demand, for all reasonable out-of-pocket costs, charges and expenses incurred by it or on its behalf (including, without limitation, the fees and out-of-pocket disbursements of its consultants and its legal counsel and travel expenses) in connection with the Agent's due diligence investigation (whenever conducted), the negotiation, preparation, execution, delivery, syndication, post-closing advertising agreed to by the Borrowers, interpretation and enforcement of the Loan Documents and all other documentation ancillary to the completion of the transactions contemplated hereby and thereby and any amendments hereto or thereto and any waivers of any provisions hereof or thereof (whether or not consummated or entered into), provided that all out-of-pocket costs, charges and expenses shall be evidenced by appropriate documentation, including detailed billing summaries with respect to fees of legal counsel.

(n) **Existing CIBC Indebtedness.** The applicable Borrowers shall and the Guarantor shall cause each other applicable Obligor to, provide evidence to the Agent of the payment in full and cancellation of the Existing CIBC Indebtedness no later than July 11, 2012.

11.2 Performance of Covenants by Agent. The Agent may, upon notice by the Agent to the Obligors, perform any covenant of any of the Obligors under any Loan Document which any Obligor fails to perform or cause to be performed and which the Agent is capable of

performing, including any covenants the performance of which requires the payment of money, provided that the Agent shall not be obligated to perform any such covenant on behalf of any Obligor and no such performance by the Agent shall require the Agent to further perform any Obligor's covenants or shall operate as a derogation of the rights and remedies of the Agent or the Lenders under this Agreement or as a waiver of such covenant by the Majority Lenders. Any amounts paid by the Agent as aforesaid shall be repaid by the Obligors to the Agent on demand.

11.3 Restrictive Covenants. Each Borrower, in regard to itself only, and the Guarantor in regard to itself and each other Obligor, hereby covenants and agrees with the Agent and the Lenders that, until all credit outstanding hereunder has been repaid in full and the Credit Facility and this Agreement have been terminated and unless the Lenders have otherwise consented thereto in writing in accordance with Section 14.14:

(a) **Liens.** No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to create, incur, assume or permit to exist any Lien on any property or asset now owned or hereafter acquired by the such Obligor, except Permitted Liens.

(b) **Fundamental Changes.**

(i) No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to merge into or consolidate with any other Person, or permit any other Person to merge into or consolidate with it, or sell, transfer, lease or otherwise dispose of (in one transaction or in a series of transactions) all or substantially all of its assets, or all or any of the stock of any other Obligor (in each case, whether now owned or hereafter acquired), or liquidate or dissolve, except that, if at the time thereof and immediately after giving effect thereto, no Default or Event of Default shall have occurred and be continuing, (A) any Obligor may amalgamate with any other Obligor and (B) any Obligor may sell, transfer, lease or otherwise dispose of all or substantially all of its assets to another Obligor.

(ii) No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to engage to any material extent in any material business that is materially different from businesses of the type conducted by such Obligor on the date of the execution of this Agreement, and businesses reasonably related or incidental thereto.

(c) **Indebtedness for Borrowed Money.** No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to create, incur, assume or permit to exist any Indebtedness for Borrowed Money of such Obligor, except:

(i) any Indebtedness for Borrowed Money of such Obligor created under the Loan Documents;

(ii) the indebtedness set forth in Schedule G;

(iii) any Purchase Money Obligation of such Obligor;

(iv) Indebtedness for Borrowed Money of such Obligor incurred by such Obligor in connection with a VISA or other credit card facilities provided that the aggregate amount so incurred by any Obligor shall not at any time exceed $500,000; and

(v) any additional Indebtedness for Borrowed Money incurred by such Obligor provided that (A) at the time of the incurrence thereof, no Default has occurred and is continuing, (B) no Default would arise immediately after or as a result of the incurrence thereof, (C) there would not be a breach of any of Sections 11.1(j), 11.1(k) or 11.1(l), as applicable, immediately after giving effect to the incurrence thereof and (D) such Obligor has given the Agent, prior to the incurrence thereof, a certificate detailing such incurrence and evidencing compliance with clauses (A) to (C) above.

(d) **Guarantees.** Subject to Section 11.3(g), no Obligor shall and the Guarantor shall not suffer or permit any other Obligor to Guarantee any obligations of any other Person, other than the Guarantee granted by the Guarantor under this Agreement and (i) any Guarantee resulting from the endorsement of negotiable instruments for collection in the ordinary course of business or (ii) any Guarantee that is permitted pursuant to the OEB Affiliate Relationships Code.

(e) **Restricted Payments.** Upon the occurrence and during the continuance of any Default or Event of Default, no Obligor shall and the Guarantor shall not suffer or permit any other Obligor to declare, pay, make, or agree to pay or make, directly or indirectly, any Restricted Payment.

(f) **Transactions with Affiliates.** No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to sell, lease or otherwise transfer any property or assets to, or purchase, lease or otherwise acquire any property or assets from, or otherwise engage in any other transactions with, any of its Affiliates, except in the ordinary course of business at prices and on terms and conditions not less favourable to such Obligor than could be obtained on an arm's-length basis from unrelated third parties. No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to enter into any transaction or series of transactions with Affiliates of such Obligor, which involve an outflow of money or other property from such Obligor to an Affiliate of such Obligor, including payment of management fees, affiliation fees, administration fees, compensation, salaries, asset purchase payments or any other type of fees or payments similar in nature, other than on terms and conditions substantially as favourable to such Obligor as would be obtainable by such Obligor in a reasonably comparable arm's-length transaction with a Person other than an Affiliate of such Obligor. The foregoing restrictions shall not apply to (A) any other transaction with any employee, officer or director of such Obligor pursuant to employee profit sharing and/or benefit plans and compensation and non-competition arrangements in amounts customary for corporations similarly situated to such Obligor and entered into in the ordinary course of business and approved by the board of directors of such Obligor,

(B) any reimbursement of reasonable out-of-pocket costs incurred by an Affiliate of such Obligor on behalf of or for the account of such Obligor, or (C) payments in connection with any shared services arrangements that are permitted by the applicable Ontario Regulator by any Borrower to the Guarantor or to Fortis Inc. and payments of not more than $1,000,000 annually in connection with any shared services arrangements by the Guarantor to Fortis Inc.

(g) **Intercorporate Loans and Guarantees.** No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to lend any amount to any Affiliate or Guarantee any obligation of any Affiliate except Guarantees permitted under Section 11.3(d), loans from the Guarantor to a Borrower or from a Borrower to the Guarantor, (iii) loans from an Obligor to Fortis Inc. or from Fortis Inc. to an Obligor and (iv) loans from a Borrower to another Borrower made in the ordinary course of business.

(h) **Disposition of Assets.** No Obligor shall and the Guarantor shall not suffer or permit any other Obligor to convey, sell, lease, assign, transfer or otherwise dispose of any of its property, business or assets (including sales of receivables and the sale portion of any sale-leaseback transaction), except that:

(i) any Obligor may sell, transfer or otherwise dispose of used or surplus equipment, vehicles, inventory or other assets in the ordinary course of business;

(ii) any Obligor may sell or discount without recourse accounts receivable arising in the ordinary course of business in connection with the compromise or collection thereof;

(iii) any Obligor may, subsequent to any acquisition, sell, transfer or otherwise dispose of a portion of the assets so acquired to the extent such Obligor determines such assets are not an essential part of such acquisition;

(iv) the Guarantor may sell or transfer CDH; and

(v) any Obligor may, subject always to Section 11.3(b)(i), otherwise sell, transfer or otherwise dispose of assets for fair value, provided that the aggregate consideration for all sales, transfers and disposals by such Obligor pursuant to this clause (v) during the term of this Agreement shall at no time exceed $1,000,000 (other than any sale, transfer or other disposition where the net proceeds therefrom are reinvested by such Obligor in its operations within the six month period following its receipt of such net proceeds).

(i) **Subsidiaries.** Neither CNPI nor Cornwall shall and the Guarantor shall not suffer or permit CNPI or Cornwall to have any Subsidiaries. API shall not, and the Guarantor shall not suffer or permit API to, have any Subsidiaries other than 1228158 Ontario Limited. The Guarantor shall not have any Subsidiaries other than the Borrowers, FortisOntario District Heating Inc., Gananoque Water Power

Company, Grimsby Power Inc., Rideau St. Lawrence Holdings Inc., Westario Power Inc. and Niagara Power Inc.

(j) **Existing CIBC Indebtedness.** The applicable Borrowers shall not and the Guarantor shall not suffer or permit the applicable Borrowers to permit any Indebtedness for Borrowed Money to be outstanding under the Existing CIBC Facility Agreements other than the Existing CIBC Indebtedness.

ARTICLE 12
CONDITIONS PRECEDENT TO OBTAINING CREDIT

12.1 Conditions Precedent to All Credit. The obligation of the Lenders to extend credit under the Credit Facility to a particular Borrower is subject to fulfilment of the following conditions precedent at the time such credit is extended:

(a) no Default with respect to such Borrower has occurred and is continuing or would arise immediately after giving effect to or as a result of such extension of credit;

(b) such Borrower shall have complied with the requirements of Article 4, 5 or 6, as the case may be, in respect of the relevant credit; and

(c) the representations and warranties made by such Borrower and the Guarantor in the Loan Documents shall be true and correct in all material respects on the date such credit is extended as if such representations and warranties were made on such date.

Section 12.1(a) does not apply to a deemed conversion of a Bankers' Acceptance into a Prime Rate Loan pursuant to Section 6.5. Section 12.1(c) does not apply to an extension of credit pursuant to a conversion or rollover.

12.2 Conditions Precedent to Initial Drawdown. The obligation of the Lenders to extend credit by way of drawdown for the first time is subject to the prior or concurrent fulfilment of the following conditions precedent at the time such credit is extended:

(a) the conditions precedent set forth in Section 12.1 have been fulfilled;

(b) the absence of any litigation, inquiry and investigation enjoining or restricting the Credit Facility;

(c) the Agent shall have received, in form and substance satisfactory to the Agent:

(i) a duly certified copy of the articles of incorporation and by-laws of the each Obligor;

(ii) a certificate of status or good standing for each Obligor issued by the appropriate governmental body or agency of the jurisdiction in which such Obligor is incorporated;

(iii) a duly certified copy of the resolution of the board of directors of each Obligor authorizing it to execute, deliver and perform its obligations under each Loan Document;

(iv) a certificate of an officer of each Obligor, in such capacity, setting forth specimen signatures of the individuals authorized to sign the Loan Documents to which it is a party;

(v) a certificate of the chief financial officer of each Obligor, in such capacity, certifying that, to the best of his or her knowledge after due inquiry, no Default has occurred and is continuing or would arise immediately after giving effect to or as a result of such extension of credit;

(vi) an opinion of the legal counsel to the Obligors, addressed to the Agent and the Agent's counsel, with respect to all matters as the Agent may reasonably request;

(vii) a certified copy of the API Trust Indenture; and

(viii) an opinion of the legal counsel to the Agent in each relevant jurisdiction, with respect to all matters as the Agent may reasonably request

(d) the Agent and its counsel, acting reasonably, shall be satisfied that all applicable Laws have been complied with in all material respects, all material agreements have been entered into and all necessary governmental, corporate and other third party consents (including, without limitation, all requisite approvals from the Ontario Regulators), acknowledgements, directions and approvals have been obtained with respect to the Loan Documents; and

(e) all amounts due and payable under the Loan Documents shall have been paid.

12.3 Waiver. The terms and conditions of Sections 12.1 and 12.2 are inserted for the sole benefit of the Agent and the Lenders and the Majority Lenders may waive them in whole or in part, with or without terms or conditions, in respect of any extension of credit, without prejudicing their right to assert them in whole or in part in respect of any other extension of credit.

ARTICLE 13
DEFAULT AND REMEDIES

13.1 Events of Default. Upon the occurrence of any one or more of the following events with respect to a particular Borrower (each, an "**Event of Default**") which is continuing, unless expressly waived in writing by the Majority Lenders or cured to the satisfaction of the Majority Lenders:

(a) such Borrower shall fail to repay outstanding credit hereunder when and as the same shall become due and payable, whether at the due date thereof or at a date fixed for prepayment thereof or otherwise;

(b) such Borrower or the Guarantor shall fail to pay any interest on any Loan or any fee or any other amount (other than an amount referred to in Section 13.1(a)) payable under any Loan Document, when and as the same shall become due and payable, and such failure shall continue unremedied for a period of three Business Days after notice thereof from the Agent to such Borrower or the Guarantor, as applicable;

(c) any representation or warranty made or deemed made by or on behalf of such Borrower or the Guarantor in or in connection with any Loan Document or any amendment or modification thereof or waiver thereunder, or in any report, certificate, financial statement or other document furnished pursuant to or in connection with any Loan Document or any amendment or modification thereof or waiver thereunder, shall prove to have been incorrect when made or deemed to be made unless such incorrect representation or warranty is capable of being corrected and such Borrower or the Guarantor, as applicable, acting in good faith, has commenced and is diligently pursuing the correction of such incorrect representation or warranty, in which case such Obligor shall have an additional 30 days to correct such incorrect representation or warranty;

(d) such Borrower or the Guarantor, as applicable, shall fail to observe or perform any covenant, condition or agreement contained in Section 11.1(b)(v)(B), 11.1(c), 11.1(g), 11.1(j), 11.1(k) or 11.1(l) or in Section 11.3 and such failure shall continue unremedied for a period of three Business Days after notice thereof from the Agent to such Borrower or the Guarantor, as applicable;

(e) such Borrower or the Guarantor, as applicable, shall fail to observe or perform any covenant, condition or agreement contained in any Loan Document to which it is a party (other than those specified in any of Section 13.1(a), (b), (c) or (d)) and such failure shall continue unremedied for a period of 30 days after notice thereof from the Agent to such Borrower or the Guarantor, as applicable, unless such failure is capable of being cured and such Borrower or the Guarantor, acting in good faith, has commenced and is diligently pursuing the curing of such failure, in which case such Borrower or the Guarantor, as applicable, shall have an additional 30 days to cure such failure;

(f) such Borrower or the Guarantor shall fail to observe or perform any covenant, condition or agreement contained in any agreement which entitles the other party to such agreement to terminate such agreement and that termination would reasonably be expected to result in Material Adverse Change;

(g) any obligation or obligations of such Borrower or the Guarantor in respect of Indebtedness for Borrowed Money in excess of $2,000,000 in the aggregate or the equivalent thereof in any other currency other than under the Loan Documents shall not be paid when due, or, if such Indebtedness for Borrowed Money contemplates a grace period, by the end of such grace period, or if such Indebtedness for Borrowed Money becomes (or becomes capable of being

declared) prematurely repayable by reason of a default unless such default has been remedied or cured, or waived by the appropriate debt holder;

(h) such Borrower or the Guarantor:

(i) becomes insolvent, or generally does not, or becomes unable to, pay its debts or meet its liabilities as the same become due, or admits in writing its inability to pay its debts generally, or declares any general moratorium on its indebtedness, or proposes a compromise or arrangement between it and any class of its creditors;

(ii) commits an act of bankruptcy under the *Bankruptcy and Insolvency Act* (Canada), or makes an assignment of its property for the general benefit of its creditors under such Act, or makes a proposal (or files a notice of its intention to do so) under such Act;

(iii) institutes any proceeding seeking to adjudicate it an insolvent, or seeking liquidation, dissolution, winding-up, reorganization, compromise, arrangement, adjustment, protection, moratorium, relief, stay of proceedings of creditors generally (or any class of creditors), or composition of it or its debts or any other relief, under any federal, provincial or foreign Law now or hereafter in effect relating to bankruptcy, winding-up, insolvency, reorganization, receivership, plans of arrangement or relief or protection of debtors under the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) or any comparable statute or at common law or in equity, or files an answer admitting the material allegations of a petition filed against it in any such proceeding;

(iv) applies for the appointment of, or the taking of possession by, a receiver, interim receiver, receiver/manager, sequestrator, conservator, custodian, administrator, trustee, liquidator or other similar official for it or any substantial part of its property; or

(v) ceases to carry on business, or threatens to do any of the actions described in this Section 13.1(h) or in Section 13.1(i), or takes any action, corporate or otherwise, to approve, effect, consent to or authorize any of the actions described in this Section 13.1(h) or in Section 13.1(i), or otherwise acts in furtherance thereof or fails to act in a timely and appropriate manner in defence thereof;

(i) any petition is filed, application made or other proceeding instituted against or in respect of such Borrower or the Guarantor:

(i) seeking to adjudicate it an insolvent;

(ii) seeking a receiving order against it under the *Bankruptcy and Insolvency Act* (Canada);

(iii) seeking liquidation, dissolution, winding-up, reorganization, compromise, arrangement, adjustment, protection, moratorium, relief, stay of proceedings of creditors generally (or any class of creditors), or composition of it or its debts or any other relief under any federal, provincial or foreign Law now or hereafter in effect relating to bankruptcy, winding-up, insolvency, reorganization, receivership, plans of arrangement or relief or protection of debtors under the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) or any comparable statute or at common law or in equity; or

(iv) seeking the entry of an order for relief or the appointment of, or the taking of possession by, a receiver, interim receiver, receiver/manager, sequestrator, conservator, custodian, administrator, trustee, liquidator or other similar official for it or any substantial part of its property;

and such petition, application or proceeding continues undismissed, or unstayed and in effect, for a period of 30 days after the institution thereof, provided that if an order, decree or judgment is granted or entered (whether or not entered or subject to appeal) against such Borrower or the Guarantor thereunder in the interim, such grace period will cease to apply, and provided further that if such Borrower or the Guarantor, as applicable, files an answer admitting the material allegations of a petition filed against it in any such proceeding, such grace period will cease to apply;

(j) any other event occurs which, under the Laws of any applicable jurisdiction, has an effect equivalent to any of the events referred to in either of Sections 13.1(h) or (j);

(k) one or more judgments for the payment of money in a cumulative amount in excess of $2,000,000 (or its equivalent) in the aggregate (but only to the extent not covered by insurance as to which the relevant insurance company has acknowledged to the Lenders coverage pursuant to a written confirmation to that effect satisfactory to the Agent, acting reasonably) is rendered against such Borrower or the Guarantor and such Borrower or the Guarantor, as applicable, has not (i) provided for its discharge in accordance with its terms within 30 days from the date of entry thereof, or (ii) procured a stay of execution thereof within 30 days from the date of entry thereof and within such period, or such longer period during which execution of such judgment has been stayed, appealed such judgment and caused the execution thereof to be stayed during such appeal, provided that if enforcement and/or realization proceedings are lawfully commenced in respect thereof in the interim, such grace period will cease to apply;

(l) any property of such Borrower or the Guarantor having a fair market value in excess of $2,000,000 (or its then equivalent) in the aggregate is seized (including by way of execution, attachment, garnishment, levy or distraint), or any Lien thereon securing Indebtedness for Borrowed Money in excess of $2,000,000 (or

its then equivalent) is enforced, in each case by any Person other than such Borrower or the Guarantor, continues in effect and is not released or discharged for more than 30 days or such longer period during which entitlement to the use of such property continues with such Borrower or the Guarantor, as applicable, and such Borrower or the Guarantor is contesting the same in good faith and by appropriate proceedings, provided that if the property is removed from the use of such Borrower or the Guarantor, as applicable, or is sold, in the interim, such grace period will cease to apply;

(m) one or more final judgments, not involving the payment of money and not otherwise specified in this Section 13.1(m), has been rendered against such Borrower or the Guarantor, the result of which could reasonably be expected to result in a Material Adverse Change, so long as such Borrower or the Guarantor, as applicable, has not (i) provided for its discharge in accordance with its terms within 30 days from the date of entry thereof, or (ii) procured a stay of execution thereof within 30 days from the date of entry thereof and within such period, or such longer period during which execution of such judgment has been stayed, appealed such judgment and caused the execution thereof to be stayed during such appeal, provided that if proceedings to seize or sell assets of such Borrower or the Guarantor, as applicable, are lawfully commenced in respect thereof in the interim, such grace period will cease to apply;

(n) any Loan Document is declared to be void or voidable as a result of any act or omission of such Borrower or the Guarantor or is repudiated by such Borrower or the Guarantor, or the validity, binding effect, legality or enforceability of any Loan Document is at any time contested by such Borrower or the Guarantor, or such Borrower or the Guarantor denies that it has any or any further liability or obligation hereunder or thereunder or any action or proceeding is commenced to enjoin or restrain the performance or observance by such Borrower or the Guarantor of any material terms of any Loan Document or to question the validity or enforceability of any Loan Document, or at any time it is unlawful or impossible for such Borrower or the Guarantor to perform any of its material obligations hereunder or thereunder; or

(o) Fortis Inc. ceases to own, directly or indirectly, beneficially and of record all of the issued and outstanding shares of such Borrower or the Guarantor;

the Agent (with the approval and instructions of the Majority Lenders) may, by notice to such Borrower, cease to make credit under the Credit Facility available to such Borrower and the Agent (with the approval and instructions of the Majority Lenders) may, by the same notice or by further notice to such Borrower, declare all indebtedness of such Borrower to the Agent and the Lenders pursuant to this Agreement (including (i) the present value of the face amount of all Bankers' Acceptances issued to such Borrower and outstanding hereunder based on their respective maturity dates, such present value to be calculated using a discount rate equal to the yield of Government of Canada treasury bills having a similar maturity date and (ii) the then contingent liability of the Lenders under all outstanding Letters issued at the request and upon the credit of such Borrower) and all unpaid interest and fees hereunder to be immediately due

and payable by such Borrower, whereupon credit under the Credit Facility shall cease to be available to such Borrower and all such indebtedness of such Borrower shall immediately become and be due and payable without further demand or other notice of any kind, all of which are expressly waived by such Borrower (provided, however, that credit under the Credit Facility shall cease to be available to such Borrower and all such indebtedness of such Borrower to the Agent and the Lenders shall automatically become due and payable, without notice of any kind, upon the occurrence of an event described in clause (i), (j) or (k) above). Upon the payment by such Borrower to the Lenders of the present value of the face amount of all Bankers' Acceptances of such Borrower issued and outstanding hereunder, such Borrower shall have no further liability to the Lenders with respect to such Bankers' Acceptances. Upon the payment by the relevant Borrower to the Agent, on behalf of the Lenders, or to the Fronting Lender, as the case may be, of the then contingent liability of the Lenders under all outstanding Letters issued on the credit of such Borrower, such Borrower shall have no further liability to the Lenders with respect to such Letters. In the event that the Lender is no longer required to make credit under the Credit Facility available to any of the Borrowers in accordance with the foregoing, the Credit Facility shall terminate.

13.2 Refund of Overpayments. With respect to each Letter for which the Agent, on account of the Lenders, or the Fronting Lender, as the case may be, has been paid all of the Lenders' contingent liability pursuant to Section 9.1, 9.4 or 13.1 and provided that all amounts due by the relevant Borrower to the Agent or the Fronting Lender, as the case may be, under Section 9.1, 9.4 or 13.1 have been paid, the Agent or the Fronting Lender, as the case may be, agrees to pay to such Borrower, upon the earlier of:

(a) the date on which either the original counterpart of such Letter is returned to the Agent or the Fronting Lender, as the case may be, for cancellation or the Lenders are released by the beneficiary thereof from any further obligations in respect of such Letter;

(b) the expiry of such Letter; and

(c) the Lenders are permanently enjoined by a court of competent jurisdiction from honouring such Letter pursuant to a final Order;

an amount equal to any excess of the amount received by the Agent, on account of the Lenders, or the Fronting Lender, as the case may be, hereunder in respect of its contingent liability under such Letter over the total of amounts applied to reimburse the Lenders for amounts paid by them under or in connection with such Letter (the Agent or the Fronting Lender, as the case may be, having the right to so appropriate such funds) together with interest thereon, at the rate applicable to short-term deposits, on amounts paid until applied or returned.

13.3 Remedies Cumulative. Each Borrower expressly agrees that the rights and remedies of the Agent and the Lenders under this Agreement are cumulative and in addition to and not in substitution for any rights or remedies provided by Law. Any single or partial exercise by the Agent or any of the Lenders of any right or remedy for a default or breach of any term, covenant or condition in this Agreement does not waive, alter, affect or prejudice any other right or remedy to which the Agent or such Lender may be lawfully entitled for the same default

or breach. Any waiver by the Agent or any of the Lenders of the strict observance, performance or compliance with any term, covenant or condition of this Agreement is not a waiver of any subsequent default and any indulgence by the Agent or any of the Lenders with respect to any failure to strictly observe, perform or comply with any term, covenant or condition of this Agreement is not a waiver of the entire term, covenant or condition or any subsequent default.

13.4 Set Off. In addition to any rights now or hereafter granted under applicable Law, and not by way of limitation of any such rights, the Agent and each Lender is authorized, after the occurrence of an Event of Default with respect to a particular Borrower and for so long as such Event of Default continues and without notice to such Borrower or to any other Person, any such notice being expressly waived by each Borrower, to set-off, appropriate and apply and any and all deposits, matured or unmatured, general or special, and any other indebtedness at any time held by or owing by the Agent or such Lender to or for the credit of or the account of such Borrower or the Guarantor against and on account of the obligations and liabilities of such Borrower or the Guarantor, as applicable, which are due and payable to the Agent or such Lender under this Agreement.

ARTICLE 14
THE AGENT

14.1 Appointment and Authorization of Agent. Each Lender hereby appoints and authorizes, and hereby agrees that it will require any assignee of any of its interests in the Loan Documents (other than the holder of a participation in its interests herein or therein) to appoint and authorize the Agent to take such actions as agent on its behalf and to exercise such powers under the Loan Documents as are delegated to the Agent by such Lender by the terms hereof, together with such powers as are reasonably incidental thereto. Neither the Agent nor any of its directors, officers, employees or agents shall be liable to any of the Lenders for any action taken or omitted to be taken by it or them thereunder or in connection therewith, except for its own gross negligence or wilful misconduct and each Lender hereby acknowledges that the Agent is entering into the provisions of this Section 14.1 on its own behalf and as agent and trustee for its directors, officers, employees and agents.

14.2 Interest Holders. The Agent may treat each Lender set forth in Schedule A hereto or the Person designated in the last instrument delivered to it under Section 16.6 as the holder of all of the interests of such Lender under the Loan Documents.

14.3 Consultation with Counsel. The Agent may consult with legal counsel selected by it as counsel for the Agent and the Lenders and shall not be liable to the Lenders for any action taken or not taken or suffered by it in good faith and in accordance with the advice and opinion of such counsel.

14.4 Documents. The Agent shall not be under any duty to the Lenders to examine, enquire into or pass upon the validity, effectiveness or genuineness of the Loan Documents or any instrument, document or communication furnished pursuant to or in connection with the Loan Documents and the Agent shall, as regards the Lenders, be entitled to assume that the same are valid, effective and genuine, have been signed or sent by the proper parties and are what they purport to be.

14.5 Agent as Lender. With respect to those portions of the Credit Facility made available by it, the Agent shall have the same rights and powers under the Loan Documents as any other Lender and may exercise the same as though it were not the Agent. The Agent and its Affiliates may accept deposits from, lend money to and generally engage in any kind of business with the Obligors and their Affiliates and Persons doing business with the Obligors and/or any of its Affiliates as if it were not the Agent and without any obligation to account to the Lenders therefor.

14.6 Responsibility of Agent. The duties and obligations of the Agent to the Lenders under the Loan Documents are only those expressly set forth herein. The Agent shall not have any duty to the Lenders to investigate whether a Default or an Event of Default has occurred. The Agent shall, as regards the Lenders, be entitled to assume that no Default or Event of Default has occurred and is continuing unless the Agent has actual knowledge or has been notified by any Obligor of such fact or has been notified by a Lender that such Lender considers that a Default or Event of Default has occurred and is continuing, such notification to specify in detail the nature thereof.

14.7 Action by Agent. The Agent shall be entitled to use its discretion with respect to exercising or refraining from exercising any rights which may be vested in it on behalf of the Lenders by and under this Agreement or any other Loan Document; provided, however, that the Agent shall not exercise any rights under Section 13.1 or under the Loan Documents expressed to be on behalf of or with the approval of the Majority Lenders without the request, consent or instructions of the Majority Lenders. Furthermore, any rights of the Agent expressed to be on behalf of or with the approval of the Majority Lenders shall be exercised by the Agent upon the request or instructions of the Majority Lenders. The Agent shall not incur any liability to the Lenders under or in respect of any of the Loan Documents with respect to anything which it may do or refrain from doing in the reasonable exercise of its judgment or which may seem to it to be necessary or desirable in the circumstances, except for its gross negligence or wilful misconduct. The Agent shall in all cases be fully protected in acting or refraining from acting under any of the Loan Documents in accordance with the instructions of the Majority Lenders and any action taken or failure to act pursuant to such instructions shall be binding on all Lenders. In respect of any notice by or action taken by the Agent hereunder, the Obligors shall at no time be obliged to enquire as to the right or authority of the Agent to so notify or act.

14.8 Notice of Events of Default. In the event that the Agent shall acquire actual knowledge or shall have been notified of any Default or Event of Default, the Agent shall promptly notify the Lenders and shall take such action and assert such rights under Section 13.1 of this Agreement and under the other Loan Documents as the Majority Lenders shall request in writing and the Agent shall not be subject to any liability by reason of its acting pursuant to any such request. If the Majority Lenders shall fail for five Business Days after receipt of the notice of any Default or Event of Default to request the Agent to take such action or to assert such rights under any of the Loan Documents in respect of such Default or Event of Default, the Agent may, but shall not be required to, and subject to subsequent specific instructions from the Majority Lenders, take such action or assert such rights (other than rights under Section 13.1 of this Agreement or under the other Loan Documents and other than giving an express waiver of any Default or any Event of Default) as it deems in its discretion to be advisable for the protection of the Lenders except that, if the Majority Lenders have instructed the Agent not to

take such action or assert such rights, in no event shall the Agent act contrary to such instructions unless required by Law to do so.

14.9 Responsibility Disclaimed. The Agent shall be under no liability or responsibility whatsoever as agent hereunder or under any of the other Loan Documents:

(a) to any Obligor or any other Person as a consequence of any failure or delay in the performance by, or any breach by, any Lender or Lenders of any of its or their obligations under any of the Loan Documents;

(b) to any Lender or Lenders as a consequence of any failure or delay in performance by, or any breach by, any Obligor or any other Person of any of its obligations under any of the Loan Documents; or

(c) to any Lender or Lenders for any statements, representations or warranties in any of the Loan Documents or in any other documents contemplated hereby or thereby or in any other information provided pursuant to any of the Loan Documents or any other documents contemplated hereby or thereby or for the validity, effectiveness, enforceability or sufficiency of any of the Loan Documents or any other document contemplated hereby or thereby.

14.10 Indemnification. The Lenders agree to indemnify the Agent (to the extent not reimbursed by the Obligors) *pro rata* according to the Pro Rata Share of each of them from and against any and all liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any nature whatsoever which may be imposed on, incurred by or asserted against the Agent in any way relating to or arising out of any of the Loan Documents or any other document contemplated hereby or thereby or any action taken or omitted by the Agent under any of the Loan Documents or any document contemplated hereby or thereby, except that no Lender shall be liable to the Agent for any portion of such liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements resulting from the gross negligence or wilful misconduct of the Agent.

14.11 Credit Decision. Each Lender represents and warrants to the Agent that:

(a) in making its decision to enter into this Agreement and to extend credit to the Borrowers under the Credit Facility, it is independently taking whatever steps it considers necessary to evaluate the financial condition and affairs of the Obligors and that it has made an independent credit judgment without reliance upon any information furnished by the Agent; and

(b) so long as any portion of the Credit Facility is being utilized by any Borrower, it will continue to make its own independent evaluation of the financial condition and affairs of the Obligors.

14.12 Successor Agent. Subject to the appointment and acceptance of a successor Agent as provided below, the Agent may resign at any time by giving 30 days' written notice thereof to the Lenders. Upon any such resignation, the Majority Lenders shall have the right to appoint a successor Agent who shall (provided no Event of Default has occurred and is

continuing) be approved by the Borrowers and shall be one of the Lenders unless none of the Lenders wishes to accept such appointment. If no successor Agent shall have been so appointed and shall have accepted such appointment by the time of such resignation, then the retiring Agent may, on behalf of the Lenders, appoint a successor Agent which shall be a bank organized under the Laws of Canada which has shareholders' equity in excess of $500,000,000 and has an office in Toronto. Upon the acceptance of any appointment as Agent hereunder by a successor Agent, such successor Agent shall thereupon succeed to and become vested with all the rights, powers, privileges, duties and obligations of the retiring Agent (in its capacity as Agent but not in its capacity as a Lender) and the retiring Agent shall be discharged from its duties and obligations hereunder (in its capacity as Agent but not in its capacity as a Lender). After any retiring Agent's resignation or removal hereunder as the Agent, provisions of this Article 14 shall continue in effect for its benefit in respect of any actions taken or omitted to be taken by it while it was acting as the Agent.

14.13 Delegation by Agent. With the prior approval of the Majority Lenders, the Agent shall have the right to delegate any of its duties or obligations hereunder as Agent to any Affiliate of the Agent so long as the Agent shall not thereby be relieved of such duties or obligations.

14.14 Waivers and Amendments

(a) Subject to Section 14.14(b), any term, covenant or condition of any of the Loan Documents may only be amended with the consent of the Obligors and the Majority Lenders or compliance therewith may be waived (either generally or in a particular instance and either retroactively or prospectively) by the Majority Lenders and in any such event the failure to observe, perform or discharge any such covenant, condition or obligation, so amended or waived (whether such amendment is executed or such consent or waiver is given before or after such failure), shall not be construed as a breach of such covenant, condition or obligation or as a Default or Event of Default. Any indulgence by the Lenders or the Majority Lenders with respect to any failure to strictly observe, perform or comply with any term, covenant or condition of any Loan Document is not a waiver of the entire term, covenant or condition or any subsequent default.

(b) Notwithstanding Section 14.14(a), without the prior written consent of each Lender, no such amendment or waiver shall directly:

(i) increase the amount of the Credit Facility;

(ii) alter the terms of Section 2.5 or Article 9;

(iii) extend the time of the Maturity Date or for any other payment of the interest or principal on any Loans, extend the time for payment with respect to any Bankers' Acceptances pursuant to Section 9.4, forgive any portion of interest or principal thereof, reduce the stated rate of interest thereon or amend the requirement of *pro rata* application of all amounts received by the Agent;

(iv) consent to any assignment by any Obligor of the Loan Documents or the benefit thereof;

(v) change the percentage of the Lenders required to constitute the Majority Lenders or otherwise amend the definition of Majority Lenders;

(vi) reduce the stated amount of any fees to be paid to the Lenders pursuant to Article 7 of this Agreement;

(vii) permit any subordination or postponement of the Loan Obligations; or

(viii) alter the terms of this Section 14.14(b).

(c) Without the prior written consent of the Agent, no amendment to or waiver of Sections 14.1 through 14.13 or any other provision hereof to the extent it affects the rights or obligations of the Agent or the Fronting Lender shall be effective.

(d) No amendment to or waiver of any provision hereof to the extent it affects the rights or obligations of any Lender which is a Fronting Lender at the time of such amendment or waiver shall be effective without the prior written consent of such party.

14.15 Determination by Agent Conclusive and Binding. Any determination to be made by the Agent on behalf of or with the approval of the Lenders or the Majority Lenders under this Agreement shall be made by the Agent in good faith and, if so made, shall be binding on all parties, absent manifest error.

14.16 Adjustments among Lenders after Acceleration.

(a) The Lenders agree that, at any time after all indebtedness of the Borrowers to the Lenders and the Agent pursuant hereto has become immediately due and payable pursuant to Section 13.1 or after the cancellation or termination of the Credit Facility, they will at any time or from time to time upon the request of any Lender through the Agent purchase portions of the availments made available by the other Lenders which remain outstanding, and make any other adjustments which may be necessary or appropriate, in order that the amounts of the availments made available by the respective Lenders which remain outstanding, as adjusted pursuant to this Section 14.16, will be in the same proportions as their respective Pro Rata Shares thereof immediately prior to such acceleration, cancellation or termination.

(b) The Lenders agree that, at any time after all indebtedness of the Borrowers to the Lenders and the Agent pursuant hereto has become immediately due and payable pursuant to Section 13.1 or after the cancellation or termination of the Credit Facility, the amount of any repayment made by any Borrower under this Agreement, and the amount of any proceeds from the exercise of any rights or remedies of the Lenders under the Loan Documents, which are to be applied against amounts owing hereunder as principal, will be so applied in a manner such

that to the extent possible, the availments made available by the respective Lenders which remain outstanding, after giving effect to such application, will be in the same proportions as their respective Pro Rata Shares thereof immediately prior to such acceleration, cancellation or termination.

(c) For greater certainty, the Lenders acknowledge and agree that, without limiting the generality of the provisions of Sections 14.16(a) and (b), such provisions will have application if and whenever any Lender shall obtain any payment (whether voluntary, involuntary, through the exercise of any right of set-off, compensation, or otherwise) on account of any monies owing or payable by any Borrower to it hereunder in excess of its *pro rata* share of payments on account of monies owing by such Borrower to all the Lenders hereunder.

(d) Each Borrower agrees to be bound by and to do all things necessary or appropriate to give effect to any and all purchases and other adjustments made by and between the Lenders pursuant to this Section 14.16.

14.17 Redistribution of Payment. If a Lender shall receive payment of a portion of the aggregate amount of principal and interest due to it hereunder which is greater than the proportion received by any other Lender in respect of the aggregate amount of principal and interest due in respect of the Credit Facility (having regard to the respective Individual Commitments of the Lenders), the Lender receiving such proportionately greater payment shall purchase a participation (which shall be deemed to have been done simultaneously with receipt of such payment) in that portion of the aggregate outstanding credit of the other Lender or Lenders so that the respective receipts shall be *pro rata* to their respective participation in the credits; provided, however, that if all or part of such proportionately greater payment received by such purchasing Lender shall be recovered from any Borrower, such purchase shall be rescinded and the purchase price paid for such participation shall be returned by such selling Lender or Lenders to the extent of such recovery, but without interest.

14.18 Distribution of Notices. With respect to each notice which is delivered to the Agent hereunder on behalf of certain of or all of the Lenders, the Agent shall provide a copy of such notice to each of such Lenders on the date it is received by the Agent if such date is a Business Day and it is received by the Agent prior to 12:00 noon (Toronto time) on such date; otherwise, the Agent shall provide a copy of such notice to each of such Lenders within one Business Day of receipt by the Agent. The foregoing sentence shall also apply to any automatic conversion pursuant to Section 6.4 or 6.5. With respect to each other document which is delivered to the Agent hereunder on behalf of certain of or all of the Lenders, the Agent shall provide a copy of such document to each of such Lenders within one Business Day of receipt by the Agent.

ARTICLE 15
GUARANTEE

15.1 Guarantee. The Guarantor hereby unconditionally, absolutely and irrevocably guarantees the full and punctual payment to the Agent as and when due, whether at stated maturity, by required prepayment, declaration, acceleration, demand or otherwise, of all of the

Loan Obligations of the Borrowers in the same currency (the "Designated Currency") as the currency of the Loan Obligations of the Borrowers, whether for principal, interest, fees, expenses, indemnities or otherwise.

15.2 Nature of Guarantee. This guarantee shall in all respects be a continuing, absolute, unconditional and irrevocable guarantee of payment when due and not of collection, and shall remain in full force and effect until all Loan Obligations have been paid in full and the commitments of the Lenders hereunder have been permanently terminated. For certainty, notwithstanding the repayment in full of all Indebtedness for Borrowed Money of the Borrowers owing under this Agreement, the termination of the Credit Facility and any release of the Borrowers of their obligations hereunder, this Article 15 shall survive until all Loan Obligations under all Loan Documents have been repaid in full and satisfied. The Guarantor guarantees that the Loan Obligations of the Borrowers will be paid strictly in accordance with their respective terms, regardless of any law, regulation or order now or hereafter in effect in any jurisdiction affecting any of such terms or the rights of the Lender with respect thereto.

15.3 Liability Not Lessened or Limited. Subject to the provisions hereof, the liability of the Guarantor under this guarantee shall be absolute, unconditional and irrevocable irrespective of, and without being lessened or limited by:

(a) any lack of validity, legality, effectiveness or enforceability of any of the agreements or instruments evidencing any of the Loan Obligations of any Borrower;

(b) the failure of the Lender:

(i) to assert any claim or demand or to enforce any right or remedy against any Borrower or any other Person (including any other guarantor) under the provisions of any of the agreements or instruments evidencing any of the Loan Obligations of any Borrower, or otherwise, or

(ii) to exercise any right or remedy against any other guarantor of, or collateral securing, any of the Loan Obligations of any Borrower;

(c) any change in the time, manner or place of payment of, or in any other term of, all or any of the Loan Obligations of any Borrower, or any other extension, compromise, indulgence or renewal of any Loan Obligations of any Borrower;

(d) any reduction, limitation, variation, impairment, discontinuance or termination of the Loan Obligations of any Borrower for any reason (other than by reason of any payment which is not required to be rescinded), including any claim of waiver, release, discharge, surrender, alteration or compromise, and shall not be subject to (and the Guarantor hereby waives any right to or claim of) any defence or setoff, counterclaim, recoupment or termination whatsoever by reason of the invalidity, illegality, nongenuineness, irregularity, compromise, unenforceability of, or any other event or occurrence affecting, the Loan Obligations of any Borrower or otherwise (other than by reason of any payment which is not required to be rescinded);

(e) any amendment to, rescission, waiver or other modification of, or any consent to any departure from, any of the terms of any of the agreements or instruments evidencing any of the Loan Obligations of any Borrower or any other guarantees or security;

(f) any addition, exchange, release, discharge, renewal, realization or non-perfection of any collateral security for the Loan Obligations of any Borrower or any amendment to, or waiver or release or addition of, or consent to departure from, any other guarantee held by the Agent for the benefit of the Lenders as security for any of the Loan Obligations of any Borrower;

(g) the loss of or in respect of or the unenforceability of any other guarantee or other security which the Agent or any Lender may now or hereafter hold in respect of the Loan Obligations of any Obligor, whether occasioned by the fault of the Agent or any Lender or otherwise;

(h) any change in the name of any Obligor, the articles of incorporation, capital structure, capacity or constitution of any Obligor, the bankruptcy or insolvency of any Obligor, the sale of any or all of the business or assets of any Obligor, or any Obligor being consolidated, merged or amalgamated with any other Person;

(i) any payment received on account of the Loan Obligations of any Borrower by the Agent or any Lender that it is obliged to repay pursuant to any Applicable Law or for any other reason; or

(j) any other circumstance which might otherwise constitute a defence available to, or a legal or equitable discharge of, any Obligor, any surety or any guarantor other than payment of any Loan Obligation.

15.4 Agent not Bound to Exhaust Recourse. Neither the Agent nor any Lender shall be bound to pursue or exhaust its recourse against any particular Borrower or others or any security or other guarantees it may at any time hold before being entitled to payment hereunder from the Guarantor to enforce its rights against the Guarantor under the Loan Documents to which the Guarantor is a party.

15.5 Enforcement. Upon any of the Loan Obligations of any Borrower becoming due and payable, the Guarantor shall forthwith pay to the Agent, within two Business Days of demand therefor, for the rateable benefit of the Lenders in immediately available funds at the address of the Agent set forth on its signature page hereto, the total amount of such Loan Obligations of such Borrower and the Agent shall apply the sums so paid and realized in such manner as provided for in this agreement. A written statement of the Agent or any Lender as to the amount of the Loan Obligations of a Borrower remaining unpaid to the Agent or any Lender at any time shall be *prima facie* evidence against the Guarantor, absent manifest error, as to the amount of the Loan Obligations of such Borrower remaining unpaid to the Lender at such time.

15.6 Guarantee in Addition to Other Security. The guarantee contained herein shall be in addition to and not in substitution for any other guarantee or other security which the Agent or any Lender may now or hereafter hold in respect of the Loan Obligations of the Borrowers,

and neither the Agent nor any Lender shall be under obligation to marshal in favour of the Guarantor any other guarantee or other security or any moneys or other assets which the Agent or any Lender may be entitled to receive or may have a claim upon.

15.7 Reinstatement. The guarantee contained herein and all other terms of this agreement shall continue to be effective or shall be reinstated, as the case may be, if at any time any payment (in whole or in part) of any of the Loan Obligations of any Borrower is rescinded or must otherwise be returned or restored by the Agent or any Lender by reason of the insolvency, bankruptcy or reorganization of such Borrower or for any other reason not involving the wilful misconduct of the Agent, all as though such payment had not been made.

15.8 Waiver of Notice, etc. The Guarantor hereby waives promptness, diligence, notice of acceptance and any other notice with respect to any of the Loan Obligations of the Borrowers and this Agreement, other than written demand for payment.

15.9 Subrogation Rights. Except to the extent necessary to preserve its rights, the Guarantor will not exercise any rights which it may acquire by way of subrogation under this agreement, by any payment made hereunder or otherwise, until the prior satisfaction in full of all of the Loan Obligations of the relevant Borrower. Any amount paid to the Guarantor on account of any such subrogation rights prior to the satisfaction in full of all Loan Obligations of the relevant Borrower shall be held in trust for the benefit of the Agent and shall immediately be paid to the Agent for the rateable benefit of the Lender and credited and applied against the Loan Obligations of the relevant Borrower, whether matured or unmatured; provided, however, that if

(a) the Guarantor has made payment to the Agent or any Lender of all or any part of the Loan Obligations of such Borrower, and

(b) all Loan Obligations of such Borrower (other than those provisions which by their terms survive the termination of relevant Loan Document) have been paid in full and all commitments have been permanently terminated,

the Agent agrees that, at the Guarantor's request, the Agent will execute and deliver to the Guarantor appropriate documents (without recourse and without representation or warranty) necessary to evidence the transfer by subrogation to the Guarantor of an interest in the Loan Obligations of the relevant Borrower resulting from such payment by the Guarantor. In furtherance of the foregoing, until the time upon which the Loan Obligations of the Borrowers have terminated, the Guarantor shall postpone any and all claims it may have against any Borrower to the claims of the Agent and the Lenders against the Borrowers hereunder and shall refrain from taking any action or commencing any proceeding against any Borrower (or its successors or assigns, whether in connection with a bankruptcy proceeding or otherwise) to recover any amounts in respect of payments made hereunder to the Agent. In the event any payments are made by the Guarantor in contravention of the preceding sentence, the Guarantor shall hold such payments in trust for the Agent and shall forthwith pay such payments to the Agent.

15.10 Advances After Certain Events. All advances, renewals and credits made or granted by the Lenders to or for any Borrower under the Loan Documents after the bankruptcy or insolvency of such Borrower, but before the Agent has received notice thereof, shall be deemed to form part of the Loan Obligations of such Borrower, and all advances, renewals and credits obtained from any Lender by or on behalf of such Borrower under the Loan Documents shall be deemed to form part of the Loan Obligations of such Borrower, notwithstanding any lack or limitation of power, incapacity or disability of such Borrower or of the directors or agents thereof and notwithstanding that of such Borrower may not be a legal entity and notwithstanding any irregularity, defect or informality in the obtaining of such advances, renewals or credits, whether or not the Agent has knowledge thereof.

15.11 Indemnity. The Guarantor hereby agrees to indemnify and save the Agent and the Lenders harmless from and against all loss, cost, damage, expense, claims and liability which it may at any time suffer or incur in connection with:

(a) any failure by any Borrower to duly and punctually pay or perform its Loan Obligations; and

(b) any loss for any reason whatsoever, including by operation of law or otherwise, of any right of the Agent or any Lender against the Borrowers in connection with the Loan Documents.

ARTICLE 16
MISCELLANEOUS

16.1 Waivers. No failure or delay by the Agent, the Lenders or the Majority Lenders in exercising any remedy, right or power hereunder or otherwise shall operate as a waiver thereof, except a waiver which is specifically given in writing by the Agent, and no single or partial exercise of any power, right or privilege hereunder will preclude any other or further exercise thereof or the exercise of any other power, right or privilege.

16.2 Notices. All notices, demands and other communications provided for in this Agreement shall be in writing and shall be personally delivered to an officer or other responsible employee of the addressee or sent by facsimile, charges prepaid, at or to the applicable addresses or facsimile numbers, as the case may be, set opposite the party's name on the signature page hereof (in the case of an Obligor or the Agent) or set forth in Schedule A hereto (in the case of the Lenders) or at or to such other address or addresses or facsimile number or numbers as any party hereto may from time to time designate to the other parties in such manner. Any communication which is personally delivered as aforesaid shall be deemed to have been validly and effectively given on the date of such delivery if such date is a Business Day and such delivery was made before 4:00 p.m. (Toronto time); otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of delivery. Any communication which is transmitted by facsimile as aforesaid shall be deemed to have been validly and effectively given on the date of transmission if such date is a Business Day and such transmission was made before 4:00 p.m. (Toronto time); otherwise, it shall be deemed to have been validly and effectively given on the Business Day next following such date of transmission.

16.3 Severability. Any provision hereof which is prohibited or unenforceable shall be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof.

16.4 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument.

16.5 Successors and Assigns. This Agreement shall enure to the benefit of and shall be binding upon the parties hereto and their respective successors and permitted assigns.

16.6 Assignment

(a) Neither the Loan Documents nor the benefit thereof may be assigned by any Obligor.

(b) A Lender may at any time sell to one or more other Persons ("**Participants**") participating interests in any credit outstanding hereunder, the commitment of the Lender hereunder or any other interest of the Lender under the Loan Documents provided such sale of a participating interest would not cause any Borrower to incur additional costs pursuant to Article 8. For greater certainty, the aforesaid proviso shall only be applicable for so long as no Event of Default has occurred and is continuing. In the event of any such sale by the Lender of a participating interest to a Participant, the Lender's obligations under this Agreement to the Borrowers shall remain unchanged, the Lender shall remain solely responsible for the performance thereof and the Borrowers shall continue to be obligated to the Lender in connection with the Lender's rights under this Agreement. Each Borrower agrees that each Participant shall be entitled to the benefits of Article 8 with respect to its participation hereunder; provided that no Participant shall be entitled to receive any greater amount pursuant to such Article than the Lender would have been entitled to receive in respect of the amount of the participation transferred by the Lender to such Participant had no such transfer occurred.

(c) With the written consent of the Borrowers and the Guarantor (which consent shall not be required (x) in circumstances where an Event of Default has occurred and is continuing (y) if such sale is to one or more other Lenders or to an Affiliate or Subsidiary of any of the Lenders and, in each case, a notice of the sale has been given to the Borrowers and the Guarantor) and the Agent, a Lender may at any time sell all or any part of its rights and obligations under the Loan Documents to one or more Persons ("**Purchasing Lenders**"), provided (prior to the occurrence and continuance of an Event of Default) such sale would not cause any Borrower to incur any additional costs pursuant to Article 8 and provided further (prior to the occurrence and continuance of an Event of Default) any partial assignment or sale shall be with respect to a minimum Individual Commitment of $10,000,000 and in integral multiples of $1,000,000 in excess thereof or such lesser amount as will result in each of the selling Lender (except if the selling Lender is assigning its entire Individual Commitment) and the Purchasing Lender having a minimum

aggregate Individual Commitment of $10,000,000. As concerns any assignment where the written consent of the Borrowers and the Guarantor is not required, the Agent shall provide notice to the Borrowers and the Guarantor of such assignment; provided, however, failure to provide such notice shall in no way effect the validity of such assignment. Provided an Event of Default has not occurred and is not continuing, a Purchasing Lender shall be a Canadian Qualified Lender unless such Purchasing Lender has waived its rights to the benefit of Section 8.6 and such waiver is otherwise in form and substance satisfactory to the Borrowers. Upon such sale, the Lender shall, to the extent of such sale, be released from its obligations under the Loan Documents and each of the Purchasing Lenders shall become a party to the Loan Documents to the extent of the interest so purchased. Any such assignment by a Lender shall not be effective unless and until such Lender has paid to the Agent an assignment fee in the amount of $3,500 for each Purchasing Lender (unless the payment of such fee has been waived by the Agent), unless and until the assignee has executed an instrument substantially in the form of Schedule C hereto or otherwise in a form acceptable to such Lender, the Purchasing Lender and the Agent, whereby such assignee has agreed to be bound by the terms of the Loan Documents as a Lender and has agreed to a specific Individual Commitment and a specific address and facsimile number for the purpose of notices as provided in Section 16.2 and unless and until a copy of a fully executed copy of such instrument has been consented to by the Agent and, if no Event of Default has occurred and is continuing, consented to by the Borrowers. Upon any such assignment becoming effective, Schedule A hereto shall be deemed to be amended to include the assignee as a Lender with the specific Individual Commitment, address and facsimile number as aforesaid and the Individual Commitment of the Lender making such assignment shall be deemed to be reduced by the amount of the Individual Commitment of the assignee. Where any such assignment occurs after the occurrence and during the continuance of an Event of Default, the Purchasing Lender, if it is not a Canadian Qualified Lender, shall make reasonable efforts to respond accurately and promptly to a question in writing of the Borrower as to the Purchasing Lender's country of residence.

(d) Each Obligor authorizes the Agent and the Lenders to disclose to any Participant or Purchasing Lender (each, a "**Transferee**") and any prospective Transferee any and all financial and other information in its possession concerning such Obligor which has been delivered to them by or on behalf of the Borrower pursuant to this Agreement or which has been delivered to them by or on behalf of such Obligor in connection with their credit evaluation of such Obligor prior to entering into this Agreement, so long as any such Transferee or prospective Transferee agrees not to disclose any confidential, non-public information to any Person other than its non-brokerage Affiliates, employees, accountants or legal counsel, unless required by Law and after prior notice to such Obligor.

16.7 Entire Agreement. The Loan Documents and the agreements referred to therein and delivered pursuant thereto constitute the entire agreement between the parties hereto and

supersede any prior agreements, commitment letters, undertakings, declarations, representations and understandings, both written and verbal, in respect of the subject matter hereof.

16.8 Further Assurances. Each Obligor shall from time to time and at all times hereafter, upon every reasonable request of the Agent, make, do, execute, and deliver or cause to be made, done, executed and delivered all such further acts, deeds, assurances and things as may be necessary in the opinion of the Agent for more effectually implementing and carrying out the true intent and meaning of this Agreement, the other Loan Documents or any agreement delivered pursuant hereto or thereto.

16.9 Judgment Currency

(a) If, for the purpose of obtaining or enforcing judgment against any Obligor in any court in any jurisdiction, it becomes necessary to convert into a particular currency (such currency being hereinafter in this Section 16.9 referred to as the "**Judgment Currency**") an amount due in another currency (such other currency being hereinafter in this Section 16.9 referred to as the "**Indebtedness Currency**") under this Agreement, the conversion shall be made at the rate of exchange prevailing on the Business Day immediately preceding:

(i) the date of actual payment of the amount due, in the case of any proceeding in the courts of the Province of Ontario or in the courts of any other jurisdiction that will give effect to such conversion being made on such date; or

(ii) the date on which the judgment is given, in the case of any proceeding in the courts of any other jurisdiction (the date as of which such conversion is made pursuant to this Section 16.9(a)(ii) being hereinafter in this Section 16.9 referred to as the "**Judgment Conversion Date**").

(b) If, in the case of any proceeding in the court of any jurisdiction referred to in Section 16.9(a)(ii), there is a change in the rate of exchange prevailing between the Judgment Conversion Date and the date of actual payment of the amount due, the Borrower shall pay to the Lenders such additional amount (if any, but in any event not a lesser amount) as may be necessary to ensure that the amount paid in the Judgment Currency, when converted at the rate of exchange prevailing on the date of payment, will produce the amount of the Indebtedness Currency which could have been purchased with the amount of Judgment Currency stipulated in the judgment or judicial order at the rate of exchange prevailing on the Judgment Conversion Date.

(c) Any amount due from any Obligor under the provisions of Section 16.9(b) shall be due to the judgment creditor as a separate debt and shall not be affected by judgment being obtained for any other amounts due under or in respect of this Agreement.

(d) The term "**rate of exchange**" in this Section 16.9 means the noon spot rate of exchange for Canadian interbank transactions applied in converting the Indebtedness Currency into the Judgment Currency published by the Bank of Canada for the day in question.

IN WITNESS WHEREOF the parties hereto have executed this Agreement.

CANADIAN NIAGARA POWER INC.
P.O. Box 1218
1130 Bertie Street
Fort Erie, ON L2A 5Y2
Attention: Chief Financial Officer
Telefax: (905) 871-8676

CANADIAN NIAGARA POWER INC.

By: _____
Name: GLEN KING
Title: VP, FINANCE + CFO

By: _____
Name: R. Scott Hounkes
Title: Vice President Corp. Services + General Counsel

CORNWALL STREET RAILWAY, LIGHT AND POWER COMPANY LIMITED
P.O. Box 1218
1130 Bertie Street
Fort Erie, ON L2A 5Y2
Attention: Chief Financial Officer
Telefax: (905) 871-8676

CORNWALL STREET RAILWAY, LIGHT AND POWER COMPANY LIMITED

By: _____
Name: GLEN KING
Title: VP, FINANCE + CFO

By: _____
Name: R. Scott Hounkes
Title: Vice President Corp - Services + General Counsel

ALGOMA POWER INC.
P.O. Box 1218
1130 Bertie Street
Fort Erie, ON L2A 5Y2
Attention: Chief Financial Officer
Telefax: (905) 871-8676

ALGOMA POWER INC.

By: _____
Name: GLEN KING
Title: VP, FINANCE + CFO

By: _____
Name: R. Scott Hounkes
Title: Vice President Corporate Services + General Counsel

FORTISONTARIO INC.
P.O. Box 1218
1130 Bertie Street
Fort Erie, ON L2A 5Y2

Attention: Chief Financial Officer
Telefax: (905) 871-8676

FORTISONTARIO INC.

By: _____
Name: GLEN KING
Title: VP, FINANCE & CFO

By: _____
Name: R. Scott Hawkes
Title: Vice President Corporate Services & General Counsel

THE BANK OF NOVA SCOTIA
Corporate Banking – Loan Syndications
40 King Street West, 62nd Floor
Toronto, Ontario M5W 2X6

Attention: Managing Director
Telefax: (416) 866-3329

THE BANK OF NOVA SCOTIA, as Agent

By: _____
Name: Robert Boomhour
Title: Director

By: _____
Name: Clement Yu
Title: Associate

THE BANK OF NOVA SCOTIA, as Lender

By: _____
Name: Bradley Walker
Title: Director

By: _____
Name: Rob Bridge
Title: Associate

SCHEDULE A
INDIVIDUAL COMMITMENTS

Name and Address of Lender	Individual Commitment
The Bank of Nova Scotia Corporate Banking – Power & Utilities 40 King Street West, 62nd Floor Toronto, Ontario M5W 2X6 Attention: Managing Director Telefax: (416) 933-7399	$30,000,000

SCHEDULE B
COMPLIANCE CERTIFICATE

TO: THE BANK OF NOVA SCOTIA, as Agent

I, _____, the Chief Financial Officer of **[Canadian Niagara Power Inc./Cornwall Street Railway, Light and Power Company Limited/Algoma Power Inc.]** (the "**Relevant Borrower**"), in such capacity and not personally, hereby certify that:

2. I am the duly appointed Chief Financial Officer of the Relevant Borrower referred to and defined therein in the Credit Agreement dated as of June 11, 2012 between the Borrowers, FortisOntario Inc., as guarantor, the lending institutions from time to time parties thereto as Lenders and The Bank of Nova Scotia, as administrative agent of the Lenders, as the same may be amended, modified, supplemented or replaced from time to time (the "**Credit Agreement**") and as such I am providing this certificate for and on behalf of the Borrower pursuant to the Credit Agreement.

3. I am familiar with and have examined the provisions of the Credit Agreement including, without limitation, those of Articles 10, 11 and 13 thereof.

4. To the best of my knowledge, information and belief and after due inquiry, no Default has occurred and is continuing as at the date hereof **[or, if such a Default has occurred with respect to the Relevant Borrower specifying such Default and the steps being taken to remedy same]**.

5. As of the last day of the Fiscal Quarter ending _____, the Debt to Capitalization Ratio of the Relevant Borrower as referred to in Section 11.1(j) of the Credit Agreement was _____, the detailed calculations of which are attached hereto.

6. Unless the context otherwise requires, capitalized terms in the Credit Agreement which appear herein without definitions shall have the meanings ascribed thereto in the Credit Agreement.

DATED this _____ day of _____, _____.

_____
[Name]
Chief Financial Officer

SCHEDULE C
FORM OF ASSIGNMENT

Dated: _____

Reference is made to the Credit Agreement dated as of June 11, 2012 (the "**Credit Agreement**"), between Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company Limited and Algoma Power Inc., as borrowers, FortisOntario Inc., as guarantor, the lending institutions from time to time parties thereto as Lenders and The Bank of Nova Scotia, as administrative agent of the Lenders, as amended to the date hereof. Terms defined in the Credit Agreement are used herein as therein defined.

_____ (the "**Assignor**") and _____ (the "**Assignee**") agree as follows:

1. The Assignor hereby sells and assigns to the Assignee, and the Assignee hereby purchases and assumes from the Assignor, a _____% interest in and to all of the Assignor's rights and obligations as a Lender under the Loan Documents as of the Effective Date (as defined below) (including, without limitation, such percentage interest in the Assignor's Individual Commitment as in effect on the Effective Date and the credit extended by the Assignor and outstanding on the Effective Date).

2. The Assignor (i) represents and warrants that as of the date hereof its Individual Commitment is $_____ (without giving effect to assignments thereof which have not yet become effective, including, but not limited to, the assignment contemplated hereby), and the aggregate outstanding amount of credit extended by it is $_____ (without giving effect to assignments thereof which have not yet become effective, including, but not limited to, the assignment contemplated hereby); (ii) represents and warrants that it is the legal and beneficial owner of the interest being assigned by it hereunder and that such interest is free and clear of any adverse claim; (iii) makes no representation or warranty and assumes no responsibility with respect to any statements, warranties or representations made in or in connection with the Loan Documents or the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any other instrument or document furnished pursuant thereto; (iv) makes no representation or warranty and assumes no responsibility with respect to the financial condition of the Obligors or the performance or observance by any Obligor of any of its obligations under the Loan Documents or any other instrument or document furnished pursuant thereto; and (v) gives notice to the Agent of the assignment to the Assignee hereunder.

3. The effective date of this Assignment (the "**Effective Date**") shall be _____. Following the execution of this Assignment, it will be delivered to the Agent for its consent and, to the extent required pursuant to Section 16.6(c) of the Credit Agreement, to the Borrowers for their consent.

4. Upon such consent, as of the Effective Date (i) the Assignee shall, in addition to any rights and obligations under the Loan Documents held by it immediately prior to the

Effective Date, have the rights and obligations under the Loan Documents that have been assigned to it pursuant to this Assignment, (ii) the Assignor shall, to the extent provided in this Assignment, relinquish its rights and be released from its obligations under the Loan Documents (iii) the Individual Commitment of the Assignee shall be as described in Appendix 1 hereto and (iv) the address and facsimile number of the Assignee for the purposes of Schedule A to the Credit Agreement shall be as set forth in Appendix 1 hereto.

5. The Assignor and Assignee shall make all appropriate adjustments in payments under the Loan Documents for periods prior to the Effective Date directly between themselves.

6. This Assignment shall be governed by, and construed in accordance with, the Laws of the Province of Ontario and the Laws of Canada applicable therein.

[ASSIGNOR]

By: _____
Name:
Title:

[ASSIGNEE]

By: _____
Name:
Title:

Acknowledged and agreed to as of this _____ day of _____, _____.

THE BANK OF NOVA SCOTIA, as Agent

By: _____
Name:
Title:

By: _____
Name:
Title:

[1]Acknowledged and agreed to as of this_____ day of _____, _____.

CANADIAN NIAGARA POWER INC.

By: _____
Name:
Title:

By: _____
Name:
Title:

CORNWALL STREET RAILWAY, LIGHT AND POWER COMPANY LIMITED

By: _____
Name:
Title:

By: _____
Name:
Title:

ALGOMA POWER INC.

By: _____
Name:
Title:

By: _____
Name:
Title:

[1] Not applicable if Event of Default outstanding or if Lender assigning to another Lender or to an Affiliate or Subsidiary.

SCHEDULE D
FORM OF DRAWDOWN NOTICE

TO: The Bank of Nova Scotia, as Agent
Corporate Banking – Loan Syndications
40 King Street West, 62nd Floor
Toronto, Ontario M5W 2X6

Attention: Managing Director

Facsimile: (416) 866-3329

RE: **Credit Agreement dated as of June 11, 2012 (the "Credit Agreement") between Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company Limited and Algoma Power Inc., as borrowers, FortisOntario Inc., as guarantor, the lending institutions from time to time parties thereto as Lenders and The Bank of Nova Scotia, as administrative agent of the Lenders**

Pursuant to the terms of the Credit Agreement, the undersigned hereby irrevocably notifies you that it wishes to draw down under the Credit Facility on _____ as follows:

1. Availment Option: _____

2. Amount: _____

3. If Bankers' Acceptance, term: _____

4. If Letter, the information which is attached hereto and is required pursuant to Section 4.1(e) of the Credit Agreement.

[The undersigned hereby irrevocably authorizes and directs you to pay the proceeds of this drawdown to _____ at _____.]

The undersigned hereby confirms that no Default has occurred and is continuing as at the date hereof or would arise immediately after giving effect to or as a result of such drawdown.

All capitalized terms defined in the Credit Agreement and used herein shall have the meanings ascribed thereto in the Credit Agreement.

DATED the _____ day of _____, _____.

[RELEVANT BORROWER]

By: _____
Name:
Title:

By: _____
Name:
Title:

SCHEDULE E
FORM OF ROLLOVER NOTICE

TO: The Bank of Nova Scotia, as Agent
Corporate Banking – Loan Syndications
40 King Street West, 62nd Floor
Toronto, Ontario M5W 2X6

Attention: Managing Director

Facsimile: (416) 866-3329

RE: **Credit Agreement dated as of June 11, 2012 (the "Credit Agreement") between Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company Limited and Algoma Power Inc., as borrowers, FortisOntario Inc., as guarantor, the lending institutions from time to time parties thereto as Lenders and The Bank of Nova Scotia, as administrative agent of the Lenders**

Pursuant to the terms of the Credit Agreement, the undersigned hereby irrevocably requests a rollover of outstanding credit under the Credit Facility on _____ as follows:

Maturity date of maturing Bankers' Acceptances or BA Rate Loans	_____
Aggregate face amount of maturing Bankers' Acceptances or BA Rate Loans	$_____
Portion thereof to be replaced	$_____
Term of new Bankers' Acceptances (or BA Rate Loans)	_____

The undersigned hereby confirms that no Default has occurred and is continuing as at the date hereof or would arise immediately after giving effect to or as a result of such rollover.

All capitalized terms defined in the Credit Agreement and used herein shall have the meaning ascribed thereto in the Credit Agreement.

DATED the _____ day of _____, _____.

[RELEVANT BORROWER]

By: _____
Name:
Title:

By: _____
Name:
Title:

SCHEDULE F
FORM OF CONVERSION NOTICE

TO: The Bank of Nova Scotia, as Agent
Corporate Banking – Loan Syndications
40 King Street West, 62nd Floor
Toronto, Ontario M5W 2X6

Attention: Managing Director

Facsimile: (416) 866-3329

RE: **Credit Agreement dated as of June 11, 2012 (the "Credit Agreement") between Canadian Niagara Power Inc., Cornwall Street Railway, Light and Power Company Limited and Algoma Power Inc., as borrowers, FortisOntario Inc., as guarantor, the lending institutions from time to time parties thereto as Lenders and The Bank of Nova Scotia, as administrative agent of the Lenders**

Pursuant to the terms of the Credit Agreement, the undersigned hereby irrevocably requests a conversion of outstanding credit under the Credit Facility on _____ as follows:

[Choose as appropriate]

Converting From Bankers' Acceptances (or BA Rate Loan)		**Converting Into Bankers' Acceptances (or BA Rate Loan)**	
Maturity date of Bankers' Acceptances to be converted	_____	Aggregate face amount of new Bankers' Acceptances	$_____

Aggregate face amount of said Bankers' Acceptances	$_____	Term of new Bankers' Acceptances	_____
Portion thereof to be converted	$_____		
Converting from Prime Rate Loans		**Converting to Prime Rate Loans**	
Principal amount of Prime Rate Loan to be converted	$_____	Principal amount of new Prime Rate Loan	$_____
Portion thereof to be converted	$_____		

The undersigned hereby confirms that no Default has occurred and is continuing as at the date hereof or would arise immediately after giving effect to or as a result of such conversion.

All capitalized terms defined in the Credit Agreement and used herein shall have the meaning ascribed thereto in the Credit Agreement.

DATED the _____day of _____, _____ .

[RELEVANT BORROWER]

By: _____
Name:
Title:

By: _____
Name:
Title:

SCHEDULE G
INDEBTEDNESS FOR BORROWERED MONEY

Existing CIBC Indebtedness

1. $30,000,000 principal amount of 7.092% senior unsecured notes of CNPI due August 14, 2018

2. $22,000,000 principal amount of 7.092% senior unsecured notes of Cornwall due August 14, 2018

3. $52,000,000 principal amount of 5.118% senior unsecured notes of Algoma due December 16, 2041

Inter-Corporate Debt

4. CNPI owes FortisOntario $5m at 7.62% - promissory note

5. CNPI owes FortisOntario $15m at 6.13% - promissory note

6. FortisOntario owes Cornwall Electric $3.5m at 6.13% - promissory note

(OEB)

Capital Structure and Cost of Capital

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

49. Ref: E5/T1/S1/p.2 – Long-term debt

Please provide a copy of the $30 million third party senior unsecured note dated August 14, 2003. Please advise what, if any, related transactions occurred contemporaneously or as part of a series with the issuance of that indebtedness, whether involving the Applicant or any of its affiliates.

RESPONSE:

A copy of the Notes dated August 14, 2003 are attached.

The primary use of the proceeds from the $30 million debt issuance was the repayment of $27.4 million in affiliated debt owing to FortisOntario.

Congruent with the CNPI debt issuance of $30 million on August 15, 2003, Cornwall Electric also issued $22 million of debt on identical terms as CNPI.

CANADIAN NIAGARA POWER INC.

7.092 % Senior Unsecured Note Due August 14, 2018

No. 1 August 14, 2003

$18,000,000.00 PPN _____

FOR VALUE RECEIVED, the undersigned, Canadian Niagara Power Inc. (herein called the "Company"), a corporation incorporated and existing under the laws of Ontario, hereby promises to pay to **SUN LIFE ASSURANCE COMPANY OF CANADA**, or its registered assigns (the "Purchaser"), the principal sum of EIGHTEEN MILLION DOLLARS on August 14, 2018 (the "Maturity Date") with interest at a rate per annum of 7.092% calculated and payable semi-annually. Interest will be payable after as well as before the Maturity Date, default and judgment semi-annually on August 14 and February 14 in each year commencing on February 14, 2004 in accordance with the payment schedule set forth in Annex A hereto; provided that in the event of any redemption, the amounts payable pursuant to Annex A shall be reduced proportionately based on the amount redeemed and the original face amount of the Note.

Payments of principal, interest, any Redemption Price and other amounts owing with respect to this Note are to be made in lawful money of Canada at Toronto, Ontario, or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Unsecured Notes (herein called the "Notes") issued pursuant to the Master Note Purchase Agreement dated as of August 14, 2003 (as from time to time amended, the "Note Purchase Agreement"), among the Company, the Purchaser and the other Purchasers named therein and the Purchaser is entitled to the benefits thereof. The holder of this Note will be deemed, by its acceptance hereof, to have made the representation set forth in Section 9.1 of the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or counsel to such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default, as defined in the Note Purchase Agreement, occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in

manner, at the price (including any applicable Redemption Price) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of Ontario excluding choice-of-law principles of the law of such province that would require the application of the laws of a jurisdiction other than such province.

CANADIAN NIAGARA POWER INC.

by: _____
Name: Timothy D. Curtis
Title: V/ Finance & CFO

by: _____
Name: WILLIAM J. DALEY
Title: PRESIDENT & CEO

ANNEX A

Date	Dollars per $1,000,000 in principal amount
February 15, 2004	$35,460
August 14, 2004	$35,460
February 14, 2005	$35,460
August 14, 2005	$35,460
February 14, 2006	$35,460
August 14, 2006	$35,460
February 14, 2007	$35,460
August 14, 2007	$35,460
February 14, 2008	$35,460
August 14, 2008	$35,460
February 14, 2009	$35,460
August 14, 2009	$35,460
February 14, 2010	$35,460
August 14, 2010	$35,460
February 14, 2011	$35,460
August 14, 2011	$35,460
February 14, 2012	$35,460
August 14, 2012	$35,460
February 14, 2013	$35,460
August 14, 2013	$35,460
February 14, 2014	$35,460
August 14, 2014	$35,460

February 14, 2015	$35,460
August 14, 2015	$35,460
February 14, 2016	$35,460
August 14, 2016	$35,460
February 14, 2017	$35,460
August 14, 2017	$35,460
February 14, 2018	$35,460
August 14, 2018	$35,460

CANADIAN NIAGARA POWER INC.

7.092 % Senior Unsecured Note Due August 14, 2018

No. 2 August 14, 2003

$8,000,000.00 PPN _____

FOR VALUE RECEIVED, the undersigned, Canadian Niagara Power Inc. (herein called the "Company"), a corporation incorporated and existing under the laws of Ontario, hereby promises to pay to **CANADA LIFE FINANCIAL CORPORATION**, or its registered assigns (the "Purchaser"), the principal sum of EIGHT MILLION DOLLARS on August 14, 2018 (the "Maturity Date") with interest at a rate per annum of 7.092% calculated and payable semi-annually. Interest will be payable after as well as before the Maturity Date, default and judgment semi-annually on August 14 and February 14 in each year commencing on February 14, 2004 in accordance with the payment schedule set forth in Annex A hereto; provided that in the event of any redemption, the amounts payable pursuant to Annex A shall be reduced proportionately based on the amount redeemed and the original face amount of the Note.

Payments of principal, interest, any Redemption Price and other amounts owing with respect to this Note are to be made in lawful money of Canada at Toronto, Ontario, or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Unsecured Notes (herein called the "Notes") issued pursuant to the Master Note Purchase Agreement dated as of August 14, 2003 (as from time to time amended, the "Note Purchase Agreement"), among the Company, the Purchaser and the other Purchasers named therein and the Purchaser is entitled to the benefits thereof. The holder of this Note will be deemed, by its acceptance hereof, to have made the representation set forth in Section 9.1 of the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or counsel to such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default, as defined in the Note Purchase Agreement, occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in

manner, at the price (including any applicable Redemption Price) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of Ontario excluding choice-of-law principles of the law of such province that would require the application of the laws of a jurisdiction other than such province.

CANADIAN NIAGARA POWER INC.

by: _____
Name: Timothy S. Carter
Title: VP Finance + CFO

by: _____
Name: WILLIAM J. DALEY
Title: President + CEO

Date	Dollars per $1,000,000 in principal amount
February 15, 2004	$35,460
August 14, 2004	$35,460
February 14, 2005	$35,460
August 14, 2005	$35,460
February 14, 2006	$35,460
August 14, 2006	$35,460
February 14, 2007	$35,460
August 14, 2007	$35,460
February 14, 2008	$35,460
August 14, 2008	$35,460
February 14, 2009	$35,460
August 14, 2009	$35,460
February 14, 2010	$35,460
August 14, 2010	$35,460
February 14, 2011	$35,460
August 14, 2011	$35,460
February 14, 2012	$35,460
August 14, 2012	$35,460
February 14, 2013	$35,460
August 14, 2013	$35,460
February 14, 2014	$35,460
August 14, 2014	$35,460

February 14, 2015	$35,460
August 14, 2015	$35,460
February 14, 2016	$35,460
August 14, 2016	$35,460
February 14, 2017	$35,460
August 14, 2017	$35,460
February 14, 2018	$35,460
August 14, 2018	$35,460

7.092 % Senior Unsecured Note Due August 14, 2018

No. 3 August 14, 2003

$4,000,000.00 PPN _____

FOR VALUE RECEIVED, the undersigned, Canadian Niagara Power Inc. (herein called the "Company"), a corporation incorporated and existing under the laws of Ontario, hereby promises to pay to **MARITIME LIFE ASSURANCE COMPANY**, or its registered assigns (the "Purchaser"), the principal sum of FOUR MILLION DOLLARS on August 14, 2018 (the "Maturity Date") with interest at a rate per annum of 7.092% calculated and payable semi-annually. Interest will be payable after as well as before the Maturity Date, default and judgment semi-annually on August 14 and February 14 in each year commencing on February 14, 2004 in accordance with the payment schedule set forth in Annex A hereto; provided that in the event of any redemption, the amounts payable pursuant to Annex A shall be reduced proportionately based on the amount redeemed and the original face amount of the Note.

Payments of principal, interest, any Redemption Price and other amounts owing with respect to this Note are to be made in lawful money of Canada at Toronto, Ontario, or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Unsecured Notes (herein called the "Notes") issued pursuant to the Master Note Purchase Agreement dated as of August 14, 2003 (as from time to time amended, the "Note Purchase Agreement"), among the Company, the Purchaser and the other Purchasers named therein and the Purchaser is entitled to the benefits thereof. The holder of this Note will be deemed, by its acceptance hereof, to have made the representation set forth in Section 9.1 of the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or counsel to such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default, as defined in the Note Purchase Agreement, occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in

manner, at the price (including any applicable Redemption Price) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of Ontario excluding choice-of-law principles of the law of such province that would require the application of the laws of a jurisdiction other than such province.

CANADIAN NIAGARA POWER INC.

by: _____
Name: Timothy D. Curtis
Title: VP Finance & CFO

by: _____
Name: WILLIAM J. DALEY
Title: President & CEO

ANNEX A

Date	**Dollars per $1,000,000 in principal amount**
February 15, 2004	$35,460
August 14, 2004	$35,460
February 14, 2005	$35,460
August 14, 2005	$35,460
February 14, 2006	$35,460
August 14, 2006	$35,460
February 14, 2007	$35,460
August 14, 2007	$35,460
February 14, 2008	$35,460
August 14, 2008	$35,460
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August 14, 2010	$35,460
February 14, 2011	$35,460
August 14, 2011	$35,460
February 14, 2012	$35,460
August 14, 2012	$35,460
February 14, 2013	$35,460
August 14, 2013	$35,460
February 14, 2014	$35,460
August 14, 2014	$35,460

February 14, 2015	$35,460
August 14, 2015	$35,460
February 14, 2016	$35,460
August 14, 2016	$35,460
February 14, 2017	$35,460
August 14, 2017	$35,460
February 14, 2018	$35,460
August 14, 2018	$35,460

(OEB)

Capital Structure and Cost of Capital

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

50. Ref: E5/T1/S1/p.2; E5/T1/S4/p.1 & E5/T1/S5/p.1 – Promissory Note

Two of the debt instruments owned by CNPI are Promissory Notes due to Fortis Ontario its corporate parent. A copy of these Promissory Notes are provided in E5/T1/S4 and E5/T1/S5.

a) Each promissory note states that the existing note has no repayment terms but is callable by the parent company on demand. Can CNPI negotiate repayment with Fortis Ontario? Has it done so in the past? If so, what has (have) been the outcome(s)?
b) Please compare the existing debt rates of 6.13% ($15 million) and 7.62% ($5 million) to current market rates.

RESPONSE:

a) Both CNPI and FortisOntario have the same senior management team, thus CNPI can negotiate repayment with FortisOntario.

In 2003, when the $30 million third party debt was issued, CNPI repaid two outstanding promissory notes (attached) owing to its parent company. Those notes were callable by the lender similar to the existing notes.

b) The current market rates are impacted by both the long Canada bond rate and the market demand for a non-rated small issuance by a regulated electricity distribution company. CNPI has been recently advised by CIBC World Markets that the current all-in rate for 30-year debt would be

approximately 5%. Therefore, CNPI does not believe it can issue long-term debt for the deemed long-term debt rate.

CANCELLED

PROMISSORY NOTE

December 31, 2001

FOR VALUE RECEIVED, Canadian Niagara Power Inc., a corporation incorporated and validly existing under the laws of the Province of Ontario (hereinafter the "Borrower"), hereby promises to pay unconditionally to Canadian Niagara Power Company Limited, a corporation incorporated and validly existing under the laws of Ontario (hereinafter the "Lender") the amount of $24,820,810.98 by April 30, 2005 plus interest thereon for the date thereof on a quarterly basis at a rate of 7.1225% per annum.

Both principal amount and interest shall be payable in Canadian Dollars and in immediately available funds at the times specified above and place as the Lender shall specify.

This promissory note has been issued pursuant to the resolution of the board of Directors of the Borrower dated December 5, 2001. This promissory note replaces the promissory note issued July 21, 2000 in the amount of $14,820,810.98.

This promissory note shall be secured by a general security agreement executed by the Borrower in favour of the Lender, constituting a first-priority lien, subject to any priorities, guarantees, pledges or other securities granted to the Canadian Imperial Bank of Commerce, on the collateral thereunder.

In withness whereof, the borrower caused this Promissory note to be duly executed in its corporate name as of the 31st day of December, 2001, by two of its officers duly authorized.

Canadian Niagara Power Inc.

Timothy B. Curtis
Vice President, Finance
& Chief Financial Officer

Fred J. O'Brien
Vice President, Operations

Repaid on August 14, 2003 on closing of $30 million 7.092% Senior Unsecured Notes.

Canadian Niagara Power Inc.
1130 Bertie Street • P.O. Box 1218 • Fort Erie, Ontario L2A 5Y2
(905)871-0330
www.cnpower.com

PROMISSORY NOTE

$5,050,000

DATE: April 1, 2003

DUE: ON DEMAND

FOR VALUE RECEIVED Canadian Niagara Power Inc. ("CNPI") hereby promises to pay on demand to or to the order of FortisOntario Inc. ("FortisOntario") at1130 Bertie Street, P.O. Box 1218, Fort Erie, Ontario, the principal amount of $5,050,000 in lawful money of Canada and to pay interest both before and after default at the rate of eight percent (8%) per annum calculated semi-annually not in advance on the principal amount, said interest to be payable on May 31, August 31, November 30, and February 28 in each year commencing on the 31st day of May, 2003.

The principal amount outstanding under this promissory note from time to time and all accrued interest thereon shall become due and be paid in full upon demand being made by Fortis therefore.

CANCELLED

CNPI hereby waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit and diligence in taking any action.

This Promissory Note is given to secure payment of a loan from FortisOntario to CNPI for the funds borrowed by CNPI from FortisOntario to purchase the shares of Eastern Ontario Power Inc., formerly Granite Power Distribution Corporation on April 1, 2003 under the terms of an assignment and assumption agreement made as of the 1st day of April, 2003 between the undersigned as assignee and FortisOntarion as assignor.

DATED at Toronto, Ontario, as of this 1st day of April, 2003.

CANADIAN NIAGARA POWER INC.

Timothy B. Curtis
Vice President, Finance and Chief Financial Officer

Frederick J. O'Brien
Vice President, Operations

at July 31, 2003 and balance repaid on August 14, 200
on closing of $30 million private placement of 7.092% Senio
Unsecured Notes.

(EP)

5. Capital Structure and Cost of Capital

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

67. Ref: Exhibit 5, Tab 1, Schedule 1

a) Please confirm that the debt instruments in the amounts of $15 million and $5 million are from an affiliate and have a fixed interest rate for the term of the loans.

b) Please confirm that the loans noted above in part (a) are callable on demand. Please indicate if they are callable with a certain amount of notice. If so, please indicate the length of the notice.

c) Can CNPI call the above noted loans? If not, why not?

d) What is the penalty for early payment of the FortisOntario loans?

e) Has CNPI considered replacing the affiliate debt with third party debt at a lower rate? If not, why not?

RESPONSE:

a) The promissory notes are with CNPI's parent company, FortisOntario, and have a fixed interest rate.

b) The promissory notes are callable on demand by FortisOntario. Notice has not been specified in the promissory notes. The promissory notes are held by CNPI's parent company, FortisOntario.

c) Both CNPI and FortisOntario have the same senior management team, thus CNPI can negotiate repayment with FortisOntario.

d) There is no penalty for early payment.

e) Please see Board Staff interrogatory #50 b).

(SEC)

5. Capital Structure and Cost of Capital
5.1 Is the proposed capital structure, rate of return on equity, short-term and long-term debt rate appropriate?

19. [Ex.5/1/1/p.2]
Please provide a copy of all outstanding debt instruments.

RESPONSE:

Please see the responses to Board Staff Interrogatories #48 and #49.

(SEC)

5. Capital Structure and Cost of Capital
5.1 Is the proposed capital structure, rate of return on equity, short-term and long-term debt rate appropriate?

20. [Ex.7/1/2/p.5, Ex.7/2/2/p.5, Ex.7/3/1/p.4]
Why is the Applicant proposing to move the GS>50 and USL rate classes that are above the Board's policy range, over a period of two years?

RESPONSE:

As discussed in the response to Board staff interrogatory No. 55, in order to enable decreases in select revenue to cost ratios it will be necessary to increase others.

CNPI acknowledges that its proposal to adjust the revenue to cost ratios and fixed & variable ratios is unconventional. However, the goal of harmonizing electricity distribution rates is an overarching principle and ought to lead to fairness in rates to all customers and contribute to reduced regulatory reporting and simplified rate making in the future.

5. Capital Structure and Cost of Capital

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

49. Reference: Exhibit 45, Tab 1, Schedule1, page 3

a) Please explain why CNPI has not calculated all affiliated long-term debt that is callable on demand at the Board's deemed rate of 4.41%?

b) Please identify the holder of the third-party debt and provide the excerpts and reference to the Board decisions which reviewed this in prior rate applications.

RESPONSE:

a) CNPI considers the promissory notes fixed rate notes. The notes were issued in 2008 and 2009 with no subsequent changes. The callable on demand feature provides flexibility to replace the notes with third party debt when the balance is of efficient size or other circumstances justify the replacement.

b) CNPI's 7.092% senior unsecured notes due August 14, 2018 are held by Canada Life Assurance Company, Sun Life Assurance Company of Canada, and Manufactures Life Insurance Company.

Per the Board's Decision (EB-2008-0222 and EB-2008-0223) dated July 15, 2009 – pages 20 and 21.

Long-term Debt

"CNPI has third-party long term debt of $30 million in senior unsecured notes. These were issued on August 14, 2003, bear interest of 7.092% and are payable at maturity on August 14, 2018."

Board Findings

"The Board notes that there are no issues raised with respect to the third-party debt of $30 million, and will allow this debt at its documented rate of 7.092%."

Canadian Niagara Power Inc.

EB-2012-0112

Response to Smart Meters Interrogatories

6. Smart Meters

6.1
Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

(OEB)

Smart Meters

Issue 6.1
Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

51. Ref: E10/T1/S1/p.21-27 – Smart Meter costs

On page 21, 25 and 27 CNPI noted that it included "only costs deemed to be incremental in carrying out the Smart Meter Project… Since ODS costs were offset by cost savings achieved by implementing remote meter reading and moving away from manual meter reading, no ODS costs are reflected in the incremental Smart Meter OM&A costs". Please identify the cost of the ODS and the offsetting cost savings for all three service territories.

RESPONSE:

Please see tables 6.1, 6.2 and 6.3 below outlining the calculations behind the conclusion that no ODS costs are reflected in the incremental Smart Meter OM&A costs, with exception to CNPI-EOP for 2010. For CNPI-EOP, in 2010 the $1,534 calculated incremental costs were included as part of the overall analysis of incremental Smart Meter OM&A costs that was performed. This analysis included comparing the sum of AMI, ODS and miscellaneous Smart Meter costs for 2010 against the budgeted meter reading expenses per below. Please refer to additional comments provided in Board Interrogatory Q 54 below.

Table 6.1: CNPI – FE Analysis of Manual Meter Reading Expense and ODS Costs

	2009	2010	2011	2012
Meter Reading Expenses - Budget **(A)**	173,767	173,767	173,767	173,767
Meter Reading Expenses - Actual **(B)**	195,794	119,866	28,828	27,837
ODS Costs - Actual **(C)**	-	11,929	26,186	26,400
Total - Meter Reading Expenses + ODS Costs Actual	195,794	131,795	55,014	54,237
Difference	- 22,027	41,972	118,753	119,530

Conclusion:
Manual meter reading expenses budget exceeds the sum of actual manual meter reading and ODS costs combined for 2010 to 2012. Therefore, $Nil recorded as ODS incremental Smart Meter OM&A costs. For 2009, because there were no ODS costs incurred, $Nil was recorded as ODS incremental Smart Meter OM&A costs.

Notes:
(A) Used 2009 budgeted amount total of $173,767 per 2009 rate application (EB-2008-0222 for OEB 5310) and assume constant value for 2009, 2010, 2011 and 2012 for hypothetical manual meter reading expenses budget
(B) 2009 to 2011 is actual meter reading expenses per OEB 5310, and 2012 value derived from 2012 budget as provided in rate application
(C) 2009 to 2011 is actual ODS costs that are a part of costs included in OEB 5175, and 2012 value derived from 2012 budgeted ODS costs within OEB 5310 as provided in rate application

Table 6.2: CNPI – EOP Analysis of Manual Meter Reading Expense and ODS Costs

	2009	2010	2011	2012
Meter Reading Expenses - Budget **(A)**	54,536	54,536	54,536	54,536
Meter Reading Expenses - Actual **(B)**	57,977	58,371	11,912	13,684
ODS Costs - Actual **(C)**	-	1,534	5,966	6,000
Total - Meter Reading Expenses + ODS Costs Actual	57,977	59,905	17,878	19,684
Difference	- 3,441	- 5,369	36,658	34,852

Conclusion:

Manual meter reading expenses budget exceeds the sum of actual manual meter reading and ODS costs combined for 2011 and 2012. Therefore, $Nil recorded as ODS incremental Smart Meter OM&A costs. For 2009, because there were no ODS costs incurred, $Nil was recorded as ODS incremental Smart Meter OM&A costs. For 2010, although the difference was $5,369, CNPI included only the $1,534 relating to ODS costs in the overall analysis of incremental Smart Meter OM&A costs that was performed. This analysis that was completed included comparing the sum of AMI, ODS and miscellaneous Smart Meter costs to the meter reading expenses budget per above. The remaining $3,835 was for actual manual meter reading expenses that exceeded budget, therefore deemed not to be incremental Smart Meter OM&A.

Notes:

(A) Used 2009 budgeted amount total of $54,536 per 2009 rate application (EB-2008-0223 $54,536 for OEB 5310) and assume constant value for 2009, 2010, 2011 and 2012 for hypothetical manual meter reading expenses budget

(B) 2009 to 2011 is actual meter reading expenses per OEB 5310, and 2012 value derived from 2012 budget as provided in rate application

(C) 2009 to 2011 is actual ODS costs that are a part of costs included in OEB 5175, and 2012 value derived from 2012 budgeted ODS costs within OEB 5310 as provided in rate application

Table 6.3: CNPI – PC Analysis of Manual Meter Reading Expense and ODS Costs

	2009	2010	2011	2012
Meter Reading Expenses - Budget **(A)**	98,433	98,433	98,433	98,433
Meter Reading Expenses - Actual **(B)**	100,131	63,618	28,960	40,547
ODS Costs - Actual **(C)**	-	9,330	16,578	15,600
Total - Meter Reading Expenses + ODS Costs Actual	100,131	72,948	45,538	56,147
Difference	- 1,698	25,485	52,895	42,286

Conclusion:

Manual meter reading expenses budget exceeds the sum of actual manual meter reading and ODS costs combined for 2010 to 2012. Therefore, $Nil recorded as ODS incremental Smart Meter OM&A costs. For 2009, because there were no ODS costs incurred, $Nil was recorded as ODS incremental Smart Meter OM&A costs.

Notes:

(A) Used 2009 budgeted amount total of $98,433 per 2009 rate application (EB-2008-0224 $98,433 for OEB 5310) and assume constant value for 2009, 2010, 2011 and 2012 for hypothetical manual meter reading expenses budget

(B) 2009 to 2011 is actual meter reading expenses per OEB 5310, and 2012 value derived from 2012 budget as provided in rate application

(C) 2009 to 2011 is actual ODS costs that are a part of costs included in OEB 5175, and 2012 value derived from 2012 budgeted ODS costs within OEB 5310 as provided in rate application

(OEB)

Smart Meters

Issue 6.1
Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

52. Ref: E10/T1/S1/p.21-22 – Web Presentment

On page 22 CNPI states "costs for the Web Presentment tool that are incremental to CNPI's normal day-to-day operations are for fees to WhiteCap for system setup and ongoing monthly service charges. These costs are justified on the basis that the Web Presentment service is required to allow consumers to benefit from the SMI by having access to their energy consumption data.

a) Please confirm that CNPI has included costs for the Web Presentment service.
b) Please provide the details of this expense for all three service territories.

RESPONSE:

a) In the Smart Meter models, CNPI has included in the capital costs section, an estimated $8,000 one-time set-up fee that is be paid to WhiteCap once the web presentment agreement is signed. For CNPI – FE, please refer to E10/T1/S2, for CNPI – EOP, refer to E10/T1/S4 and for CNPI – PC, refer to E10/T1/S. There were no incremental Smart Meter OM&A costs that were recorded in the models, as the savings derived from the reduction in manual meter reading expenses during 2012 was greater than all Smart Meter related OM&A costs that were budgeted to be incurred (i.e. AMI, ODS, and web presentment OM&A costs, etc.).

b) The estimated $8,000 one-time set-up fee was allocated based on customer base; $4,400 for CNPI – FE, $1,000 for CNPI – EOP and $2,600 for CNPI –

PC. These costs are included in 1.6.3 in the 2012 column of the '2. Smart_Meter_Costs' tab of the smart meter models referred to in a) above.

(OEB)

Smart Meters

Issue 6.1
Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

53. Ref: Exhibit 10 – Smart Meter costs

Please provide a table detailing the per meter costs (capital and operating cost) for each of the three service territories. Also please provide a detailed explanation how these costs compare to other distributors in the Niagara Erie Power Alliance (NEPA)..

RESPONSE:

Please see Table 6-4 below for table detailing the per meter costs (capital and operating costs) for each of the three service territories, as well as other distributors within NEPA that have already submitted applications for smart meter dispositions. The remaining NEPA distributors that have yet to file for smart meter disposition are: Brantford Power Inc., Haldimand County Hydro Inc., and Niagara Peninsula Energy Inc. Given that there is no record of smart meter information for these three LDC's, CNPI is not able to compare capital and OM&A costs. Additionally, although Horizon Utilities is a member of NEPA, it did not participate in the NEPA Smart Meter program implementation discussions, and therefore has not been included in the analysis below.

CNPI would like to point that although all NEPA members worked together to come up with a common project plan, a common AMI solution, and a single vendor for several critical phases of the project (i.e. Sensus for AMI system, Olameter for meter change-out services, etc.), each LDC in NEPA still has its

own unique characteristics (i.e. geographical, mix of Residential and GS<50 rate class customers), thus resulting in varying overall costs on a per meter basis.

For those LDC's that are noted in Table 6-3 below, CNPI's costs per meter are most comparable to Brant County Power, Niagara-on-the-Lake Hydro Inc and Norfolk Dist. Inc. This is primarily due to the fact that each of these service areas each have a similar number of Smart Meter customers in total, they each have large rural square kilometer components relative to urban square kilometer components, and have a similar number of customers per square kilometer. For CNPI (along with the other 3 LDCs noted above), having a large rural service area meant more significant upfront fixed costs incurred for Regional Collectors to ensure appropriate and timely communication of smart meter reads, which directly translated to an increase in total smart meter costs per customer. For those LDCs within NEPA that have a larger customer base and a higher number of customers per square kilometer (i.e. Welland Hydro-Electric Systems Corp), the fixed costs incurred for Regional Collectors were divided out amongst a larger number of customers, therefore lessening the overall costs per smart meter as compared to CNPI.

Within the NEPA group, the costs beyond minimum functionality including CIS development, MDMR integration, and TOU billing implementation costs vary significantly as each LDC has its own system. Some LDCs discussed below did not record any capital costs beyond minimum functionality as part of their Smart Meter disposition application. Although CNPI was unable to come up with a common solution within NEPA, it was able to take a collaborative approach with its affiliate API and associates Westario Power Inc and Grimsby Power Inc. As such, CNPI is confident that these costs are reasonable and were prudently incurred.

CNP's Smart Meter incremental OM&As costs are minimal as compared to other LDC's within NEPA. CNPI interpreted the Board's directive regarding incremental OM&A costs such that only the difference between Smart Meter OM&A costs now being incurred (i.e. the sum of AMI, ODS and miscellaneous Smart Meter OM&A costs), and the savings derived from a reduction in other meter-related expenses (i.e. manual meter read costs), was to be recorded as incremental per below.

Table 6.4: CNPI Analysis of Smart Meter Costs as Compared to NEPA Distributors

	CNPI - FE (A)	CNPI - EOP (A)	CNPI - PC (C)	Brant County Power (D)	Grimsby Power (E)	Niagara-on-the-Lake Hydro Inc (F)	Norfolk Power Dist Inc. (G)	Welland Hydro-Electric Systems Corp (H)
Total Number of Smart Meter Installations	**15,584**	**3,533**	**9,077**	**9,612**	**10,386**	**8,078**	**18,796**	**21,956**
Capital Costs								
1.1 Advance Metering Communication Device (AMCD)	$ 2,130,909	$ 644,083	$ 1,432,822	$ 1,148,603	$ 1,352,445	$ 1,147,450	$ 2,514,266	$ 2,790,070
1.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	234,880	187,610	230,237	228,714	150,280	218,595	296,017	207,883
1.3 Advanced Metering Control Computer (AMCC)	-	-	-	177,267	-	-	-	-
1.4 Wide Area Network (WAN)	-	-	-	-	-	-	-	-
1.5 Other AMI Capital Costs Related To Minimum Functionality	111,191	38,943	64,883	114,293	7,500	253,126	709,886	34,911
1.6 Capital Costs Beyond Minimum Functionality	180,000	45,000	110,000	-	-	268,479	111,341	-
Total Capital Costs	**$ 2,656,980**	**$ 915,636**	**$ 1,837,943**	**$ 1,668,877**	**$ 1,510,225**	**$ 1,887,650**	**$ 3,631,510**	**$ 3,032,864**
Total Capital Costs per Smart Meter Installed	**$ 170.49**	**$ 259.17**	**$ 202.48**	**$ 173.62**	**$ 145.41**	**$ 233.68**	**$ 193.21**	**$ 138.13**
OM&A Costs								
2.1 Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ 138,541	$ 58,267	$ -	$ 21,800	$ 2,011
2.2 Incremental AMRC (includes LAN) OM&A Costs	-	-	-	40,951	116,026	-	195,059	-
2.3 Incremental AMCC OM&A Costs	16,341	7,034	8,377	20,823	-	71,371	-	133,966
2.4 Incremenal WAN OM&A Costs	-	-	-	-	-	-	-	-
2.5 Incremental Other AMI OM&A Costs Related To Minimum Functionality	9,128	5,078	7,547	95,292	54,737	48,187	47,487	129,891
2.6 Incmremental OM& A Costs Beyond Minimum Functionality	-	-	-	-	43,280	45,733	-	-
Total OM&A Costs	**$ 25,469**	**$ 12,112**	**$ 15,924**	**$ 295,607**	**$ 272,310**	**$ 165,291**	**$ 264,346**	**$ 265,868**
Total OM&A Costs per Smart Meter Installed	**$ 1.63**	**$ 3.43**	**$ 1.75**	**$ 30.75**	**$ 26.22**	**$ 20.46**	**$ 14.06**	**$ 12.11**
Total Capital + OM&A Costs per Smart Meter Installed	**$ 172.13**	**$ 262.59**	**$ 204.24**	**$ 204.38**	**$ 171.63**	**$ 254.14**	**$ 207.27**	**$ 150.24**

Notes:

(A) Information obtained from smart meter model dated 20120511, submitted in EB-2012-0112

(B) Information obtained from smart meter model dated 20120511, submitted in EB-2012-0112

(C) Information obtained from smart meter model dated 20120511, submitted in EB-2012-0112

(D) Information obtained from smart meter model dated 20120619, submitted in EB-2012-0265

(E) Information obtained from smart meter model dated 20111103, submitted in EB-2011-0273

(F) Information obtained from smart meter model dated 20120618, submitted in EB-2012-0036

(G) Information obtained from smart meter model dated 20111128, submitted in EB-2011-0272

(H) Information obtained from smart meter model dated 20110305, submitted in EB-2011-0415

(OEB)

Smart Meters

Issue 6.1
Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

54. Ref: E10/T1/S2; T10/T1/S4 and E10/T1/S6 - Smart Meter Model – Interest on OM&A and Depreciation Expenses

In the Smart Meter Model Version 2.17 filed by CNPI, the utility has relied upon sheet 8B to calculate the interest on OM&A and depreciation/amortization expenses. Sheet 8B calculates the interest based on the average annual balance of deferred OM&A and depreciation/amortization expenses based on the annual amounts input elsewhere in the model.

For distributors that have the appropriate data, the more accurate and preferred method for calculating the interest on OM&A and depreciation/amortization expense is to input the monthly amounts from the sub-account details of Account 1556, using sheet 8A of the model. This approach is analogous to the calculation of interest on SMFA revenues on sheet 8 of the model.

a) Please re-file the smart meter model using the monthly OM&A and depreciation/amortization expense data from Account 1556 records for each of the service territories. CNPI should also take into account any revisions necessary, such as in its response to the preceding interrogatory.
b) If this is not possible, please explain.

RESPONSE:

a) N/A.

b) It is not possible to respond as requested in part a) due to the methodology used to determine the incremental smart meter operating costs. Annual budgeted meter reading costs that were included in the 2009 cost of service rates (OEB account 5310) were compared against the combination of

manual meter reading costs and Smart Meter OM&A costs incurred in 2010 (first transition year from manual meter reading to automated meter reading). The difference between the actual costs in 2010 and the budgeted costs were considered incremental. Since the determination was based on a higher level approach, as opposed to a monthly variance account, it is not possible to respond as requested. In any event, given the amount of interest sought for recovery (i.e. $1,027 for CNPI-FE, $173 for CNPI – EOP, and $688 for CNPI - PC for simple interest on OM&A and Amortization for 2010), any difference would be nominal.

(VECC)

Smart Meters

6.1 Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

14. Reference: Exhibit 7, Tab 1, Schedule 2, page 1

a) Please provide a schedule that compares the weighting factors by customer class for Services, Meter Reading, and Billing & Collecting used in the 2013 Cost Allocation with those used in the previous cost allocation.

RESPONSE:

Weighting Factor Comparison

	Services		Billing and Collecting	
	2009	2013	2009	2013
Residential	1.0	1.0	1.0	1.0
GS <50	2.0	1.4	2.0	1.0
GS>50-Regular	10.0	4.4	7.0	5.0
Street Light	1.0	0.4	1.0	1.8
Sentinel	1.0	0.7	0.1	0.9
Unmetered Scattered Load	1.0	0.9	5.0	1.25

	Meter Reading	
	2009	2013
Residential - Urban - Outside	1.00	1.00
Residential - Urban - Inside	2.00	-
Residential - Rural - Outside	3.00	-
LDC Specific 1	-	1.00
LDC Specific 2	-	12.00
GS - Vehicle with other services	3.00	-
Interval	49.00	-
LDC Specific 3	-	42.00

(OEB)

Smart Meters

Issue 6.2
Is proposed treatment of stranded meter costs appropriate?

No Interrogatories Posed

Canadian Niagara Power Inc.

EB-2012-0112

Response to Cost Allocation Interrogatories

PREFACE TO DRAFT ISSUES:

- **7. COST ALLOCATION,**
- **8. RATE DESIGN, AND**
- **9. RATE HARMONIZATION.**

As an introduction to CNPI's responses to the interrogatories posed in the three issues captioned above and as defined in the Draft Issues List contained in Procedural Order No. 2, dated July 6, 2012, CNPI offers the following preface.

As is discussed in Board Staff Interrogatory No. 55 part b), CNPI is cognizant of the alternative nature of its rate design and its proposal to gain the Board's acceptance of its plan to produce harmonized rates in 2017. In the rate design proposed in this Application, CNPI has presented adjustments to revenue to cost ratios and alterations to existing fixed/variable rate structures that differ from certain generally accepted practices and Board guidelines such as the Staff Report to the Board, "Implementation of the Revisions to the Board's Electricity Distributor Cost Allocation Policy" dated August 4, 2011. In this Application, CNPI has taken the position that the existing rate structures in Fort Erie/Gananoque and Port Colborne are divergent to the point where it is impractical to harmonize rates in a single iteration, (i.e., the 2013 EDR). CNPI, in this Application, presents a proposal that, over the four year regulatory cycle, seeks to accommodate full harmonization with the 2017 rebasing application. CNPI's proposed rate design will yield a fair result and will avoid rate increases that are solely attributable to harmonization. The criteria of fairness to the ratepayers is an integral component of the rate design proposed in this Application.

Simply stated, CNPI's proposed rate design[1] is to create, over time, rates in Fort Erie/Gananoque and Port Colborne that mirror each other. In this application and throughout the IRM phase, each service territory, Fort Erie/Gananoque and Port Colborne will have distribution rates designed on the basis of its specific revenue

[1] Fort Erie/Gananoque proposed rate design, Exhibit 8 Tab 2 Schedule 8; Port Colborne rate design Exhibit 8 Tab 3 Schedule 9.

requirement[2]. The rates that will be ultimately presented to the Board in the 2016 IRM application will have similar, and ideally the same, fixed/variable structure for corresponding rate classes in each service territory. Likewise, the corresponding rate classes will be contributing, through rates, a similar proportion to the class allocated revenue requirements, (i.e., the revenue to cost ratios will be equitable). At this point, the rate design to accommodate the increase in the 2017 revenue requirement over the 2013 Board approved revenue requirement ought to allow equitable sharing across the entirety of CNPI's distribution system.

With this foundation in place, CNPI, in its 2017 rebasing application, ought to be in a position to fully harmonize rates with minimal rate impact arising from harmonization itself. Fort Erie and Port Colborne are contiguous communities, CNPI and the communities it serves are very much aware of the comparison of electricity costs by consumers and pundits. With the interrogatories posed by Board staff and the intervenors it becomes apparent, on the surface, that "mathematically" it is conceivable that rates could be harmonized in 2013 and with rate mitigation, total bill impacts could be controlled. However, in CNPI's opinion this theory is flawed.

Mathematically forcing harmonization of electricity distribution rates overlooks one very important aspect; fairness to the consumer. CNPI has provided a postscript to Energy Probe's Interrogatory No. 76, Rate Harmonization. In this postscript, CNPI takes the interrogatory one step further. CNPI, on the design basis of the interrogatory, calculated the revenue transference between service territories. CNPI has coined the term "revenue transference" in order to monetize the amount of revenue requirement that will transfer between the service territories solely because of harmonization. In this particular instance the consumers in Fort Erie/Gananoque will assume approximately $380,000 that under a standalone design would have been the cost responsibility of Port Colborne consumers.

[2] Fort Erie/Gananoque proposed revenue requirement, Exhibit 6 Tab 6 Schedule 1; Port Colborne proposed revenue requirement, Exhibit 6 Tab 1 Schedule 5.

CNPI favours the phased in approach in which the consumers of the respective service territories will continue to each pay rates based upon their own revenue requirement until such time that it is equitable to harmonize rates. CNPI believes that the proposal it has put before the Board will facilitate equitable rate harmonization in the 2017 rebasing application.

7. Cost Allocation

7.1
Is the proposed CNPI – Fort Erie/Gananoque cost allocation appropriate?

(VECC)

Cost Allocation

7.1 Is the proposed CNPI – Fort Erie/Gananoque cost allocation appropriate?

15. Reference: Exhibit 7, Tab 1, Schedule 2, page 1

a) Please provide a schedule that compares the weighting factors by customer class for Services, Meter Reading, and Billing & Collecting used in the 2013 Cost Allocation with those used in the previous cost allocation.

b) Have the meter capital costs used in Sheet I7.1 been updated to reflect the cost of smart meters by customer class as shown Exhibit 10, Tab 1, Schedules 3 & 5? If yes, please show how the costs used in Sheet I7.1 reconcile with those reported in Exhibit 10. If not, please update Sheet I7.1 and re-run the Cost Allocation for FE/EOP.

RESPONSE:

a) This information was provided in the response to VECC Interrogatory No. 14.

b) No, the meter capital costs used in Sheet I7.1 have not been updated to reflect the cost of smart meters by customer class as shown Exhibit 10, Tab 1, Schedules 3 & 5. The re-run Cost Allocation for Fort Erie/Gananoque is provided together with CNPI's responses to these interrogatories.

(VECC)

Cost Allocation

7.1 Is the proposed CNPI – Fort Erie/Gananoque cost allocation appropriate?

16. Reference: Exhibit 7, Elenchus Cost Allocation Study, page 10

a) Please explain why use of the 2006 CA ratios to determine the value for Primary, Line Transformer and Secondary NCP values is appropriate when FE is losing a major customer and there has been a transfer of EOP GS>50 customers to the GS<50 class since then (see Elenchus Load Forecast Report, pages 10 & 13).

RESPONSE:

With the exception of some GS > 50 customers, all customers receive Secondary distribution, therefore the Classification NCP, Primary NCP, Line Transformer NCP, and Secondary NCP are equal. An update to GS > 50 would ideally be performed with knowledge of demand for each customer in the class at the class peak hour. At a minimum this would require interval meter data for every customer who is not receiving secondary distribution, along with information on whether the customer owns their transformer (the remainder can be assumed to receive secondary distribution). The Primary allocator is over 99% of the Classification NCP allocator, and virtually all GS > 50 customers receive primary distribution. Customers who receive Line Transformation also receive Secondary Distribution. Therefore, we would need to know how much line transformation capacity was provided by GS > 50 customers at the class peak each month.

In the absence of knowledge of what the appropriate Secondary and Line Transformer allocators should be, we can hypothesize that they might be consistent with history, or that they might be related to the customers receiving Line Transformer allowance. However, customers receive line transformer

allowance on the basis of their peak demand. The allocator is on the basis of the class peak. In the 2008 Cost Allocation model, 56% of class kW was eligible for Transformer Ownership Allowance (CA model sheet I6, rows 22 and 23) while the Secondary NCP was 89% of the Primary NCP. So clearly, Transformer Ownership Allowance is not as good an indicator for demand that does not require secondary distribution at class peak. In the filed 2013 Cost Allocation model, 47% of the class kW was eligible for Transformer Ownership Allowance (sheet I6.1, rows 26 and 27). A proportionate decrease in Transformer Ownership Allowance would indicate a proportionate increase in Secondary NCP. In order to assist in determining the impact of various options, we can run extreme case scenarios to determine the sensitivity to change. Please see the table below for revenue to cost ratios from the initial application, that would result from, no customers supplying their own transformation at the class peak (secondary is 100% of primary), all customers supplying their own transformation at the class peak (secondary is 0), and where the proportion of class peak demand supplied by customer owned transformers is equal to the proportion demand qualifying for Transformer Ownership Allowance.

Impact of changing Secondary Allocation

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
As Filed	100.00%	87.39%	115.99%	129.49%	102.08%	82.20%	237.81%
Zero Secondary, Line Transformer	100.00%	82.69%	106.20%	170.41%	102.08%	80.47%	230.82%
Secondary, Line Transformer = Primary	100.00%	87.75%	116.76%	127.32%	102.08%	82.33%	238.32%
Secondary, Line Transformer based on TFOA	100.00%	86.00%	113.02%	138.95%	102.08%	81.70%	235.78%

7. Cost Allocation

7.2
Is the proposed CNPI – Port Colborne cost allocation appropriate?

(VECC)

7. Cost Allocation

7.2 Is the proposed CNPI – Port Colborne cost allocation appropriate?

17. Reference: Exhibit 7, Tab 2, Schedule 2, page 1

a) Please provide a schedule that compares the weighting factors by customer class for Services, Meter Reading, and Billing & Collecting used in the 2013 Cost Allocation with those used in the previous cost allocation.

b) Have the meter capital costs used in Sheet I7.1 been updated to reflect the cost of smart meters by customer class as shown Exhibit 10, Tab 1, Schedules 3 & 5? If yes, please show how the costs used in Sheet I7.1 reconcile with those reported in Exhibit 10. If not, please update Sheet I7.1 and re-run the Cost Allocation for PC.

RESPONSE:

a) This information was provided in the response to VECC Interrogatory No. 14.

b) No, the meter capital costs used in Sheet I7.1 have not been updated to reflect the cost of smart meters by customer class as shown Exhibit 10, Tab 1, Schedules 3 & 5. The re-run Cost Allocation for Port Colborne is provided together with CNPI's responses to these interrogatories.

(VECC)

Cost Allocation

7.2 Is the proposed CNPI – Port Colborne cost allocation appropriate?

18. Reference: Exhibit 7, Elenchus Cost Allocation Study, page 10

    a) Please explain why using of the 2006 CA ratios to determine the value for Primary, Line Transformer and Secondary NCP values is appropriate when PC is losing a major customer in 2012 (see Elenchus Load Forecast Report, page 13).

RESPONSE:

With the exception of some GS > 50 customers, all customers receive Secondary distribution, therefore the Classification NCP, Primary NCP, Line Transformer NCP, and Secondary NCP are equal. An update to GS > 50 would ideally be performed with knowledge of demand for each customer in the class at the class peak hour. At a minimum, this requires interval meter data for every customer, who is not receiving secondary distribution; along with information on whether the customer owns their transformer (the remainder can be assumed to receive secondary distribution). All GS > 50 customers receive primary distribution. Customers who receive Line Transformation also receive Secondary Distribution. Therefore, CNPI needs to know how much line transformation capacity was provided by GS > 50 customers at the class peak each month.

In the absence of knowledge of what the appropriate Secondary and Line Transformer allocators should be, CNPI can hypothesize that they might be consistent with history, or that they might be related the customers receiving Line Transformer allowance. However, customers receive line transformer allowance on the basis of their peak demand. The allocator is on the basis of the class peak. In the 2008 Cost Allocation model, 62% of class kW was eligible for

Transformer Ownership Allowance (CA model sheet I6, rows 22 and 23) while the Secondary NCP was 79% of the Primary NCP. So clearly, Transformer Ownership Allowance is not as good for demand that does not require secondary distribution at class peak. In the filed 2013 Cost Allocation model, 68% of the class kW was eligible for Transformer Ownership Allowance (sheet I6.1, rows 26 and 27). A proportionate increase in Transformer Ownership Allowance would indicate a proportionate decrease in Secondary NCP. In order to assist in determining the impact of various options, CNPI can run extreme case scenarios to determine the sensitivity to change. Please see the attached table below for revenue to cost ratios from the initial application, that would result from, no customers supplying their own transformation at the class peak (secondary is 100% of primary), all customers supplying their own transformation at the class peak (secondary is 0), and when the proportion of class peak demand supplied by customer owned transformers is equal to the proportion demand qualifying for Transformer Ownership Allowance.

Impact of changing Secondary Allocation

	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Back-up/Standby Power
As Filed	100.00%	100.27%	98.38%	101.19%	83.26%	95.43%	185.53%	0.00%
Zero Secondary, Line Transformer	100.00%	94.94%	88.95%	125.03%	83.26%	95.43%	174.82%	0.00%
Secondary, Line Transformer = Primary	100.00%	101.03%	99.79%	98.68%	83.26%	95.43%	187.06%	0.00%
Secondary, Line Transformer based on TFOA	100.00%	97.79%	93.88%	110.73%	83.26%	95.43%	180.53%	0.00%

(VECC)

7. Cost Allocation

7.2 Is the proposed CNPI – Port Colborne cost allocation appropriate?

19. Reference: Exhibit 7, Elenchus Cost Allocation Study, pages 9 - 11
Exhibit 8, Tab 3, Schedule 5, page 1
(Note: This question also relates to Issue 9.2)

a) Are the demand allocators for GS>50 class in PC and the combined service area models based on the customer with embedded generation not operating its generation at the time the CP or NCP values occur?

b) If not, please recalculate the CP and NCP values for the GS>50 class based on this assumption and re-run the relevant cost allocation models.

RESPONSE:

a & b) Both embedded generation customers in Port Colborne were commissioned prior to market opening in May 2002. CNPI does not have metered data dedicated to the embedded generators.

7. Cost Allocation

7.3
Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

(OEB)

Cost Allocation

Issue 7.3 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

55. Ref: E7/T1/S2/p. 5

In Appendix 2-O (2011 Filing Requirements), CNPI is proposing to change the revenue-to-cost ratio downward in 2014 for two classes, GS 50-4999 kW and USL.

a) Will the revenue-to-cost ratio be increased for some class to enable these decreases? If so, which class(es)?
b) If the IRM model will be used to accomplish that, does CNPI intend to use one of the options where the model calculates the revised rates, or will another method be used?
c) Aside from the rate design discussed in the previous interrogatory, has CNPI considered any further rate design changes to be made during the IRM period? In particular, has CNPI considered any phasing of rates toward the harmonized rates outlined in E8/T4?

RESPONSE:

a) Yes, in order to enable decreases in select revenue to cost ratios it will be necessary to increase others. To accomplish this, CNPI has increased the revenue to cost ratios of customer classes with ratios less than unity; in this particular case the Residential and Street Lighting customer classes.

b) CNPI acknowledges that its proposal to adjust the revenue to cost ratios and fixed & variable ratios is unconventional. However, the goal of harmonizing electricity distribution rates is an overarching principle and ought to lead to fairness in rates to all customers and contribute to reduced regulatory reporting requirements and simplified rate making in the future. Accordingly, in this Application CNPI is proposing a pre-harmonization alignment.

It is CNPI's goal to use as much as possible, the existing functionality of the Board's IRM models. Use of Board models will provide transparency of the process and allow a more streamline review process for Board Staff and the intervenor community.

It is CNPI's objective in this rate Application to attain the Board's approval of the rate design process presented and acceptance of the principle that the rate structures may be tuned during the three years of IRM such that efficient harmonization of rates is possible in the 2017 EDR.

CNPI recognizes that each successive IRM application filed during the incentive phase will require approval by the Board panel. Each incremental step approved during the incentive phase ought to gradually bring the rate structures (revenue to cost ratios and fixed & variable ratios) closer together and allow full harmonization in 2017.

c) Discussed in part b).

(EP)

7. Cost Allocation

7.3 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

68. Ref: Exhibit 7, Tab 1, Schedule 2

a) **Please show the 2014 revenue to cost ratios for all rate classes in 2014 based on reducing the GS >50 and USL classes to 120% in Table 4.**

b) **Please explain why CNPI is not proposing to increase the revenue to cost ratio for the sentinel lighting class of 82.2% as shown in Table 3 to the bottom of the Board range of 85%?**

c) **Why is CNPI proposing to reduce the revenue to cost ratio for the Street Lighting class when the ratio is well within the Policy Range, as shown in Table 3?**

d) **What is the impact on the residential revenue to cost ratio if the sentinel lighting class is increased to 85% in 2013 and the street lighting class is kept at 102.08% and the additional revenues are used to reduce the increase to the residential class?**

e) **Please provide the response to part (a) above with the additional assumption that the sentinel light class revenue to cost ratio is set at 85% and the street lighting class is maintained at 102.08% in 2013 and 2014.**

RESPONSE:

a) See the table below; depending on whether or not the proposal to harmonize rates is accepted, the response may be different.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	8,593,422	726,746	6,783,330	90.81%	7,077,072
GS Less Than 50 kW	1,593,186	138,022	1,709,984	115.99%	1,709,984
GS 50 to 4,999 kW	2,694,082	231,095	3,257,396	120.00%	3,001,804
USL	29,572	2,548	67,778	120.00%	32,938
Sentinel Lighting	78,300	6,121	58,244	82.20%	58,244
Street Lighting	351,226	27,361	331,165	101.14%	327,854
Total	$ 13,339,789	$ 1,131,892	$12,207,897		$ 12,207,897

b) CNPI is not proposing to increase the revenue to cost ratio of the Sentinel Lighting class because its proposal is to incrementally merge the rate structures of Fort Erie/Gananoque with Port Colborne or vice versa.

c) Same reason as explained in part b).

d) See the table below.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	8,593,422	726,746	6,783,330	89.06%	6,926,214
GS Less Than 50 kW	1,593,186	138,022	1,709,984	115.99%	1,709,984
GS 50 to 4,999 kW	2,694,082	231,095	3,257,396	124.75%	3,129,773
USL	29,572	2,548	67,778	178.91%	50,359
Sentinel Lighting	78,300	6,121	58,244	85.00%	60,434
Street Lighting	351,226	27,361	331,165	102.07%	331,132
Total	$ 13,339,789	$ 1,131,892	$12,207,897		$ 12,207,897

e) See table below

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	8,593,422	726,746	6,783,330	90.75%	7,071,603
GS Less Than 50 kW	1,593,186	138,022	1,709,984	115.99%	1,709,984
GS 50 to 4,999 kW	2,694,082	231,095	3,257,396	120.00%	3,001,804
USL	29,572	2,548	67,778	120.00%	32,938
Sentinel Lighting	78,300	6,121	58,244	85.00%	60,434
Street Lighting	351,226	27,361	331,165	102.07%	331,132
Total	$ 13,339,789	$ 1,131,892	$12,207,897		$ 12,207,897

(EP)

7. Cost Allocation

7.3 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

69. Ref: Exhibit 8, Tab 2, Schedule 7 & Schedule 9

Please provide revised bill impacts for Fort Erie and Gananoque based on the revenue to cost ratios that would result based on part (d) of the previous interrogatory. Please provide the separate bill impact calculations as shown in Schedules 7 and 9.

RESPONSE:

The revenue to cost ratios of Interrogatory No. 68 are as shown below.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	8,593,422	726,746	6,783,330	89.06%	6,926,214
GS Less Than 50 kW	1,593,186	138,022	1,709,984	115.99%	1,709,984
GS 50 to 4,999 kW	2,694,082	231,095	3,257,396	124.75%	3,129,773
USL	29,572	2,548	67,778	178.91%	50,359
Sentinel Lighting	78,300	6,121	58,244	85.00%	60,434
Street Lighting	351,226	27,361	331,165	102.07%	331,132
Total	$ 13,339,789	$ 1,131,892	$12,207,897		$ 12,207,897

The resultant rate design (with no additional adjustment to the fixed/variable splits) is provided in the following table:

2013 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	6,926,214	4,403,409	2,522,805	$ 20.92	$ 0.0175
GS Less Than 50 kW	1,709,984	463,679	1,246,305	$ 23.66	$ 0.0255
GS 50 to 4,999 kW	3,235,758	258,305	2,977,453	$ 144.47	$ 7.8416
USL	50,359	17,615	32,744	$ 58.72	$ 0.0346
Sentinel Lighting	60,434	48,965	11,469	$ 4.44	$ 4.9995
Street Lighting	331,132	247,582	83,550	$ 5.58	$ 10.8931
Total	$12,313,882	$ 5,439,556	$ 6,874,326		

The bill impacts for Fort Erie are:

Selected Delivery Charge and Bill Impacts Per Application

Fort Erie

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 39.67	$ 45.95	$ 6.28	15.8%
Residential Non-RPP	800		$ 38.95	$ 47.95	$ 9.00	23.1%
GS<50 kW	2,000		$ 87.05	$ 99.46	$ 12.41	14.3%
GS<50 kW Non-RPP	2,000		$ 85.25	$ 104.46	$ 19.21	22.5%
GS>50 kW	85,000	230	$ 2,767.87	$ 3,002.47	$ 234.60	8.5%
GS>50 kW Non-RPP	85,000	230	$ 2,694.06	$ 3,147.25	$ 453.18	16.8%
USL	800		$ 110.89	$ 97.74	-$ 13.15	-11.9%
Sentinel Lighting	300	5	$ 55.91	$ 66.18	$ 10.26	18.4%
Street Lighting	172,000	490	$23,930.99	$ 26,155.16	$2,224.17	9.3%
Street Lighting Non-RPP	172,000	490	$23,791.19	$ 26,616.34	$2,825.15	11.9%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 110.38	$ 117.63	$ 7.25	6.6%
Residential Non-RPP	800		$ 120.64	$ 131.64	$ 10.99	9.1%
GS<50 kW	2,000		$ 278.15	$ 292.79	$ 14.64	5.3%
GS<50 kW Non-RPP	2,000		$ 287.51	$ 311.15	$ 23.64	8.2%
GS>50 kW	85,000	230	$11,275.71	$ 11,600.81	$ 325.10	2.9%
GS>50 kW Non-RPP	85,000	230	$11,158.72	$ 11,753.68	$ 594.96	5.3%
USL	800		$ 182.81	$ 170.30	-$ 12.51	-6.8%
Sentinel Lighting	300	5	$ 83.93	$ 94.62	$ 10.69	12.7%
Street Lighting	172,000	490	$42,383.48	$ 44,820.29	$2,436.81	5.7%
Street Lighting Non-RPP	172,000	490	$44,320.33	$ 47,680.23	$3,359.90	7.6%

The bill impacts for Gananoque are:

Selected Delivery Charge and Bill Impacts Per Application
Gananoque

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 37.90	$ 43.34	$ 5.44	14.4%
Residential Non-RPP	800		$ 37.90	$ 46.78	$ 8.88	23.4%
GS<50 kW	2,000		$ 82.56	$ 94.49	$ 11.93	14.4%
GS<50 kW Non-RPP	2,000		$ 82.56	$ 103.09	$ 20.53	24.9%
GS>50 kW	44,300	139	$ 1,813.02	$ 1,839.03	$ 26.01	1.4%
GS>50 kW Non-RPP	44,300	139	$ 1,813.02	$ 2,019.91	$ 206.89	11.4%
USL	800		$ 109.53	$ 92.05	-$ 17.49	-16.0%
Sentinel Lighting	300	5	$ 52.36	$ 50.01	-$ 2.35	-4.5%
Street Lighting	46,000	129	$ 5,986.20	$ 6,559.39	$ 573.19	9.6%
Street Lighting Non-RPP	46,000	129	$ 5,986.20	$ 6,741.76	$ 755.56	12.6%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 115.32	$ 123.82	$ 8.50	7.4%
Residential Non-RPP	800		$ 126.55	$ 139.43	$ 12.88	10.2%
GS<50 kW	2,000		$ 290.29	$ 310.00	$ 19.71	6.8%
GS<50 kW Non-RPP	2,000		$ 302.07	$ 332.52	$ 30.45	10.1%
GS>50 kW	44,300	139	$ 6,617.91	$ 6,811.81	$ 193.90	2.9%
GS>50 kW Non-RPP	44,300	139	$ 6,666.70	$ 7,060.89	$ 394.19	5.9%
USL	800		$ 188.17	$ 173.36	-$ 14.81	-7.9%
Sentinel Lighting	300	5	$ 82.70	$ 81.22	-$ 1.48	-1.8%
Street Lighting	46,000	129	$ 11,274.16	$ 12,030.97	$ 756.81	6.7%
Street Lighting Non-RPP	46,000	129	$ 11,813.54	$ 12,833.88	$ 1,020.34	8.6%

(SEC)

7. Cost Allocation
7.3 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

21. [Ex.7]
Please provide a version of the Bill Impact Model for a scenario in which the proposed revenue-to-cost changes rations are implemented in one year instead of two.

RESPONSE:

CNPI's proposal is to design rates for the Fort Erie / Gananoque and the Port Colborne service territories that, over the period of 2013 to 2016, will merge the rate structures and accommodate rate harmonization with the 2017 EDR.

Both VECC and Energy Probe have asked questions related to alternative rate designs. CNPI has responded to several scenarios posed by Energy Probe which it believes satisfies the intent of this interrogatory. The response to these scenarios are found in the responses to Energy Probe interrogatories No.'s 68, 69, 70 and 71.

(VECC)

7. Cost Allocation

7.3 Are the proposed revenue-to-cost ratios for each of CNPI-Fort Erie/Gananoque rate classes appropriate?

20. Reference: Exhibit 7, Tab 1, Schedule 2, page 5

a) Please explain why the ratio for Residential is increased from 87.39% to 89.12% while the ratio for Sentinel Lighting (82.20%) is unchanged.

b) The ratio for Street Lighting is reduced from 102.08% to 101.14% when the initial value is well within the Board's policy range. Exhibit 8, Tab 2, Schedule 1, page 3 suggests that the reduction is due to the rate stress that has been expressed by local municipalities.
- Is the rate stress faced by municipalities greater than that faced by consumers in other customer classes (as evidenced by the letters of comment submitted to the Board relative to this proceeding)?
- Why do municipalities warrant this "special treatment"?

c) Please provide resulting revenue to cost ratios for Residential and Sentinel Lighting based on the following adjustments:
- Leave GS<50 and Street Lighting unchanged from Status Quo
- Adjust GS>50 and USL as proposed
- Offset the revenue shortfall by first increasing Sentinel Lighting ratio until it reaches 87.39% and then increase both it and the Residential ratios in tandem.

d) What adjustments does CNPI propose to make for 2014 in order to offset the revenue shortfall from the proposed reduction in the ratios for GS>50 and USL?

RESPONSE:

a) CNPI is proposing to harmonize distribution rates and as such is proposing revenue to cost ratios that facilitate full harmonization in 2017; CNPI's next cost of service application.

b) CNPI is not attempting to give any particular customer class "special treatment". CNPI is however cognizant of rate stress and bill impacts of all customer classes. Since the 2009 EDR, street lighting customers have experienced rate increases beyond those of some other rate classes. This has been a function of the cost allocation studies and has been properly applied in the past.

In this Application, the cost allocation has indicated that the Street Lighting customer class has now moved beyond the 100% revenue to cost ratio. CNPI has merely recognized this result and historic rate adjustments and has proposed a minor correction down toward 100%.

c) CNPI has provided this type adjustment in Energy Probe IR No. 68.

d) CNPI proposes to continually move revenue to cost ratios of the Fort Erie/Gananoque and Port Colborne service territories to facilitate future rate harmonization. In this Application, CNPI is proposing a pre-harmonization alignment.

7. Cost Allocation

7.4
Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

(EP)

7. Cost Allocation

7.4 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

70. Ref: Exhibit 7, Tab 2, Schedule 2

a) Please show the 2014 revenue to cost ratios for all rate classes in 2014 based on reducing the USL class to 120% in Table 4.

b) Please assume that the USL revenue to cost ratio is reduced to 120% in 2013 and that the revenue to cost ratio for street lighting is increased to offset the reduction in USL revenues. What is the resulting street lighting revenue to cost ratio?

c) If the resulting revenue to cost ratio for street lighting requested in part (b) above is higher than then next lowest ratio (i.e. 95.44% for sentinel lighting), please increase the revenue to cost ratio such that they are the same for the street lighting and sentinel lighting classes. If required, please repeat this process for the next lowest revenue to cost ratio (i.e. 98.38% for GS<50).

RESPONSE:

The question refers to FortErie/Gananoque but the reference is Port Colborne.

a) See the table below:

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	3,603,206	165,051	3,447,955	100.27%	3,447,955
GS Less Than 50 kW	834,253	32,638	788,083	99.61%	798,351
GS 50 to 4,999 kW	1,532,244	63,200	1,487,332	101.19%	1,487,332
USL	15,668	901	28,169	120.00%	17,901
Sentinel Lighting	3,137	178	2,816	95.43%	2,816
Street Lighting	166,145	9,325	129,007	83.26%	129,007
Total	$ 6,154,653	$ 271,292	$ 5,883,361		$ 5,883,361

b) See the table below:

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	3,603,206	165,051	3,447,955	100.27%	3,447,955
GS Less Than 50 kW	834,253	32,638	788,083	98.99%	793,217
GS 50 to 4,999 kW	1,532,244	63,200	1,487,332	101.19%	1,487,332
USL	15,668	901	28,169	120.00%	17,901
Sentinel Lighting	3,137	178	2,816	95.43%	2,816
Street Lighting	166,145	9,325	129,007	86.35%	134,141
Total	$ 6,154,653	$ 271,292	$ 5,883,361		$ 5,883,361

c) Not required.

(EP)

7. Cost Allocation

7.4 Are the proposed revenue-to-cost ratios for each of CNPI – Fort Erie/Gananoque rate classes appropriate?

71. Ref: Exhibit 8, Tab 3, Schedule 8 & Schedule 10

Please provide revised bill impacts for Port Colborne based on the revenue to cost ratios that would result based on parts (b) and (c) of the previous interrogatory. Please provide the separate bill impact calculations as shown in Schedules 7 and 9.

RESPONSE:

Rate impacts arising from part b) of Energy Probe Interrogatory No. 70

The revenue to cost ratios requested are shown in the table below:

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	3,603,206	165,051	3,447,955	100.27%	3,447,955
GS Less Than 50 kW	834,253	32,638	788,083	98.99%	793,217
GS 50 to 4,999 kW	1,532,244	63,200	1,487,332	101.19%	1,487,332
USL	15,668	901	28,169	120.00%	17,901
Sentinel Lighting	3,137	178	2,816	95.43%	2,816
Street Lighting	166,145	9,325	129,007	86.35%	134,141
Total	$ 6,154,653	$ 271,292	$ 5,883,361		$ 5,883,361

The resultant rate design (with no additional adjustment to fixed/variable splits) is provided in the following table:

2013 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	3,447,955	1,789,511	1,658,443	$ 18.29	$ 0.0258
GS Less Than 50 kW	793,217	389,254	403,963	$ 36.53	$ 0.0171
GS 50 to 4,999 kW	1,613,981	612,979	1,001,002	$ 646.60	$ 3.2118
USL	17,901	6,476	11,425	$ 38.55	$ 0.0196
Sentinel Lighting	2,816	2,486	330	$ 5.05	$ 8.2506
Street Lighting	134,141	90,012	44,130	$ 3.75	$ 10.7137
Total	$ 6,010,010	$ 2,890,717	$ 3,119,293		

The bill impacts for Port Colborne are:

Selected Delivery Charge and Bill Impacts Per Application
Port Colborne

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 40.01	$ 49.29	$ 9.29	23.2%
Residential Non-RPP	800		$ 45.53	$ 56.97	$ 11.45	25.1%
GS<50 kW	2,000		$ 74.25	$ 96.04	$ 21.79	29.3%
GS<50 kW Non-RPP	2,000		$ 88.05	$ 115.24	$ 27.19	30.9%
GS>50 kW	102,500	330	$ 2,525.59	$ 3,014.71	$ 489.12	19.4%
GS>50 kW Non-RPP	102,500	330	$ 3,128.11	$ 3,848.59	$ 720.48	23.0%
USL	800		$ 78.18	$ 63.86	-$ 14.32	-18.3%
Sentinel Lighting	300	5	$ 62.86	$ 69.43	$ 6.57	10.5%
Street Lighting	155,000	445	$10,811.65	$ 13,202.15	$2,390.50	22.1%
Street Lighting Non-RPP	155,000	445	$11,831.02	$ 14,741.36	$2,910.34	24.6%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 116.42	$ 126.15	$ 9.73	8.4%
Residential Non-RPP	800		$ 134.40	$ 147.61	$ 13.21	9.8%
GS<50 kW	2,000		$ 279.18	$ 302.30	$ 23.12	8.3%
GS<50 kW Non-RPP	2,000		$ 306.32	$ 337.96	$ 31.64	10.3%
GS>50 kW	102,500	330	$13,494.19	$ 14,039.77	$ 545.58	4.0%
GS>50 kW Non-RPP	102,500	330	$14,122.15	$ 14,982.41	$ 860.26	6.1%
USL	800		$ 155.24	$ 140.96	-$ 14.28	-9.2%
Sentinel Lighting	300	5	$ 93.05	$ 99.90	$ 6.85	7.4%
Street Lighting	155,000	445	$28,030.30	$ 30,534.32	$2,504.02	8.9%
Street Lighting Non-RPP	155,000	445	$29,943.75	$ 33,302.26	$3,358.51	11.2%

Part c) was not required in the previous interrogatory.

(VECC)

7. Cost Allocation

7.4 Are the proposed revenue-to-cost ratios for each of CNPI-Port Colborne rate classes appropriate?

21. Reference: Exhibit 7, Tab 2, Schedule 2, page 5

a) Please explain why the ratio for GS<50 is increased from 98.38% to 98.99% while the ratios for Street Lighting (83.25%) and Sentinel Lighting (95.44%) are unchanged.

b) Please provide resulting cost ratios for GS<50, Street Lighting and Sentinel Lighting based on the following adjustments:
- Leave Residential and GS>50 unchanged from Status Quo
- Adjust USL as proposed
- As required, offset the revenue shortfall by first increasing the Street Lighting ratio to 95.44%, then increase this ratio and the ratio for Sentinel Lighting in tandem to 98.99% and then, if necessary, increase these two ratios and the GS<50 ratio in tandem.

c) What adjustments does CNPI propose to make for 2014 in order to offset the revenue shortfall from the proposed reduction in the ratio for USL?

RESPONSE:

a) CNPI is proposing to harmonize distribution rates and as such is proposing revenue to cost ratios that facilitate full harmonization in 2017; CNPI's next cost of service application. In this Application, CNPI is proposing a pre-harmonization alignment.

b) CNPI has provided this type adjustment in Energy Probe IR No. 71.

c) CNPI proposes to continually move revenue to cost ratios of the Fort Erie/Gananoque and Port Colborne service territories to facilitate future rate harmonization.

Canadian Niagara Power Inc.

EB-2012-0112

Response to Rate Design Interrogatories

8. Rate Design

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

(OEB)

Rate Design

Issue 8.1
Are the fixed to variable splits for each class appropriate?

56. Ref: E8/T2/S9/\ pp. 11 & 12 and E8/T3/S1/pp. 3 & 4

In light of the estimated impacts in these references (i.e. near 10% while holding the cost of power constant), has CNPI considered phasing in its proposed distribution rates over a longer period, say two years instead of immediately in 2013? If so, why was the more gradual approach not proposed?

RESPONSE:

CNPI is aware of the significance of bill impacts. The generally accepted threshold for presentation of a rate mitigation proposal is 10% increase in total bill. CNPI's proposal does not exceed a 10% increase in total bill.

During this review phase of the Application, CNPI did not believe it was appropriate to introduce a rate mitigation proposal.

(OEB)

Rate Design

Issue 8.1
Are the fixed to variable splits for each class appropriate?

57. Ref: E8/T2/S8/p.3

Please confirm that the column labeled "Service Revenue Requirement" should be "Base Revenue Requirement", i.e. net of Miscellaneous Revenue, in this exhibit and in other Revenue Reconciliation tables with the title "Appendix 2-U"

RESPONSE:

The column labeled "Service Revenue Requirement" is the label used in the Board's Appendix 2-U of the Minimum Filing Requirements, dated June 22, 2011. The Board's updated Minimum Filing Requirements reclassifies this filing requirement as Appendix 2-V and labels the equivalent column as the "Class Specific Revenue Requirement". It is the Base Revenue Requirement, i.e. net of Miscellaneous Revenue, and is shown in E8/T2/S1/p. 3.

This applies to all Revenue Reconciliation tables with the title "Appendix 2-U"; all such tables in the Application have been completed with the same information that is required in Appendix 2-V under the updated Filing Requirements, and as such comply with the updated Filing Requirements.

(VECC)

8. Rate Design

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

22. Reference: Exhibit 8, Tab 2, Schedule 1, page 6

a) Please confirm that the $12.78 Customer Unit cost for EOP/FE's USL class is based on number of connections and not customers.

b) Based on the forecast number of USL customers versus connections for 2013 please convert the $12.78 to an equivalent per customer value.

RESPONSE:

a) $12.78 is based on number of customers.

b) Not applicable.

(VECC)

8. Rate Design

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

23. Reference: Exhibit 8, Tab 3, Schedule 1, pages 5 - 7

a) Given that the application of the current fixed-variable split yields a monthly service charge of $36.53 for the GS<50 class why is CNPI proposing to maintain the value at 2012 levels as opposed to increasing it to the upper end ($34.59) of the Board's policy range?

b) Please confirm that the $10.30 Customer Unit cost for PC's USL class is based on number of connections and not customers.

c) Based on the forecast number of USL customers versus connections for 2013 please convert the $10.30 to an equivalent per customer value.

RESPONSE:

a) CNPI has proposed to keep the monthly service charge at the 2012 level of $30.89 as opposed to raising it to the upper end of the Board's policy in order to maintain a closer relationship with the Fort Erie/Gananoque proposed monthly service charge of $23.66 (See Exhibit 8 Tab 2 Schedule 1 page 7).

b) The $10.30 Customer Unit cost for Port Colborne's USL class is based on number of customers.

c) Not applicable.

(VECC)

8. Rate Design

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

24. Reference: Exhibit 8, Tab 2, Schedule 1, page 5
Exhibit 8, Tab 3, Schedule 1, page 5

a) Please explain why the transformer ownership add-back is applied to both the fixed and variable components of the GS>50 rate design

b) Please recalculate the fixed and variable rates for the EOP/FE and PC GS>50 classes where all of the transformer ownership allowance is applied to the variable portion of the rate.

RESPONSE:

a) There is no implied intent associated with the transformer ownership add-back being applied to both the fixed and variable components of the GS>50 rate design. CNPI's proposed rate design used this methodology in order to proportion the add-back to revenue requirement in the same manner as the balance of the revenue requirement is proportioned.

b) The following tables show reproductions of the rate design with the add-back applied solely to the variable component. Understanding that this is the generally accepted methodology, CNPI's future rate designs will apply the add-back as suggested in this interrogatory.

Fort Erie/Gananoque

Determination of 2013 Base Distribution Rates					
Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	6,931,683	4,406,886	2,524,797	$ 20.94	$ 0.0175
GS Less Than 50 kW	1,709,984	463,679	1,246,305	$ 23.66	$ 0.0255
GS 50 to 4,999 kW	3,129,773	249,844	2,879,929	$ 139.73	$ 7.5847
USL	50,359	17,615	32,744	$ 58.72	$ 0.0346
Sentinel Lighting	58,244	47,190	11,053	$ 4.27	$ 4.8183
Street Lighting	327,854	245,131	82,723	$ 5.53	$ 10.7852
Total	$12,207,897	$ 5,430,346	$ 6,777,551		

Transformer Allowance Addback $ 105,985 (Allocated to GS > 50 to 4,999 kW)

2013 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	6,931,683	4,406,886	2,524,797	$ 20.94	$ 0.0175
GS Less Than 50 kW	1,709,984	463,679	1,246,305	$ 23.66	$ 0.0255
GS 50 to 4,999 kW	3,235,758	249,844	2,985,914	$ 139.73	$ 7.8638
USL	50,359	17,615	32,744	$ 58.72	$ 0.0346
Sentinel Lighting	58,244	47,190	11,053	$ 4.27	$ 4.8183
Street Lighting	327,854	245,131	82,723	$ 5.53	$ 10.7852
Total	$12,313,882	$ 5,430,346	$ 6,883,535		

In Balance? YES

Port Colborne

Determination of 2013 Base Distribution Rates					
Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	3,447,955	1,789,511	1,658,443	$ 18.29	$ 0.0258
GS Less Than 50 kW	793,217	389,254	403,963	$ 36.53	$ 0.0171
GS 50 to 4,999 kW	1,487,332	564,878	922,454	$ 595.86	$ 2.9598
USL	23,035	8,334	14,701	$ 49.60	$ 0.0253
Sentinel Lighting	2,816	2,486	330	$ 5.05	$ 8.2506
Street Lighting	129,007	86,567	42,441	$ 3.61	$ 10.3036
Total	$ 5,883,361	$ 2,841,029	$ 3,042,332		

Transformer Allowance Addback $ 126,649 (Allocated to GS > 50 to 4,999 kW)

2013 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	3,447,955	1,789,511	1,658,443	$ 18.29	$ 0.0258
GS Less Than 50 kW	793,217	389,254	403,963	$ 36.53	$ 0.0171
GS 50 to 4,999 kW	1,613,981	564,878	1,049,103	$ 595.86	$ 3.3661
USL	23,035	8,334	14,701	$ 49.60	$ 0.0253
Sentinel Lighting	2,816	2,486	330	$ 5.05	$ 8.2506
Street Lighting	129,007	86,567	42,441	$ 3.61	$ 10.3036
Total	$ 6,010,010	$ 2,841,029	$ 3,168,981		

In Balance? YES

8. Rate Design

8.2
Are the proposed retail transmission service rates appropriate?

(VECC)

8. Rate Design

8.2 Are the proposed retail transmission service rates appropriate?

25. Reference: Exhibit 8, Tab 2, Schedule 3, pages 1 – 2
Exhibit 8, Tab 3, Schedule 3, page 1

a) Given CNPI's stated intent to fully harmonize its distribution rates, please explain why it is continuing to proposed specific RTSRs for each of its three service territories.

RESPONSE:

a) Please refer to Board staff Interrogatory No. 61.

8. Rate Design

8.3
Are the proposed LV rates appropriate?

(OEB)

Rate Design

Issue 8.3
Are the proposed LV rates appropriate?

58. Ref: E8/T2/S4- Low Voltage Rates in Gananoque

a) The proposed rates appear to be based on a single year of purchases, while the supporting explanation provides information that the annual purchases are much more variable than the fluctuation in customer demand. Please provide information to support the use of 2011, other than that it is the most recent, to show that it is near the average of recent experience. For example provide the cost of purchases, the energy purchased at the LV connection, and/or the amount of power generated locally over a number of years, showing the average and any trend.
b) Please identify the charge determinants that determine the LV costs, eg Hydro One ST Lines, shared DS, specific lines, etc.

RESPONSE:

a) The proposed rates are based on the most recent year and by default a single year. The explanation of fluctuating costs is meant to draw attention to the declining demand on the Gananoque distribution system and the most recent experience with generation. CNPI believes that the most recent data is the best predictor for the test year given the historical decline in customers and demand and the current customer and load forecast.

Low voltage charges are a mix of fixed and variable components; CNPI pays fixed charges related to a Monthly Service Charge and a Meter Charge, however the major component is the Common ST Line Charge which is a demand (KW) based charge. Therefore, the Low Voltage in Gananoque is largely dependent on the coincidence of generation capacity with distribution system demand. Simply stated, the amount of monthly Low Voltage costs from Hydro One is primarily dependent upon the presence of generation

capacity coincident with the monthly distribution system peak. It has no dependence on the amount of energy purchased or energy generated during a particular month.

Low voltage costs over the historic period are:

2009	$41,624
2010	$46,198
2011	$73,981
(previous 12 month period)	$82,329

CNPI proposes to revise its 2013 forecast to the most recent amount of $82,329. In the previous evidence submitted, CNPI had reported the revenue associated with low voltage as opposed to the costs; the difference is recorded in the low voltage variant account.

b) On the basis of the January 2012 invoice from Hydro One, the charge determinants are:

- Monthly Service Charge $292.56
- Meter Charge $466.14
- Common ST Lines $0.668 per kW

(EP)

8. Rate Design

8.3 Are the proposed LV rates appropriate?

72. Ref: Exhibit 8, Tab 3, Schedule 4

Given the unique operating scenario associated with the need for LV, and that in the absence of the need of one customer CNPI could avoid any low voltage charges, has CNPI considered allocating the associated costs on some other basis than the proportion of retail transmission connection rate revenues?

RESPONSE:

No. CNPI has followed the Board's guidelines with respect to the allocation of low voltage costs and the determination of rates.

(VECC)

8. Rate Design

8.3 Are the proposed LV rates appropriate?

26. Reference: Exhibit 8, Tab 2, Schedule 4, page 1
Exhibit 8, Tab 3, Schedule 4, page 1

a) Given CNPI's stated intent to fully harmonize its distribution rates, please explain why it is continuing to proposed specific LV rates for each of its three service territories.

RESPONSE:

a) Please refer to Board staff Interrogatory No. 62.

(VECC)

8. Rate Design

8.3 Are the proposed LV rates appropriate?

27. Reference: Exhibit 8, Tab 2, Schedule 4, page 2

a) Please provide a schedule that sets out the following for EOP:
- The embedded generation (kWh) for 2011
- The purchased kWh for 2011
- Total wholesale power requirements for 2011 (based on the previous two values)
- Total forecast wholesale power requirements for 2013 (based on CNPI's Load Forecast for EOP).

RESPONSE:

As a precursor to this interrogatory, it should be noted that Low Voltage costs from Hydro One to Eastern Ontario Power are demand based and as such are not dependent on the energy but rather the relative demand contributions at the time of peak during the monthly billing period.

a) The information requested is shown below:

	Embedded Generation	Energy Purchased	Total Energy	2013 Forecast Loss Adjusted
	kWh	kWh	kWh	kWh
January	1,690,671	5,169,210	6,859,881	6,699,532
February	1,896,331	4,153,553	6,049,884	5,999,429
March	3,337,205	2,757,839	6,095,044	5,954,146
April	3,526,340	1,520,774	5,047,114	5,126,714
May	3,380,202	1,398,307	4,778,509	4,791,969
June	974,431	3,837,199	4,811,630	5,017,967
July	44,123	5,789,759	5,833,882	5,452,322
August	122	5,583,288	5,583,411	5,537,071
September	27,414	4,802,534	4,829,948	4,832,590
October	1,250,418	3,668,462	4,918,880	5,074,287
November	591,715	4,484,313	5,076,028	5,222,041
December	2,154,913	3,874,497	6,029,410	6,111,955
	18,873,886	47,039,736	65,913,622	65,820,022

(VECC)

8. Rate Design

8.3 Are the proposed LV rates appropriate?

28. Reference: Exhibit 8, Tab 3, Schedule 5, page 1
Exhibit 8, Tab 3, Schedule 4, page 1

a) The first reference (lines 23-27) suggests that the customer with embedded generation does not utilize its own generation but rather purchases its power needs from PC. However, the second reference (lines 16-22) suggests that the customer is using its own generation and could require standby power in the peak period in the event of a forced outage. Please reconcile.

b) Based on the comments in the second reference explain why it is reasonable to forecast that there will be no standby revenues for 2013.

c) Has PC received any revenues from its standby charges over the past four years? If yes, please indicate the revenues received by year.

RESPONSE:

a) The first reference relates to the application of the Standby Power Tariff and the second relates to the application of Hydro One's Low Voltage to CNPI – Port Colborne; the bases of their applications are different.

CNPI – Port Colborne's Standby Power Tariff reads, *"MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS - Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)"*. CNPI – Port Colborne will only apply a Standby Charge in the event that a Standby Customer has less monthly billing demand than the contracted amount. For example, if the contracted standby amount is 5000 kVA and the customer has a billing demand of 3000 kVA, CNPI will bill 2000 kVA of Standby

Charge. If the billing demand was 5500 kVA, no standby charges would apply. In this reference, when the customer requires more energy than its generators can produce, they avoid Standby Charges for the billing period and CNPI will incur Low Voltage charges from Hydro One.

The second reference refers to the low voltage charges that apply to CNPI – Port Colborne from Hydro One. One of CNPI – Port Colborne Standby customers is connected to a distribution line on which Standby Charges apply. (The customer must remain on this distribution line due to the availability of transfer trip technology). In this reference, the higher the customer's billing demand the higher the low voltage charge to CNPI – Port Colborne from Hydro One.

Therefore, when the Standby customer is consuming energy, and particularly so when its generators may have experienced a forced outage, the customer will have avoided the monthly Standby Charge and CNPI incurs low voltage charges.

b) It is important to remain aware that these charges are demand based; the customer need only to withdraw energy from the distribution system for a single event during the month and Standby Charges will be avoided and low voltage costs incurred.

As was referenced in Energy Probe's IR No. 7, Jungbunzlauer plans to become a transmission connected customer in 2012. When it does, its embedded generation, which is currently the larger of CNPI – Port Colborne's two Standby customers, will no longer exist as a customer of CNPI – Port Colborne. The second customer, a supplier to Jungbunzlauer, continues to have a reliance on the distribution system and regularly has a

billing demand greater than the contracted standby amount. Therefore standby charges ought to be avoided under the normal course of events.

In this instance, the contracted standby amount is the minimum demand required to sustain the facility in the event of loss of embedded generation.

c) The current Standby Power contract basis billing regime was introduced following the Board's approval of the 2009 EDR for CNPI – Port Colborne. Under this billing regime the revenues are:

2009 (post 2009 EDR)	$11,729
2010	$4,230
2011	$10,162

8. Rate Design

8.4
Are the proposed loss factors appropriate?

(OEB)

Rate Design

Issue 8.4
Are the proposed loss factors appropriate?

59. Ref: E8/T2/S6/p. 8 – EOP Loss Factors

Does CNPI have an estimate of the portion of its losses that occur in the "North Line" that connects generation to the substation? Has this portion increased with increased importance of the embedded generation relative to other sources?

RESPONSE:

CNPI does not have an estimate of the portion of its losses that occur in the "North Line" that connects generation to the substation. This estimate will be carried out as CNPI explores economic alternatives to rebuilding the North Line. Overall, the 39 kilometre "North Line" represents 22% of the Eastern Ontario Power distribution system.

Although the portion of losses has not been measured, it is not believed that this portion increased significantly with increased contribution of the embedded generation relative to other sources. The entire output of these plans has always been delivered to Eastern Ontario Power and the losses would primarily be a function of that output. In 2005, embedded generation supplied 15% of the annual throughput; in 2011, the embedded generation represented 29% of the annual throughput. The energy delivered in 2005 was 8,918 MWh compared to 10,348 MWh in 2011, an increase of 16%.

(OEB)

Rate Design

Issue 8.4
Are the proposed loss factors appropriate?

60. Ref: E8/T2/S6/pp. 6- 8 & Distribution System Code (DSC) – EOP Loss Factors

In this application CNPI is proposing a Total Loss Factor of 1.1113 for EOP, with a Distribution Loss Factor of 1.0848.

Section 6.2.26 of the DSC states:

> *A distributor shall ensure that the distribution system is adequately protected from potential damage or increased operating costs resulting from the connection of a generation facility. Despite section 2.2.1, if damage to the distribution system or increased operating costs result from the connection of a generation facility other than a micro-embedded generation facility, the distributor shall be reimbursed for these costs by the generator.*

Has CNPI given any consideration of sharing the increased cost of its line losses with the generator? If not, why not. Please explain why the full costs should be borne by the rate payer.

RESPONSE:

CNPI has not given any consideration of sharing the increased cost of its line losses with the generator. The "North Line" is a part of the Eastern Ontario Power ("EOP") distribution system that serves three embedded generation facilities, which are defined as customers in the OEB Distribution System Code. The embedded generation and the "North Line" pre-exist market participation for CNPI-EOP in April, 2003. These hydro plants date back to the early 20th century and three of these plants in particular are connected through a long radial distribution line. At market participation, the distribution system was functionally unbundled from the generation.

CNPI submits that the lines losses should continue to be paid for by ratepayers and not "shared" with the generator for several reasons. The small hydro plants were an integral part of the pre-market distribution system and the then customers enjoyed the benefit of this generation for decades, and historically paid the full cost of the losses. The losses are a function of production and distribution system load, and, although in recent years weather conditions have resulted in modest increased production, the corresponding losses are not a result of these generators adding "increased operating costs" to customers. Power system losses on the "North Line" are a function of energy produced and required by the distribution system. These costs fluctuate and the EOP customers would have been impacted by them since the generation was established in the early 20th century. The customers of EOP have (and continue to) benefitted from this embedded generation in that they pay a reduced Debt Retirement Charge compared to the majority of Ontario electricity consumers.

(EP)

8. Rate Design

8.4 Are the proposed loss factors appropriate?

73. Ref: Exhibit 8, Tab 3, Schedule 7

Does CNPI have any explanation for the relatively low distribution loss factors shown for 2007 and 2009?

RESPONSE:

CNPI assumes the question relates to its service territory in Port Colborne.

Yes. Note that the subsequent years, 2008 and 2010, are higher compared to 2007 and 2009 and are slightly above average. These are a result of the unbilled projection, at that time, not properly accounting for the temporary nature of service being provided to boats in the Welland Canal. Often the connections occur late in the year or at the beginning of the year. The nature of these connections mean a significant demand and consumption may occur over a very short period. When assessing unbilled consumption, the short duration of the connection was not accounted properly and losses were indirectly impacted. This situation has been resolved.

8. Rate Design

8.5
Is CNPI's proposal to continue with its approved Transformer Ownership Allowance appropriate?

(VECC)

8. Rate Design

8.5 Is CNPI's proposal to continue with its approved Transformer Ownership Allowance appropriate?

29. Reference: Exhibit 8, Tab 2, Schedule 2, page 1
Exhibit 8, Tab 3, Schedule 2, page 1

a) What are the 2013 unit line transformer costs from the FE/EOP and the PC cost allocation models?

b) With reference to these values, please comment on the appropriateness of maintaining the allowance at $0.60 / kW for each of the service areas.

RESPONSE:

a) The 2013 unit line transformer costs for the GS > 50 class (the only class eligible to receive the allowance) are $1.3050 for Fort Erie / Eastern Ontario Power, and $1.3656 for Port Colborne.

b) In absence of direction in the Board's Minimum Filing Requirement's on the subject of changes to the Transformer Ownership Allowance, CNPI has interpreted it as an indicator to maintain it at the current amount; $0.60 / kW.

The Transformer Ownership Allowance of $0.60 / kW has been a long-standing rate at CNPI.

Canadian Niagara Power Inc.

EB-2012-0112

Response to Rate Harmonization Interrogatories

9. Rate Harmonization

9.1
Is CNPI's proposed rate harmonization appropriate?

(OEB)

Rate Harmonization

Issue 9.1
Is CNPI's proposed rate harmonization appropriate?

61. Ref: E8/T2/S3/pp.1-2;

CNPI has proposed the following RTSR for the FE and EOP service areas:

Retail Transmission Service Rates (Fort Erie)						
Rate Class	Unit	Current RTSR Network	Proposed RTSR Network		Current RTSR Connection	Proposed RTSR Connection
Residential	kWh	0.0069	0.0071		0.0055	0.0057
General Service Less Than 50 kW	kWh	0.0063	0.0065		0.0048	0.0050
General Service 50 to 4,999 kW	kW	2.5921	2.6588		1.9467	2.0312
Unmetered Scattered Load	kWh	0.0063	0.0065		0.0048	0.0050
Sentinel Lighting	kW	2.0689	2.1222		1.5365	1.6032
Street Lighting	kW	1.9548	2.0051		1.5049	1.5702

Retail Transmission Service Rates (Gananoque)						
Rate Class	Unit	Current RTSR Network	Proposed RTSR Network		Current RTSR Connection	Proposed RTSR Connection
Residential	kWh	0.0043	0.0046		0.0035	0.0036
General Service Less Than 50 kW	kWh	0.0035	0.0038		0.0033	0.0034
General Service 50 to 4,999 kW	kW	1.6621	1.7821		1.3742	1.3967
Unmetered Scattered Load	kWh	0.0040	0.0043		0.0033	0.0034
Sentinel Lighting	kW	1.2260	1.3145		1.0168	1.0334
Street Lighting	kW	1.2197	1.3077		0.9958	1.0121

Please state if CNPI intends to harmonize the RTSR rates between its FE and EOP service territories in the foreseeable future. If not, please explain why not.

RESPONSE:

It is CNPI's goal to fully harmonize electricity distribution rates at its next cost of service proceeding, currently anticipated in 2017. As a means of achieving this goal of harmonization of the RTSR rates, CNPI proposes to achieve harmonization of the electricity distribution rates in Fort Erie and EOP with those of Port Colborne. In this Application, CNPI has proposed a methodology to achieve harmonization in 2017.

With a clear path to harmonization of rates it will be feasible for CNPI to register all its IESO delivery points within a single entity. Particularly with Fort Erie and Port Colborne being contiguous it will be more practical to optimize the system configuration and better utilize available capacity.

(OEB)

Rate Harmonization

Issue 9.1
Is CNPI's proposed rate harmonization appropriate?

62. E8/T2/S4/pp. 1-2 and

CNPI states that at Fort Erie, the distribution system load is supplied in its entirety from the IESO-controlled grid and as such does not attract low voltage charges, while Eastern Ontario Power is connected to Hydro One's 44kV distribution system at a single point of supply and attracts the following LV charges:

Determination of Low Voltage Rates in Gananoque

Low Voltage Revenue Requirement for 2013 $ 91,709

Customer Class	2012 RTSR Connection Rate	Test Year Billing Determinant Volume	UOM	RTSR Connection Revenue	RTSR Revenue Distribution
Residential	0.0035	29,354,957	kWh	$ 102,742	48.2%
GS Less Than 50 kW	0.0033	12,578,164	kWh	$ 41,508	19.5%
GS 50 to 4,999 kW	1.3742	48,371	kW	$ 66,471	31.2%
Unmetered Scattered Load	0.0033	157,458	kWh	$ 520	0.2%
Sentinel Lighting	1.0168	184	kW	$ 187	0.1%
Street Lighting	0.9958	1,674	kW	$ 1,667	0.8%

	Low Voltage Revenue Distribution	Test Year Billing Determinant Volume	UOM	Proposed Low Voltage Distribution Rates Rate	UOM
Residential	$ 44,217	29,354,957	kWh	0.0015	kWh
GS Less Than 50 kW	$ 17,864	12,578,164	kWh	0.0014	kWh
GS 50 to 4,999 kW	$ 28,607	48,371	kW	0.5914	kW
Unmetered Scattered Load	$ 224	157,458	kWh	0.0014	kWh
Sentinel Lighting	$ 81	184	kW	0.4376	kW
Street Lighting	$ 717	1,674	kW	0.4286	kW

	Proposed Low Voltage Rates	Existing Low Voltage Rates	UOM
Residential	0.0015	0.0016	kWh
GS Less Than 50 kW	0.0014	0.0013	kWh
GS 50 to 4,999 kW	0.5914	0.5826	kW
Unmetered Scattered Load	0.0014	0.0013	kWh
Sentinel Lighting	0.4376	0.4311	kW
Street Lighting	0.4286	0.4222	kW

Please state if and when CNPI intends to harmonize LV charges for its FE and EOP service territories. If not, please explain why not.

RESPONSE:

As in the previous interrogatory, Board Staff Interrogatory No. 61, it is CNPI's goal to fully harmonize electricity distribution rates at its next cost of service proceeding, currently anticipated in 2017. As a means of achieving this goal of harmonization of the Low Voltage rates, CNPI proposes to achieve harmonization of the electricity distribution rates in Fort Erie and EOP with those of Port Colborne. In this Application, CNPI has proposed a methodology to achieve harmonization in 2017.

(VECC)

9. Rate Harmonization

9.1 Is CNPI's proposed rate harmonization appropriate?

30. Reference: Exhibit 8, Tab 1, Schedule 1, page 1
Exhibit 8, Tab 2, Schedule 8, page 2

a) Please indicate what CNPI's plan is regarding further adjustments to the fixed and variable components of the rates for each customer class throughout the IRM period.

b) Please confirm that the "next rate proceeding" referred to in the second reference (lines 1-2) is the 2014 IRM-based rate proceeding.

RESPONSE:

a) It is CNPI's proposal to continue with incremental changes to the fixed and variable components such that the monthly service charge and volumetric charge for the corresponding customer classes of each service territory are better aligned with each other. This improved alignment together with more closely aligned revenue to cost ratios ought to better facilitate rate harmonization in the 2017 EDR.

b) Yes the reference is to the 2014 IRM-based rate proceeding.

(VECC)

9. Rate Harmonization

9.1 Is CNPI's proposed rate harmonization appropriate?

31. Reference: Exhibit 8, Tab 2, Schedule 8, page 1

    a) Please explain why the harmonization process entails moving the FE/EOP fixed/variable structure closer to that of Port Colborne as opposed to adjusting the splits for both service areas to overall splits for each class based on the combined revenues for each class from both service areas as set out in Exhibit 8, Tab 4, Schedule 1, page 3.

RESPONSE:

a) It is not CNPI's intention, by design, to move the Fort Erie/EOP fixed/variable structure closer to that of Port Colborne. The intent is to find a common fixed/variable structure that incrementally balances the rates of the two service territories. For example, the GS > 50 kW monthly service charge in Port Colborne is moving toward the structure currently in place at Fort Erie/Gananoque.

That incremental change recognizes the current disparity of rate designs and respects the Board's guidelines with respect to the floor and ceiling of monthly service charges.

(VECC)

9. Rate Harmonization

9.1 Is CNPI's proposed rate harmonization appropriate?

32. Reference: Exhibit 8, Tab 2, Schedule 8, page 1
Exhibit 8, Tab 2, Schedule 1, page 5

a) Please explain why in the tables shown in the two references the "Fixed Component at Existing F/V Split" is different (e.g. for Residential the values are $4,208,880 vs. $4,406,886). Is the column in the second reference really the proposed F/V split?

RESPONSE:

a) The amount referenced in Exhibit 8, Tab 2, Schedule 1, page 5, $4,406,886 is the alternative rate proposal, which tends to maintain status quo rate structures and does not facilitate future rate harmonization.

The amount referenced in Exhibit 8, Tab 2, Schedule 8, page 1, $4,208,880 is the proposed rate design which adjusts the fixed/variable split to facilitate future rate harmonization.

Schedule 8 presents the proposed rate design and is the first incremental step, which CNPI proposes to continue through the IRM process, towards rate harmonization.

9. Rate Harmonization

9.2
Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

(OEB)

Rate Harmonization

Issue 9.2
Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

63. Ref: E7/T3/S1/p.3; E7/3/2 – 2013 Cost Allocation Harmonized
E8/T4/S1/p.5 Setting Target Revenue to Cost Ratios

a) Worksheet O1 in the Exhibit 7 reference shows that the revenue-to-cost ratio of the GS<50 kW class with Status Quo Rates, i.e the existing rates increased by 14.27%, would be 109.36%. The table in Exhibit 8 shows that the revenue-to-cost ratio with target rates would be 116.03%. Please provide the rationale for target rates that would move this ratio away from 100%. Alternatively, please provide a set of target rates that would leave the ratio unchanged or would move it in the direction of 100%.

b) Worksheet O1 in the Exhibit 7 reference shows that the revenue-to-cost ratio of the Street Light class with Status Quo Rates would be 95.61%. The table in Exhibit 8 shows that the revenue-to-cost ratio with target rates would be 92.50%. Please provide the rationale for target rates that would move this ratio away from 100%. Alternatively, please provide a set of target rates that would leave the ratio unchanged or would move it in the direction of 100%.

c) Please provide a complete set of target rates that would yield the revenue-to-cost ratios shown in the Exhibit 7 / 3 / 1 reference, column 'Proposed Ratios', together with any rationale for not using the resulting rates as the reference point for rate harmonization.

RESPONSE:

a) The entire exercise of adjusting the class specific revenue-to-cost ratios was to attain harmonized distribution rates for each of the customer classes which would minimize bill impacts from the perspective of the existing two service territories.

Though unconventional in the sense that one or more customer classes may experience an increase in its specific revenue-to-cost ratio, it is a necessary function to harmonize the rate structures of two sets of customer classes with differing rate structures. In this particular exercise, (i.e., the harmonized plan presented in this Application), the resultant revenue-to-cost ratios are the weighted average of the standalone, service area specific, revenue-to-cost ratios. Put another way, recognizing that the goal is to harmonize rates by 2017 means that it is inappropriate to evaluate the reasonableness of the proposed R/C ratio in the traditional way.

b) The explanation here is the same as provided in part a).

c) In order to provide a complete set of target rates that would yield the revenue-to-cost ratios shown in the Exhibit 7 / 3 / 1 reference, column 'Proposed Ratios' CNPI has reproduced the EXCEL Spreadsheet entitled "2013 EDR Rate Design ALL 20120508.xls" presented with the Application. In the reproduction, the column 'Proposed Ratios' has been held at the revenue-to-cost ratios shown in Exhibit 7 / 3 / 1 reference.

The resultant rate design is detailed in the following series of tables:

Derivation of the Test Year Revenue to Cost Ratios as Determined in the Cost Allocation Study

Customer Class	Allocation of Revenue Requirment including Net Income	Deficiency Factor	Distribution Revenue at Status Quo Rates	Misc. Revenue	Revenue to Cost Ratio		Board's 2011 Policy Range
Residential	12,176,206	1.14272	10,226,386	887,433	91.27%		85% - 115%
GS Less Than 50 kW	2,442,261	1.14272	2,499,053	171,802	109.36%		80% - 120%
GS 50 to 4,999 kW	4,231,471	1.14272	4,746,987	297,612	119.22%		80% - 120%
USL	38,075	1.14272	96,070	3,257	260.87%		80% - 120%
Sentinel Lighting	85,181	1.14272	61,751	5,731	79.22%		80% - 120%
Street Lighting	521,249	1.14272	461,011	37,349	95.61%		70% - 120%
Total	$ 19,494,443		$18,091,258	$ 1,403,184			

Setting Target Revenue to Cost Ratios

Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	12,176,206	887,433	10,226,386	91.27%	10,226,386
GS Less Than 50 kW	2,442,261	171,802	2,499,053	109.36%	2,499,053
GS 50 to 4,999 kW	4,231,471	297,612	4,746,987	119.22%	4,746,987
USL	38,075	3,257	96,070	260.87%	96,070
Sentinel Lighting	85,181	5,731	61,751	79.22%	61,751
Street Lighting	521,249	37,349	461,011	95.61%	461,011
Total	$ 19,494,443	$ 1,403,184	$18,091,258		$ 18,091,258

Balanced? YES

Determination of 2013 Base Distribution Rates

Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	10,226,386	6,109,992	4,116,394	$ 19.82	$ 0.0198
GS Less Than 50 kW	2,499,053	845,941	1,653,112	$ 27.96	$ 0.0228
GS 50 to 4,999 kW	4,746,987	830,970	3,916,018	$ 303.72	$ 5.6642
USL	96,070	33,932	62,137	$ 72.51	$ 0.0407
Sentinel Lighting	61,751	50,232	11,520	$ 4.36	$ 4.9356
Street Lighting	461,011	335,070	125,940	$ 4.90	$ 10.6829
Total	$18,091,258	$ 8,206,137	$ 9,885,121		

Transformer Allowance Addback $ 232,634 (Allocated to GS > 50 to 4,999 kW)

2013 Distribution Rates with Transformer Allowance Addback

Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	10,226,386	6,109,992	4,116,394	$ 19.82	$ 0.0198
GS Less Than 50 kW	2,499,053	845,941	1,653,112	$ 27.96	$ 0.0228
GS 50 to 4,999 kW	4,979,621	871,693	4,107,928	$ 318.60	$ 5.9418
USL	96,070	33,932	62,137	$ 72.51	$ 0.0407
Sentinel Lighting	61,751	50,232	11,520	$ 4.36	$ 4.9356
Street Lighting	461,011	335,070	125,940	$ 4.90	$ 10.6829
Total	$18,323,892	$ 8,246,860	$ 10,077,032		

Adjustment to the Fixed and Variable Allocations

Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Adjusted Fixed Component Percentage	Variable Component at Existing F/V Split	Adjusted Variable Component Percentage	Adjusted Fixed Component	Adjusted Variable Component
Residential	10,192,914	6,193,104	60.76%	3,999,810	39.24%	$ 20.09	$ 0.0192
GS Less Than 50 kW	2,661,871	907,560	34.09%	1,754,311	65.91%	$ 30.00	$ 0.0242
GS 50 to 4,999 kW	4,894,729	856,832	17.51%	4,037,897	82.49%	$ 313.17	$ 5.8405
USL	61,680	21,786	35.32%	39,894	64.68%	$ 46.55	$ 0.0261
Sentinel Lighting	67,891	55,226	81.34%	12,665	18.66%	$ 4.79	$ 5.4263
Street Lighting	444,806	323,293	72.68%	121,513	27.32%	$ 4.73	$ 10.3074
Total	$ 18,323,892	$ 8,357,801		$ 9,966,091			

Balance YES

Comparison of Current Rates to Final Rate Design - Fort Erie/Gananoque						
Customer Class	Proposed Standalone Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 20.94	$ 0.0175	$ 20.09	$ 0.0192	-4.1%	9.7%
GS Less Than 50 kW	$ 23.66	$ 0.0255	$ 30.00	$ 0.0242	26.8%	-5.0%
GS 50 to 4,999 kW	$ 133.68	$ 7.8923	$ 313.17	$ 5.8405	134.3%	-26.0%
USL	$ 58.72	$ 0.0346	$ 46.55	$ 0.0261	-20.7%	-24.5%
Sentinel Lighting	$ 4.27	$ 4.8183	$ 4.79	$ 5.4263	12.2%	12.6%
Street Lighting	$ 5.53	$ 10.7852	$ 4.73	$ 10.3074	-14.5%	-4.4%

Comparison of Current Rates to Final Rate Design - Port Colborne						
Customer Class	Proposed Standalone Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 18.29	$ 0.0258	$ 20.09	$ 0.0192	9.8%	-25.6%
GS Less Than 50 kW	$ 30.89	$ 0.0197	$ 30.00	$ 0.0242	-2.9%	22.9%
GS 50 to 4,999 kW	$ 502.11	$ 3.6513	$ 313.17	$ 5.8405	-37.6%	60.0%
USL	$ 49.60	$ 0.0253	$ 46.55	$ 0.0261	-6.1%	3.2%
Sentinel Lighting	$ 5.05	$ 8.2506	$ 4.79	$ 5.4263	-5.2%	-34.2%
Street Lighting	$ 3.61	$ 10.3036	$ 4.73	$ 10.3074	31.0%	0.0%

CNPI chose not to use the resulting rates as the reference point for rate harmonization due to the potential transference of costs from the customers of a specific customer class of one service territory to the customers of the same customer class of the other service territory.

CNPI is of the opinion that allowing gradual adjustment of the revenue-to-cost ratios, even if it means on a short term basis that the class specific revenue-to-cost ratio may move higher (above unity) to take into account bill impacts, is the more reasonable solution.

(OEB)

Rate Harmonization

Issue 9.2
Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

64. Ref: E7/T3/S1/pp. 2-5 – Harmonized Revenue-to-Cost Ratios

In E7/T3/S1/pp. 2 – 5 CNPI shows a cost allocation approach for harmonized rates between all three service territories. Please show a table (see example below) for FE/EOP as well as PC showing the existing, proposed and target R/C ratios for a proposed rate harmonization in CNPI's next rebasing application. Please explain how CNPI intends to reach these ratios in its next rebasing application – for example, in a single step at 2017 versus gradual steps during the intervening IRM period or the subsequent IRM period.

R/C Ratios

Classes	Current R/C ratios	Proposed R/C ratios				Target Ratio	Policy Range
		2013	2014	2015	2016		

RESPONSE:

CNPI's proposal is to merge the revenue to cost ratios and fixed/variable splits of the two service areas toward each other beginning with this Application. This will serve as a pre-harmonization alignment. The goal is to have corresponding customer classes in each service territory contributing similar proportions to their respective class revenue requirements with similar fixed/variable splits.

CNPI will, on an incremental basis, beginning with this Application and continuing with each of the three IRM applications (2014, 2015 and 2016) adjust the revenue to cost ratios and fixed variable splits. CNPI will avail itself of the most

recent up-to-date information to perform each successive incremental adjustment. The most recent information available will allow CNPI to accommodate any significant changes to the customer class mix.

The goal is that by the completion of the 2016 IRM CNPI will have similar rate structures and similar contributions to the respective class revenue requirements. After this has been accomplished it ought to be practical to harmonize rates with the 2017 cost of service application. It should be possible to design rates where each customer class of each service territory assumes an equitable share of the change in revenue requirement.

In CNPI's opinion it is premature to attempt to predict the future revenue to cost ratios or fixed/variable splits on an annual basis through to 2016. Each successive increment should recognize the previous year's actual class revenue recoveries against plan.

(OEB)

Rate Harmonization

Issue 9.2
Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

65. Ref: E8/T2/S8; E8/T3/S9 and E8/T4/S1/p.11 – Fixed:Variable Ratios leading to Harmonized Rates

On page 11 of the last reference CNPI noted that "to accomplish full harmonization in the future CNPI is proposing to bring the fixed and variable rates closer together over time beginning with this application to facilitate harmonization in a future proceeding.

a) Please provide a table showing the current, proposed and target fixed/variable splits for FE/EOP as well as PC.
b) Please provide the proposed fixed/variable split for each for the years (see example below) during the IRM period (including instances in which CNPI does not plan a change from one year to the next).

Fixed/Variable Component

Classes	Current R/C ratios	Proposed F/V Split				Target Ratio	Policy Range
		2013	2014	2015	2016		

RESPONSE:

Please refer to the CNPI response to Board staff Interrogatory No. 64.

(EP)

9. Rate Harmonization

9.2 Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

74. Ref: Exhibit 7, Tab 3, Schedule 1

a) Please explain why CNPI proposes to decrease the revenue to cost ratio for the GS < 50 class from 109.36% to 107.49% given that it is already within the Policy Range, as shown in Table 3.

b) Please explain why CNPI proposes to decrease the revenue to cost ratio for the GS 50-4,999 class from 119.22% to 112.97% given that it is already lower than the top of the Policy Range, as shown in Table 3.

c) Please explain why CNPI proposes to increase the revenue to cost ratio for the Sentinel Lighting class from 79.22% to 88.82%, when the bottom of the Policy Range is 85%, as shown in Table 3.

d) Please explain why CNPI proposes to decrease the revenue to cost ratio for the Street Lighting class from 95.61% to 92.33% given that it is already within the Policy Range, as shown in Table 3.

e) If the status quo ratios shown in Table 3 for the GS < 50, GS 50-4,999 and Street Lighting were maintained (i.e. 109.36%, 119.22% and 95.61%, respectively), and the sentinel lighting revenue to cost ratio was increased to 85%, and the USL ratio was set to 80%, what would be the resulting revenue to cost ratio for the residential class?

f) Please show the 2014 revenue to cost ratios for all rate classes in 2014 based on reducing the USL class to 120% in Table 4.

RESPONSE:

a) This response applies equally to parts b) through d) of this interrogatory.

CNPI acknowledges that its proposal to adjust the revenue to cost ratios and fixed & variable ratios is unconventional. However, the goal of harmonizing

electricity distribution rates is an overarching principle and ought to lead to fairness in rates to all customers and contribute to reduced regulatory reporting and simplified rate making in the future.

It is CNPI's objective in this rate Application to attain the Board's approval of the rate design process presented and acceptance of the principle that the rate structures may be tuned during the three years of IRM such that efficient harmonization of rates is possible in the 2017 EDR.

CNPI recognizes that each successive IRM application filed during the incentive phase will require approval by the Board panel. Each incremental step approved during the incentive phase ought to gradually bring the rate structures (revenue to cost ratios and fixed & variable ratios) closer together and allow full harmonization in 2017.

e) See the table below.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	12,176,206	887,433	10,226,386	91.80%	10,290,163
GS Less Than 50 kW	2,442,261	171,802	2,499,053	109.36%	2,499,055
GS 50 to 4,999 kW	4,231,471	297,612	4,746,987	119.22%	4,747,148
USL	38,075	3,257	96,070	80.00%	27,203
Sentinel Lighting	85,181	5,731	61,751	85.00%	66,673
Street Lighting	521,249	37,349	461,011	95.61%	461,017
Total	$ 19,494,443	$ 1,403,184	$18,091,258		$ 18,091,258

f) See table below.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	12,176,206	887,433	10,226,386	94.35%	10,600,583
GS Less Than 50 kW	2,442,261	171,802	2,499,053	108.80%	2,485,335
GS 50 to 4,999 kW	4,231,471	297,612	4,746,987	112.97%	4,482,681
USL	38,075	3,257	96,070	120.00%	42,433
Sentinel Lighting	85,181	5,731	61,751	88.82%	69,927
Street Lighting	521,249	37,349	461,011	85.88%	410,300
Total	$ 19,494,443	$ 1,403,184	$18,091,258		$ 18,091,258

(EP)

9. Rate Harmonization

9.2 Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

75. Ref: Exhibit 8, Tab 4, Schedule 1

a) CNPI indicates that it has targeted the weighted averages of the cost to revenue ratios from the separate cost allocation studies filed in Exhibit 7. Please explain why CNPI believes these weighted averages are more appropriate targets than the ratios that result from the harmonized cost allocation study.

b) Please explain how the revenue to cost ratio shown as determined in the cost allocation study in the table on page 4 for the USL class of 260.87% can be higher than that of both the ratios as determined in the cost allocation studies shown in the table on page 3 of Exhibit 8, Tab 2, Schedule 1 (237.81%) and Tab 3 Schedule 1 (185.54%).

c) Please explain how the revenue to cost ratio shown as determined in the cost allocation study in the table on page 4 for the Sentinel Lighting class of 79.227% can be lower than that of both the ratios as determined in the cost allocation studies shown in the table on page 3 of Exhibit 8, Tab 2, Schedule 1 (82.20%) and Tab 3 Schedule 1 (95.43%).

RESPONSE:

a) CNPI's goal is to harmonize rates between Fort Erie/Gananoque and Port Colborne. There are guiding principles in the design of harmonized rates one of which is total bill impact with another being minimization of cost transference.

In this context, cost transference is meant to describe the relationship between what the customers of a particular service territory would pay under discreet (or standalone) rates (i.e., that areas revenue requirement) and what

those same customers will pay with harmonized rates. If not balanced then following harmonization one service territory will assume some portion of the cost contribution of the other.

The intent of weighting the revenue to cost ratios was to create a measure of balance between Fort Erie/Gananoque and Port Colborne. Fort Erie Gananoque has a proposed base revenue requirement of approximately $12 million and Port Colborne is approximately $6 million. The weighted average revenue to cost ratios creates a starting point that tends to balance the relative contribution of each service territory to overall revenue requirement.

b) The cost allocation of the combined service territories or harmonized cost allocation is not an addition of the two individual cost allocation models. CNPI sought to create a new cost allocation which is reflective of the combine loading profiles and harmonized trial balance. In essence it is the creation of a new utility that may or may not reflect the individual attributes of the individual service territories.

c) Same as part b).

(EP)

9. Rate Harmonization

9.2 Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

76. Ref: Exhibit 8, Tab 4, Schedule 1

Please provide a revised analysis in the tables shown in Schedule 1, including the bill impacts assuming that the target revenue to cost ratios shown in the table on page 5 are the same as the ratios shown in the table shown on page 4 with the following exceptions:

- **i) Sentinel Lighting is increased to 80%;**
- **ii) USL is reduced to 80%; and**
- **iii) any revenue shortfall is made up by increasing the ratio for the sentinel lighting and USL classes above 80% to the residential level of 91.27% (if necessary) and then increasing all three classes in tandem (if necessary) to produce the required revenues.**

RESPONSE:

The table below shows the distribution revenue shares by class on the basis of the revenue to cost ratios outlined in the interrogatory. Due to the very sensitive movements in the smaller rate classes some target ratios vary by 0.01%.

Setting Target Revenue to Cost Ratios					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	12,176,206	887,433	10,226,386	91.72%	10,280,000
GS Less Than 50 kW	2,442,261	171,802	2,499,053	109.35%	2,498,893
GS 50 to 4,999 kW	4,231,471	297,612	4,746,987	119.22%	4,747,148
USL	38,075	3,257	96,070	91.81%	31,700
Sentinel Lighting	85,181	5,731	61,751	91.84%	72,500
Street Lighting	521,249	37,349	461,011	95.61%	461,017
Total	$ 19,494,443	$ 1,403,184	$18,091,258		$ 18,091,258

Following the same rate design philosophy as is in the Application the following table shows the determination of the fixed and variable charges.

Determination of 2013 Base Distribution Rates					
Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	10,280,000	6,142,025	4,137,975	$ 19.92	$ 0.0199
GS Less Than 50 kW	2,498,893	845,887	1,653,006	$ 27.96	$ 0.0228
GS 50 to 4,999 kW	4,747,148	830,998	3,916,150	$ 303.73	$ 5.6644
USL	31,700	11,197	20,503	$ 23.92	$ 0.0134
Sentinel Lighting	72,500	58,975	13,525	$ 5.11	$ 5.7947
Street Lighting	461,017	335,075	125,942	$ 4.90	$ 10.6830
Total	$18,091,258	$ 8,224,156	$ 9,867,102		

Transformer Allowance Addback $ 232,634 (Allocated to GS > 50 to 4,999 kW)

2013 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	10,280,000	6,142,025	4,137,975	$ 19.92	$ 0.0199
GS Less Than 50 kW	2,498,893	845,887	1,653,006	$ 27.96	$ 0.0228
GS 50 to 4,999 kW	4,979,782	871,721	4,108,061	$ 318.61	$ 5.9419
USL	31,700	11,197	20,503	$ 23.92	$ 0.0134
Sentinel Lighting	72,500	58,975	13,525	$ 5.11	$ 5.7947
Street Lighting	461,017	335,075	125,942	$ 4.90	$ 10.6830
Total	$18,323,892	$ 8,264,879	$ 10,059,013		

The following series of tables are those found in Exhibit 8 Tab 4 Schedule 1 reproduced under this rate design.

Test of 2013 Calculated Monthly Service Charge				
Customer Class	Customer Unit Cost per Month Avoided Cost	Customer Unit Cost per Month Min. System with PLCC Adj.	Rate Design at Existing F/V Split	Is Rate Design Within Bounds?
	Floor	Ceiling		
Residential	$ 5.25	$ 24.51	$ 19.92	TRUE
GS Less Than 50 kW	$ 11.32	$ 36.06	$ 27.96	TRUE
GS 50 to 4,999 kW	$ 53.52	$ 147.66	$ 318.61	FALSE
USL	$ 0.42	$ 11.41	$ 23.92	FALSE
Sentinel Lighting	$ 0.29	$ 10.45	$ 5.11	TRUE
Street Lighting	$ 0.12	$ 11.45	$ 4.90	TRUE

In the absence of direction in the interrogatory there is no additional adjustments made to the fixed and variable rate components.

Adjustment to the Fixed and Variable Allocations							
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Adjusted Fixed Component Percentage	Variable Component at Existing F/V Split	Adjusted Variable Component Percentage	Adjusted Fixed Component	Adjusted Variable Component
Residential	10,280,000	6,142,025	59.75%	4,137,975	40.25%	$ 19.92	$ 0.0199
GS Less Than 50 kW	2,498,893	845,887	33.85%	1,653,006	66.15%	$ 27.96	$ 0.0228
GS 50 to 4,999 kW	4,979,782	871,721	17.51%	4,108,061	82.49%	$ 318.61	$ 5.9419
USL	31,700	11,197	35.32%	20,503	64.68%	$ 23.92	$ 0.0134
Sentinel Lighting	72,500	58,975	81.34%	13,525	18.66%	$ 5.11	$ 5.7947
Street Lighting	461,017	335,075	72.68%	125,942	27.32%	$ 4.90	$ 10.6830
Total	$18,323,892	$ 8,264,879		$ 10,059,013			

Comparison of Current Rates to Final Rate Design - Fort Erie/Gananoque						
Customer Class	Proposed Standalone Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 20.94	$ 0.0175	$ 19.92	$ 0.0199	-4.9%	13.5%
GS Less Than 50 kW	$ 23.66	$ 0.0255	$ 27.96	$ 0.0228	18.2%	-10.5%
GS 50 to 4,999 kW	$ 133.68	$ 7.8923	$ 318.61	$ 5.9419	138.3%	-24.7%
USL	$ 58.72	$ 0.0346	$ 23.92	$ 0.0134	-59.3%	-61.2%
Sentinel Lighting	$ 4.27	$ 4.8183	$ 5.11	$ 5.7947	19.8%	20.3%
Street Lighting	$ 5.53	$ 10.7852	$ 4.90	$ 10.6830	-11.4%	-0.9%

Comparison of Current Rates to Final Rate Design - Port Colborne						
Customer Class	Proposed Standalone Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 18.29	$ 0.0258	$ 19.92	$ 0.0199	8.9%	-23.0%
GS Less Than 50 kW	$ 30.89	$ 0.0197	$ 27.96	$ 0.0228	-9.5%	15.8%
GS 50 to 4,999 kW	$ 502.11	$ 3.6513	$ 318.61	$ 5.9419	-36.5%	62.7%
USL	$ 49.60	$ 0.0253	$ 23.92	$ 0.0134	-51.8%	-47.0%
Sentinel Lighting	$ 5.05	$ 8.2506	$ 5.11	$ 5.7947	1.3%	-29.8%
Street Lighting	$ 3.61	$ 10.3036	$ 4.90	$ 10.6830	35.8%	3.7%

Appendix 2-U
Harmonized Revenue Reconciliation

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Average for 2013	kWh	kW	Monthly Service Charge	Volumetric						
						kWh	kW					
Residential	Customers	25,689	208,287,976		$ 19.92	$ 0.0199		$ 10,280,000	$ 10,280,000		$ 10,280,000	$ -
GS Less Than 50 kW	Customers	2,521	72,454,602		$ 27.96	$ 0.0228		$ 2,498,893	$ 2,498,893		$ 2,498,893	$ -
GS 50 to 4,999 kW	Customers	228	224,300,691	691,366	$ 318.61		$ 5.9419	$ 4,979,782	$ 4,747,148	$ 232,634	$ 4,979,782	$ -
USL	Connections	39	1,527,929		$ 23.92	$ 0.0134		$ 31,700	$ 31,700		$ 31,700	$ -
Sentinel Lighting	Connections	961	761,037	2,334	$ 5.11		$ 5.7947	$ 72,500	$ 72,500		$ 72,500	$ -
Street Lighting	Connections	5,696	4,475,403	11,789	$ 4.90		$ 10.6830	$ 461,017	$ 461,017		$ 461,017	$ -
Standby Power	Customers	-	-	-	$ -			$ -	$ -		$ -	$ -
Total		35,134	511,807,638	705,489				$ 18,323,892	$ 18,091,258	$ 232,634	$ 18,323,892	$ -

The following tables summarize the bill impacts for each of the service territories comparing existing Board approve electricity distribution rates to the rates developed in this interrogatory.

Selected Delivery Charge and Bill Impacts Per Application

Fort Erie

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 39.67	$ 46.87	$ 7.20	18.1%
Residential Non-RPP	800		$ 38.95	$ 48.87	$ 9.92	25.5%
GS<50 kW	2,000		$ 87.05	$ 98.36	$ 11.31	13.0%
GS<50 kW Non-RPP	2,000		$ 85.25	$ 103.36	$ 18.11	21.2%
GS>50 kW	85,000	230	$ 2,767.87	$ 2,739.68	-$ 28.19	-1.0%
GS>50 kW Non-RPP	85,000	230	$ 2,694.06	$ 2,884.46	$ 190.39	7.1%
USL	800		$ 110.89	$ 45.98	-$ 64.91	-58.5%
Sentinel Lighting	300	5	$ 55.91	$ 73.50	$ 17.59	31.5%
Street Lighting	172,000	490	$ 23,930.99	$ 23,604.21	-$ 326.78	-1.4%
Street Lighting Non-RPP	172,000	490	$ 23,791.19	$ 24,065.39	$ 274.21	1.2%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 110.38	$ 118.56	$ 8.18	7.4%
Residential Non-RPP	800		$ 120.64	$ 132.68	$ 12.03	10.0%
GS<50 kW	2,000		$ 278.15	$ 291.67	$ 13.52	4.9%
GS<50 kW Non-RPP	2,000		$ 287.51	$ 309.91	$ 22.40	7.8%
GS>50 kW	85,000	230	$ 11,275.71	$ 11,333.55	$ 57.84	0.5%
GS>50 kW Non-RPP	85,000	230	$ 11,158.72	$ 11,456.73	$ 298.01	2.7%
USL	800		$ 182.81	$ 117.66	-$ 65.15	-35.6%
Sentinel Lighting	300	5	$ 83.93	$ 102.07	$ 18.14	21.6%
Street Lighting	172,000	490	$ 42,383.48	$ 42,225.98	-$ 157.50	-0.4%
Street Lighting Non-RPP	172,000	490	$ 44,320.33	$ 44,797.66	$ 477.33	1.1%

Selected Delivery Charge and Bill Impacts Per Application

Gananoque

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 37.90	$ 44.26	$ 6.36	16.8%
Residential Non-RPP	800		$ 37.90	$ 47.70	$ 9.80	25.9%
GS<50 kW	2,000		$ 82.56	$ 93.39	$ 10.83	13.1%
GS<50 kW Non-RPP	2,000		$ 82.56	$ 101.99	$ 19.43	23.5%
GS>50 kW	44,300	139	$ 1,813.02	$ 1,749.11	-$ 63.91	-3.5%
GS>50 kW Non-RPP	44,300	139	$ 1,813.02	$ 1,929.99	$ 116.97	6.5%
USL	800		$ 109.53	$ 40.29	-$ 69.25	-63.2%
Sentinel Lighting	300	5	$ 52.36	$ 57.34	$ 4.98	9.5%
Street Lighting	46,000	129	$ 5,986.20	$ 5,920.29	-$ 65.91	-1.1%
Street Lighting Non-RPP	46,000	129	$ 5,986.20	$ 6,102.66	$ 116.45	1.9%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 115.32	$ 124.76	$ 9.44	8.2%
Residential Non-RPP	800		$ 126.55	$ 140.47	$ 13.92	11.0%
GS<50 kW	2,000		$ 290.29	$ 308.88	$ 18.59	6.4%
GS<50 kW Non-RPP	2,000		$ 302.07	$ 331.28	$ 29.21	9.7%
GS>50 kW	44,300	139	$ 6,617.91	$ 6,720.36	$ 102.45	1.5%
GS>50 kW Non-RPP	44,300	139	$ 6,666.70	$ 6,959.28	$ 292.58	4.4%
USL	800		$ 188.17	$ 120.72	-$ 67.45	-35.8%
Sentinel Lighting	300	5	$ 82.70	$ 88.67	$ 5.97	7.2%
Street Lighting	46,000	129	$ 11,274.16	$ 11,381.00	$ 106.84	0.9%
Street Lighting Non-RPP	46,000	129	$ 11,813.54	$ 12,111.69	$ 298.15	2.5%

Selected Delivery Charge and Bill Impacts Per Application **Port Colborne**

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 40.01	$ 46.20	$ 6.20	15.5%
Residential Non-RPP	800		$ 45.53	$ 53.88	$ 8.35	18.4%
GS<50 kW	2,000		$ 74.25	$ 98.87	$ 24.62	33.2%
GS<50 kW Non-RPP	2,000		$ 88.05	$ 118.07	$ 30.02	34.1%
GS>50 kW	102,500	330	$ 2,525.59	$ 3,587.66	$ 1,062.07	42.1%
GS>50 kW Non-RPP	102,500	330	$ 3,128.11	$ 4,421.53	$ 1,293.42	41.3%
USL	800		$ 78.18	$ 44.27	-$ 33.91	-43.4%
Sentinel Lighting	300	5	$ 62.86	$ 57.46	-$ 5.41	-8.6%
Street Lighting	155,000	445	$ 10,811.65	$ 15,488.49	$ 4,676.83	43.3%
Street Lighting Non-RPP	155,000	445	$ 11,831.02	$ 17,027.70	$ 5,196.68	43.9%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 116.42	$ 123.01	$ 6.59	5.7%
Residential Non-RPP	800		$ 134.40	$ 144.12	$ 9.72	7.2%
GS<50 kW	2,000		$ 279.18	$ 305.18	$ 25.99	9.3%
GS<50 kW Non-RPP	2,000		$ 306.32	$ 341.16	$ 34.84	11.4%
GS>50 kW	102,500	330	$ 13,494.19	$ 14,622.45	$ 1,128.26	8.4%
GS>50 kW Non-RPP	102,500	330	$ 14,122.15	$ 15,629.84	$ 1,507.69	10.7%
USL	800		$ 155.24	$ 121.04	-$ 34.20	-22.0%
Sentinel Lighting	300	5	$ 93.05	$ 87.72	-$ 5.33	-5.7%
Street Lighting	155,000	445	$ 28,030.30	$ 32,859.53	$ 4,829.23	17.2%
Street Lighting Non-RPP	155,000	445	$ 29,943.75	$ 35,885.82	$ 5,942.07	19.8%

Post script to Interrogatory

As discussed in Energy Probe Interrogatory No. 75, the issue of cost transference is one of CNPI's guiding principles in the design of rate harmonization. In this interrogatory Energy Probe has provided class specific revenue to cost ratios and asked to follow through the rate design process and produce bill impact information for each rate classification in each service territory. The resultant electricity distribution rates may produce plausible bill impacts but fails to examine the cost transference resulting from the rates.

The following two tables examine the revenues that will be collected from the customers of the Fort Erie/Gananoque and Port Colborne services territories and compares these revenues to the respective revenue requirements.

Appendix 2-U
Fort Erie / Gananoque Revenue Reconciliation

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Average for 2013	kWh	kW	Monthly Service Charge	Volumetric						
						kWh	kW					
Residential	Customers	17,537	144,126,043		$ 19.92	$ 0.0199		$ 7,060,152.74	$ 6,931,683		$ 6,931,683	-$ 128,470
GS Less Than 50 kW	Customers	1,633	48,895,781		$ 27.96	$ 0.0228		$ 1,662,727.97	$ 1,709,984		$ 1,709,984	$ 47,256
GS 50 to 4,999 kW	Customers	149	135,605,948	379,702	$ 318.61		$ 5.9419	$ 2,825,825.99	$ 3,129,773	$ 105,985	$ 3,235,758	$ 409,932
USL	Customers	25	946,114		$ 23.92	$ 0.0134		$ 19,853.93	$ 50,359		$ 50,359	$ 30,505
Sentinel Lighting	Connections	920	747,706	2,294	$ 5.11		$ 5.7947	$ 69,707.44	$ 58,244		$ 58,244	-$ 11,464
Street Lighting	Connections	3,696	2,687,821	7,670	$ 4.90		$ 10.6830	$ 299,263.41	$ 327,854		$ 327,854	$ 28,590
Total		23,960	333,009,413	389,666				$ 11,937,531.48	$ 12,207,897	$ 105,985	$ 12,313,882	$ 376,350

Appendix 2-U
Port Colborne Revenue Reconciliation

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Average for 2013	kWh	kW	Monthly Service Charge	Volumetric						
						kWh	kW					
Residential	Customers	8,152	64,161,933		$ 19.92	$ 0.0199		$ 3,225,477	$ 3,447,955		$ 3,447,955	$ 222,478
GS Less Than 50 kW	Customers	888	23,558,821		$ 27.96	$ 0.0228		$ 835,083	$ 793,217		$ 793,217	-$ 41,866
GS 50 to 4,999 kW	Customers	79	88,694,743	311,664	$ 318.61		$ 5.9419	$ 2,153,919	$ 1,487,332	$ 126,649	$ 1,613,981	-$ 539,938
USL	Customers	14	581,815		$ 23.92	$ 0.0134		$ 11,815	$ 23,035		$ 23,035	$ 11,220
Sentinel Lighting	Connections	41	13,331	40	$ 5.11		$ 5.7947	$ 2,746	$ 2,816		$ 2,816	$ 70
Street Lighting	Connections	2,000	1,787,582	4,119	$ 4.90		$ 10.6830	$ 161,603	$ 129,007		$ 129,007	-$ 32,596
Standby Power	Customers	-	-	-	$ -			$ -	$ -		$ -	$ -
Total		11,174	178,798,225	315,823				$ 6,390,642	$ 5,883,361	$ 126,649	$ 6,010,010	-$ 380,632

In the above examples, the total cost transference is approximately $380,000. That is to say that as a result of the harmonization, the existing customers of the Fort Erie/Gananoque service territory will collectively pick up an additional $380,000 in costs while the customers of Port Colborne enjoy a cost savings.

CNPI's proposal is to incrementally adjust rate structures (cost to revenue ratios and fixed/variable splits) so that this abrupt change in cost structures may be avoided.

Note: the difference in the two tables above is attributable to the rounding of individual rate to two and four decimal places.

(EP)

9. Rate Harmonization

9.2 Is the combined cost allocation supporting CNPI's proposed phased-in rate harmonization appropriate?

77. Ref: Exhibit 8, Tab 4, Schedule 1 &
Exhibit 8, Tab 2, Schedule 7 &
Exhibit 8, Tab 3, Schedule 8

Please provide bill impacts similar to the tables provided for Fort Erie, Gananoque and Port Colborne shown on pages 9 through 11 that show the impact on the customer classes between the (a) rates that would result from this application before any adjustments made for harmonization purposes (i.e. rates used to calculate the Per Application figures shown in the tables shown in Exhibit 8, Tab 2, Schedule 7 and Exhibit 8, Tab 3, Schedule 8 and (b) the rates that would result from Interrogatory #3 above.

RESPONSE:

Please see tables below for response to (a) and (b)

Selected Delivery Charge and Bill Impacts Per Application

Fort Erie

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 45.97	$ 46.87	$ 0.90	2.0%
Residential Non-RPP	800		$ 47.97	$ 48.87	$ 0.90	1.9%
GS<50 kW	2,000		$ 99.46	$ 98.36	-$ 1.10	-1.1%
GS<50 kW Non-RPP	2,000		$ 104.46	$ 103.36	-$ 1.10	-1.1%
GS>50 kW	85,000	230	$ 3,003.34	$ 2,739.68	-$ 263.66	-8.8%
GS>50 kW Non-RPP	85,000	230	$ 3,148.12	$ 2,884.46	-$ 263.66	-8.4%
USL	800		$ 96.14	$ 45.98	-$ 50.16	-52.2%
Sentinel Lighting	300	5	$ 64.42	$ 73.50	$ 9.08	14.1%
Street Lighting	172,000	490	$ 26,523.27	$ 23,604.21	-$ 2,919.06	-11.0%
Street Lighting Non-RPP	172,000	490	$ 26,383.47	$ 24,065.39	-$ 2,318.08	-8.8%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 117.65	$ 118.56	$ 0.92	0.8%
Residential Non-RPP	800		$ 131.66	$ 132.68	$ 1.02	0.8%
GS<50 kW	2,000		$ 292.79	$ 291.67	-$ 1.12	-0.4%
GS<50 kW Non-RPP	2,000		$ 311.15	$ 309.91	-$ 1.24	-0.4%
GS>50 kW	85,000	230	$ 11,601.69	$ 11,333.55	-$ 268.14	-2.3%
GS>50 kW Non-RPP	85,000	230	$ 11,754.67	$ 11,456.73	-$ 297.94	-2.5%
USL	800		$ 168.67	$ 117.66	-$ 51.01	-30.2%
Sentinel Lighting	300	5	$ 92.83	$ 102.07	$ 9.24	9.9%
Street Lighting	172,000	490	$ 45,194.66	$ 42,225.98	-$ 2,968.69	-6.6%
Street Lighting Non-RPP	172,000	490	$ 47,417.09	$ 44,797.66	-$ 2,619.43	-5.5%

Selected Delivery Charge and Bill Impacts Per Application

Gananoque

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 43.36	$ 44.26	$ 0.90	2.1%
Residential Non-RPP	800		$ 46.80	$ 47.70	$ 0.90	1.9%
GS<50 kW	2,000		$ 94.49	$ 93.39	-$ 1.10	-1.2%
GS<50 kW Non-RPP	2,000		$ 103.09	$ 101.99	-$ 1.10	-1.1%
GS>50 kW	44,300	139	$ 1,835.29	$ 1,749.11	-$ 86.18	-4.7%
GS>50 kW Non-RPP	44,300	139	$ 2,016.17	$ 1,929.99	-$ 86.18	-4.3%
USL	800		$ 91.11	$ 40.29	-$ 50.82	-55.8%
Sentinel Lighting	300	5	$ 48.25	$ 57.34	$ 9.08	18.8%
Street Lighting	46,000	129	$ 6,682.84	$ 5,920.29	-$ 762.55	-11.4%
Street Lighting Non-RPP	46,000	129	$ 6,682.84	$ 6,102.66	-$ 580.18	-8.7%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 123.84	$ 124.76	$ 0.92	0.7%
Residential Non-RPP	800		$ 139.45	$ 140.47	$ 1.02	0.7%
GS<50 kW	2,000		$ 310.00	$ 308.88	-$ 1.12	-0.4%
GS<50 kW Non-RPP	2,000		$ 332.52	$ 331.28	-$ 1.24	-0.4%
GS>50 kW	44,300	139	$ 6,808.00	$ 6,720.36	-$ 87.64	-1.3%
GS>50 kW Non-RPP	44,300	139	$ 7,056.66	$ 6,959.28	-$ 97.38	-1.4%
USL	800		$ 172.40	$ 120.72	-$ 51.69	-30.0%
Sentinel Lighting	300	5	$ 79.43	$ 88.67	$ 9.24	11.6%
Street Lighting	46,000	129	$ 12,156.51	$ 11,381.00	-$ 775.51	-6.4%
Street Lighting Non-RPP	46,000	129	$ 12,767.30	$ 12,111.69	-$ 655.61	-5.1%

Selected Delivery Charge and Bill Impacts Per Application
Port Colborne

Customer Classification and Billing Type	Energy kWh	Demand kW	Monthly Delivery Charge			
			Current	Per Application	Change $	Change %
Residential	800		$ 49.29	$ 46.20	-$ 3.09	-6.3%
Residential Non-RPP	800		$ 56.97	$ 53.88	-$ 3.09	-5.4%
GS<50 kW	2,000		$ 95.60	$ 98.87	$ 3.27	3.4%
GS<50 kW Non-RPP	2,000		$ 114.80	$ 118.07	$ 3.27	2.8%
GS>50 kW	102,500	330	$ 3,015.26	$ 3,587.66	$ 572.40	19.0%
GS>50 kW Non-RPP	102,500	330	$ 3,849.13	$ 4,421.53	$ 572.40	14.9%
USL	800		$ 78.79	$ 44.27	-$ 34.52	-43.8%
Sentinel Lighting	300	5	$ 69.43	$ 57.46	-$ 11.98	-17.3%
Street Lighting	155,000	445	$ 13,259.50	$ 15,488.49	$ 2,228.98	16.8%
Street Lighting Non-RPP	155,000	445	$ 14,278.87	$ 17,027.70	$ 2,748.83	19.3%

Customer Classification and Billing Type	Energy kWh	Demand kW	Total Bill			
			Current	Per Application	Change $	Change %
Residential	800		$ 126.15	$ 123.01	-$ 3.14	-2.5%
Residential Non-RPP	800		$ 147.61	$ 144.12	-$ 3.49	-2.4%
GS<50 kW	2,000		$ 301.85	$ 305.18	$ 3.33	1.1%
GS<50 kW Non-RPP	2,000		$ 337.46	$ 341.16	$ 3.70	1.1%
GS>50 kW	102,500	330	$ 14,040.32	$ 14,622.45	$ 582.13	4.1%
GS>50 kW Non-RPP	102,500	330	$ 14,983.03	$ 15,629.84	$ 646.81	4.3%
USL	800		$ 156.15	$ 121.04	-$ 35.11	-22.5%
Sentinel Lighting	300	5	$ 99.90	$ 87.72	-$ 12.18	-12.2%
Street Lighting	155,000	445	$ 30,592.65	$ 32,859.53	$ 2,266.88	7.4%
Street Lighting Non-RPP	155,000	445	$ 32,779.64	$ 35,885.82	$ 3,106.18	9.5%

(VECC)

9. Rate Harmonization

9.2 Is the combined cost allocation supporting CNPI's proposed phase-in rate harmonization appropriate?

33. Reference: Exhibit 7, Tab 3, Schedule 1, pages 1 – 3
Exhibit 8, Tab 4, Schedule 1, pages 4 - 5

a) Given CNPI's plan to harmonize rates across its entire service territory, please explain why the Cost Allocation results based on the entire service area were not used as the starting point in considering the adjustments necessary to revenue to cost ratios. (Note: This question and the following questions are also related to both Issue 7.3 and 7.4)

b) Based on the full service territory cost allocation (per the second reference), please confirm that only the ratios for the USL and Sentinel Lighting classes are outside the Board's policy ranges for the various customer classes.

c) Please explain how the proposed ratios in Appendix 2-O in the first reference were determined. Are they derived values based on the revenues that result for the separate revenue to cost ratio adjustments proposed for the FE/EOP and PC service areas?

d) With respect to the second reference, please explain how the "Target Revenue to Cost Ratios" in the table (e.g. Residential – 91.00 % and GS<50 – 116.03%) were determined.

e) With respect to the second reference, please provide resulting cost ratios for Residential and Sentinel Lighting based on the following adjustments to the full service territory revenue to cost ratios:
- Leave GS<50, GS>50 and Street Lighting unchanged from Status Quo
- Adjust USL as proposed
- Offset the revenue shortfall by first increasing Sentinel Lighting ratio until it reaches 91.27% and then increase both it and the Residential ratios in tandem.

RESPONSE:

a) CNPI's guiding principle is fairness to rate payers by consideration of the burden of distribution rate impact and total bill impact. The starting point is current Board approved rates. The bill impact of getting from these rates to the designed rates is the measure of practicality. It is CNPI's view that it is not practical to move from the electricity distribution rates that are currently in effect to harmonized rates today (for all rate classifications) that could satisfy a reasonable total bill impact test.

b) Confirmed.

c) Yes.

d) The "Target Revenue to Cost Ratios" is the weighted average of Fort Erie/Gananoque and Port Colborne. The weighting is based on each service areas contribution to revenue requirement.

e) Please see table below:

Setting Target Revenue to Cost Ratios

Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Taget Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	12,176,206	887,433	10,226,386	91.47%	10,250,175
GS Less Than 50 kW	2,442,261	171,802	2,499,053	109.36%	2,499,055
GS 50 to 4,999 kW	4,231,471	297,612	4,746,987	119.22%	4,747,148
USL	38,075	3,257	96,070	170.55%	61,680
Sentinel Lighting	85,181	5,731	61,751	91.47%	72,184
Street Lighting	521,249	37,349	461,011	95.61%	461,017
Total	$ 19,494,443	$ 1,403,184	$18,091,258		$ 18,091,258

Canadian Niagara Power Inc.

EB-2012-0112

Response to Deferral and Variance Accounts Interrogatories

10. Deferral and Variance Accounts

10.1
Are the account balances, cost allocation methodology and disposition period appropriate?

(OEB)

Deferral and Variance Accounts

Issue 10.1
Are the account balances, cost allocation methodology and disposition period appropriate?

66. Ref: E9/T1/S1/P9; S.2.12.1 and; S.2.12.2 of Chapter 2 of the Filing Guidelines for Electricity Distributors

CNPI is requesting the disposition of Account 1592, PILS & Tax Variance, sub-account HST/OVAT Input Tax Credits balance as at December 31, 2011 plus forecasted interest to December 31, 2012 for Fort Erie, EOP and Port Colborne.

CNPI did not file Appendix 2-T for Account 1592 as prescribed by the S.2.12.2 of Chapter 2 of the Filing Guidelines.

a) Please confirm that the three utilities above do not intend to continue to use the above sub-account of Account 1592 for the Test Year and going forward. If this is not the case, please explain.
b) Please complete and file Appendix 2-T for the three service areas.

RESPONSE:

a) CNPI confirms that is does not intend to continue to use the sub-account (i.e. HST/OVAT) of Account 1592 for the Test Year and going forward.

b) CNPI has not completed Appendix 2-T for each of the services territories and proposes to complete them for the 2014 IRM application.

10. Deferral and Variance Accounts

10.2
Are the proposed rate riders to dispose of the account balances appropriate?

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

67.10.2 Ref: Continuity Schedules - PILs Recoveries from Ratepayers

Most distributors have higher PILs recoveries from ratepayers than the PILs proxies because of customer and load growth since 2001. CNPI's evidence shows this same trend except for Port Colborne in 2004. Please explain why the recoveries from customers in 2004 were lower than the PILs proxy.

RESPONSE:

CNPI-PC is not specifically aware why the recoveries from the customers in 2004 were lower than the PILS proxy. There has not been consistent growth in the Port Colborne service territory and there has been some volatility based on large customer usage and the timing of temporary boats tying up at year end in the Welland Canal.

Also, CNPI-PC had previously not always properly accounted for unbilled revenue projections at year end given the very temporary nature of service being provided to boats in the Welland Canal. Often the connections occur late in the year or at the beginning of the year. These connections mean a significant demand and consumption may occur over a very short period. The recognition of revenue between years is sometimes impacted.

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

68. Ref: Continuity Schedules - PILs Recoveries from Ratepayers

The unbilled revenue as at April 30, 2006 may have been difficult to determine. Many distributors provided billing statistics for the months that followed April 2006 as a way of demonstrating how much PILs was related to demand and energy consumed before May 1, 2006 but billed afterwards.

> For each of the three service areas, please provide tables that show the customer dollar billings and the billing determinants (kW, kWh) by customer class for the months of May, June and July 2006. Please calculate the PILs amount by multiplying the billing determinants by the PILs rate slivers by class for May through July 2006.

RESPONSE:

For purposes of bill determination and revenue recognition upon rate changes CNP follows the traditional LDC practice of prorating both the fixed and variable charges based on the number of days at old and new rates. However, the billing system is not capable of breaking down customer class monthly billed quantities between consumption at old and new rates.

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

69. Ref: Continuity Schedules - PILs Recoveries from Ratepayers

In each of the continuity schedules for the three service areas, Board staff noticed that the fixed charge recovery in March 2004 was pro-rated by 50%. It seems to Board staff that energy and demand might be pro-rated but that the customers would have been billed the fixed charges on the invoices issued in March and in April.

Please verify the formulae used in the calculations of recoveries to ensure that the dollar amounts are correct and state the outcome of the review.

RESPONSE:

The fixed charge recovery was prorated by 50% at the beginning of the period as well. The 50% proration at both the beginning and end of the period would result in total PILS recoveries from the fixed charge being very close to fixed charge recoveries using actual billed quantities for the month.

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

70. Ref: Continuity Schedules - PILs Recoveries from Ratepayers

Please file the 2001 Board decision and rate Order for Fort Erie.

RESPONSE:

Attached is the approved CNPI – Fort Erie's Schedule of Rates and Charges (effective January 1, 2002) based on the Board's Decision dated December 11, 2001 (PILS Binder - Exhibit 2 Tab 3 Schedule 3)

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

71. Ref: SIMPIL Models – Interest Expense for Tax Years 2001 to 2005

For each of the three service areas, or for the combined CNPI distribution total if that is easier, for the tax years 2001 to 2005:

a) Please provide a table for the years that shows all of the components of CNPI's interest expense and the amount associated with each type of interest.

b) Did CNPI have interest expense related to other than debt that is disclosed as interest expense in its financial statements?

c) Did CNPI net interest income against interest expense in deriving the amount it shows as interest expense? If yes, please provide details to what the interest income relates.

d) Did CNPI include interest expense on customer security deposits in interest expense?

e) Did CNPI include interest income on customer security deposits in interest expense?

f) Did CNPI include interest expense on IESO prudentials in interest expense? Please provide the dollar amount of IESO or other prudential expense by year whether disclosed as interest, admin, or other type of expense category.

g) Did CNPI include interest carrying charges on regulatory assets or liabilities in interest expense?

h) Did CNPI include the amortization of debt issue costs, debt discounts or debt premiums in interest expense?

i) Did CNPI deduct capitalized interest in deriving the interest expense disclosed in its financial statements?

RESPONSE:

a)

Interest Expense
CNPI - FE, EOP and PC

	2001	2002	2003	2004	2005
Loan Interest Expense - Affiliate	546,164	788,637	502,343		177,509
Overdraft Interest	250		34,438	179	569
Interest on Tax Assessments	(1,342)	208	6,150	28,012	186
Interest on floating loans	(3,396)		2,250	8,911	9,013
Interest on loan			392,969	1,138,266	1,138,266
Amortized Setup Fees			13,345	32,028	32,028
Capitalized interest	(198,592)	(18,692)	(5,956)	(64,731)	(15,719)
Total Interest	343,083	770,152	945,538	1,142,666	1,341,852

b) Did CNPI have interest expense related to other than debt that is disclosed as interest expense in its financial statements?

RESPONSE: In addition to interest expense on loans from affiliates or third parties the following are included in the interest expense total:

Overdraft interest on bank overdrafts
Interest on tax assessments
Amortization of finance costs
Capitalized interest

.

c) Did CNPI net interest income against interest expense in deriving the amount it shows as interest expense? If yes, please provide details to what the interest income relates.

RESPONSE: No, CNPI did not net interest income against interest expense.

.

d) Did CNPI include interest expense on customer security deposits in interest expense?

RESPONSE: No, for those years the interest expense on customer security deposits was grouped with customer service under administration expense.

e) Did CNPI include interest income on customer security deposits in interest expense?

RESPONSE: See response to item d) above.

f) Did CNPI include interest expense on IESO prudentials in interest expense? Please provide the dollar amount of IESO or other prudential expense by year whether disclosed as interest, admin, or other type of expense category.

RESPONSE: CNPI did not include the IESO prudentials cost in interest expenses; rather it was grouped as an administration cost.

The following summarizes the prudential cost by LDC by year:

Fort Erie 2002 - $10,632.84

2003 - $10,537.84
2004 - $10,537.84
2005 - $10,537.84

Port Colborne 2002 - $7,042.17
2003 - $6,967.17
2004 - $6,967.17
2005 - $6,967.17

g) Did CNPI include interest carrying charges on regulatory assets or liabilities in interest expense?

RESPONSE: No, CNPI did not record interest carrying charges on regulatory assets or liabilities in interest expense.

h) Did CNPI include the amortization of debt issue costs, debt discounts or debt premiums in interest expense?

RESPONSE: Yes, CNPI did deduct the amortization of debt issue costs in interest expense.

i) Did CNPI deduct capitalized interest in deriving the interest expense disclosed in its financial statements?

RESPONSE: Yes, CNPI did deduct capitalized interest in deriving the interest expense disclosed in its financial statements.

(OEB)

Deferral and Variance Accounts

Issue 10.2
Are the proposed rate riders to dispose of the account balances appropriate?

72. Ref: SIMPIL Models – Income Tax Rates

The income tax rates used in Port Colborne's 2001 SIMPIL model are not consistent with the statements in the Overview Exh.1/Tab1/Sch.1/page 3 or with page 17 of the Board's decision in the combined proceeding EB-2008-0381. The tax rate entered in SIMPIL is not the same as appears in the 2001 PILs proxy model. The line item amounts are not the same as those amounts entered in the 2001 PILs proxy worksheet. Please verify the numbers in the 2001 SIMPIL with the 2001 PILs proxy and make corrections where required.

RESPONSE:

CNPI has revised the component pieces of the 2001 SIMPILS model to reconcile to the component pieces of the approved 2001 PILS determination model. The revised SIMPILS model is attached.

The revisions have resulted in a change in the true-up from the original filed amount of $12,368 due to customers to a debit balance of $3,704 receivable from customers. The revised continuity schedule is attached.

Canadian Niagara Power - Port Colbourne

1562 Deferred PILS - Continuity Schedule

Year: Q4 2001

	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
October	$ 42,832.67	$ -		$ 42,832.67	$ 42,832.67	7.25%	$ -	$ -	$ 42,832.67
November	$ 42,832.67	$ -		$ 42,832.67	$ 85,665.33	7.25%	$ 258.78	$ 258.78	$ 85,924.11
December	$ 42,832.67	$ -		$ 42,832.67	$ 128,498.00	7.25%	$ 517.56	$ 776.34	$ 129,274.34
Total	$ 128,498.00	$ -	$ -	$ 128,498.00			$ 776.34		

Year: 2002

	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January	$ 42,532.42	$ -		$ 42,532.42	$ 171,030.42	7.25%	$ 776.34	$ 1,552.68	$ 172,583.10
February	$ 42,532.42	$ -		$ 42,532.42	$ 213,562.83	7.25%	$ 1,033.31	$ 2,585.99	$ 216,148.83
March	$ 42,532.42	$ 25,369.88		$ 17,162.54	$ 230,725.37	7.25%	$ 1,290.28	$ 3,876.27	$ 234,601.64
April	$ 42,532.42	$ 51,940.86		-$ 9,408.44	$ 221,316.93	7.25%	$ 1,393.97	$ 5,270.23	$ 226,587.17
May	$ 42,532.42	$ 53,659.18		-$ 11,126.77	$ 210,190.17	7.25%	$ 1,337.12	$ 6,607.36	$ 216,797.52
June	$ 42,532.42	$ 56,064.13		-$ 13,531.72	$ 196,658.45	7.25%	$ 1,269.90	$ 7,877.26	$ 204,535.70
July	$ 42,532.42	$ 60,128.99	$ 3,704.00	-$ 13,892.57	$ 182,765.88	7.25%	$ 1,188.14	$ 9,065.40	$ 191,831.28
August	$ 42,532.42	$ 58,842.20		-$ 16,309.79	$ 166,456.09	7.25%	$ 1,104.21	$ 10,169.61	$ 176,625.71
September	$ 42,532.42	$ 53,874.68		-$ 11,342.26	$ 155,113.83	7.25%	$ 1,005.67	$ 11,175.28	$ 166,289.12
October	$ 42,532.42	$ 51,398.21		-$ 8,865.80	$ 146,248.04	7.25%	$ 937.15	$ 12,112.43	$ 158,360.47
November	$ 42,532.42	$ 53,480.85		-$ 10,948.43	$ 135,299.61	7.25%	$ 883.58	$ 12,996.01	$ 148,295.62
December	$ 42,532.42	$ 51,427.78		-$ 8,895.37	$ 126,404.24	7.25%	$ 817.44	$ 13,813.45	$ 140,217.69
Total	$ 510,389.00	$ 516,186.76	$ 3,704.00	-$ 2,093.76			$ 13,037.10		

Year: 2003

	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January	$ 53,240.58	$ 56,904.77		-$ 3,664.19	$ 122,740.06	7.25%	$ 763.69	$ 14,577.14	$ 137,317.19
February	$ 53,240.58	$ 56,048.35		-$ 2,807.76	$ 119,932.29	7.25%	$ 741.55	$ 15,318.69	$ 135,250.99
March	$ 53,240.58	$ 55,722.00		-$ 2,481.41	$ 117,450.88	7.25%	$ 724.59	$ 16,043.28	$ 133,494.16
April	$ 53,240.58	$ 56,661.93		-$ 3,421.35	$ 114,029.53	7.25%	$ 709.60	$ 16,752.88	$ 130,782.41
May	$ 53,240.58	$ 46,079.01		$ 7,161.57	$ 121,191.10	7.25%	$ 688.93	$ 17,441.81	$ 138,632.91
June	$ 53,240.58	$ 53,231.98		$ 8.61	$ 121,199.71	7.25%	$ 732.20	$ 18,174.01	$ 139,373.71
July	$ 53,240.58	$ 59,405.32	-$ 93,986.00	-$ 100,150.74	$ 21,048.97	7.25%	$ 732.25	$ 18,906.26	$ 39,955.23
August	$ 53,240.58	$ 58,726.14		-$ 5,485.55	$ 15,563.42	7.25%	$ 127.17	$ 19,033.43	$ 34,596.84
September	$ 53,240.58	$ 56,572.07		-$ 3,331.49	$ 12,231.93	7.25%	$ 94.03	$ 19,127.46	$ 31,359.38
October	$ 53,240.58	$ 55,646.17		-$ 2,405.58	$ 9,826.34	7.25%	$ 73.90	$ 19,201.36	$ 29,027.70
November	$ 53,240.58	$ 55,088.28		-$ 1,847.69	$ 7,978.65	7.25%	$ 59.37	$ 19,260.73	$ 27,239.37
December	$ 53,240.58	$ 55,834.56		-$ 2,593.98	$ 5,384.67	7.25%	$ 48.20	$ 19,308.93	$ 24,693.60
Total	$ 638,887.00	$ 665,920.57	-$ 93,986.00	-$ 121,019.57			$ 5,495.48		

Year: 2004

	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January	$ 53,240.58	$ 57,707.35		-$ 4,466.76	$ 917.91	7.25%	$ 32.53	$ 19,341.46	$ 20,259.37
February	$ 53,240.58	$ 53,786.06		-$ 545.48	$ 372.43	7.25%	$ 5.55	$ 19,347.01	$ 19,719.44
March	$ 53,240.58	$ 45,970.29		$ 7,270.29	$ 7,642.72	7.25%	$ 2.25	$ 19,349.26	$ 26,991.98
April	$ 42,532.42	$ 35,474.87		$ 7,057.54	$ 14,700.27	7.25%	$ 46.17	$ 19,395.43	$ 34,095.70
May	$ 42,532.42	$ 36,348.80		$ 6,183.62	$ 20,883.88	7.25%	$ 88.81	$ 19,484.25	$ 40,368.13
June	$ 42,532.42	$ 39,909.63		$ 2,622.78	$ 23,506.67	7.25%	$ 126.17	$ 19,610.42	$ 43,117.09
July	$ 42,532.42	$ 43,123.94	-$ 95,413.00	-$ 96,004.53	-$ 72,497.86	7.25%	$ 142.02	$ 19,752.44	-$ 52,745.42
August	$ 42,532.42	$ 42,220.11		$ 312.31	-$ 72,185.55	7.25%	-$ 438.01	$ 19,314.43	-$ 52,871.12
September	$ 42,532.42	$ 42,119.22		$ 413.19	-$ 71,772.36	7.25%	-$ 436.12	$ 18,878.31	-$ 52,894.05
October	$ 42,532.42	$ 38,551.15		$ 3,981.27	-$ 67,791.09	7.25%	-$ 433.62	$ 18,444.69	-$ 49,346.41
November	$ 42,532.42	$ 40,550.24		$ 1,982.18	-$ 65,808.91	7.25%	-$ 409.57	$ 18,035.11	-$ 47,773.80
December	$ 42,532.42	$ 43,901.54		-$ 1,369.12	-$ 67,178.04	7.25%	-$ 397.60	$ 17,637.52	-$ 49,540.52
Total	$ 542,513.50	$ 519,663.21	-$ 95,413.00	-$ 72,562.71			-$ 1,671.41		

Year:	2005			Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January	$ 42,532.42	$ 49,894.69		-$ 7,362.27	-$ 74,540.31	7.25%	-$ 405.87	$ 17,231.65	-$ 57,308.66
February	$ 42,532.42	$ 46,303.47		-$ 3,771.05	-$ 78,311.36	7.25%	-$ 450.35	$ 16,781.30	-$ 61,530.05
March	$ 42,532.42	$ 37,237.68		$ 5,294.73	-$ 73,016.62	7.25%	-$ 473.13	$ 16,308.17	-$ 56,708.45
April	$ 24,960.58	$ 24,711.25		$ 249.33	-$ 72,767.29	7.25%	-$ 441.14	$ 15,867.03	-$ 56,900.26
May	$ 24,960.58	$ 23,896.88		$ 1,063.71	-$ 71,703.58	7.25%	-$ 439.64	$ 15,427.40	-$ 56,276.19
June	$ 24,960.58	$ 27,955.73		-$ 2,995.14	-$ 74,698.73	7.25%	-$ 433.21	$ 14,994.19	-$ 59,704.54
July	$ 24,960.58	$ 32,233.51	-$ 141,462.00	-$ 148,734.93	-$ 223,433.66	7.25%	-$ 451.30	$ 14,542.88	-$ 208,890.78
August	$ 24,960.58	$ 31,951.52		-$ 6,990.94	-$ 230,424.59	7.25%	-$ 1,349.91	$ 13,192.97	-$ 217,231.63
September	$ 24,960.58	$ 27,633.56		-$ 2,672.97	-$ 233,097.57	7.25%	-$ 1,392.15	$ 11,800.82	-$ 221,296.75
October	$ 24,960.58	$ 25,401.66		-$ 441.07	-$ 233,538.64	7.25%	-$ 1,408.30	$ 10,392.52	-$ 223,146.12
November	$ 24,960.58	$ 26,482.68		-$ 1,522.09	-$ 235,060.73	7.25%	-$ 1,410.96	$ 8,981.56	-$ 226,079.17
December	$ 24,960.58	$ 29,272.30		-$ 4,311.71	-$ 239,372.45	7.25%	-$ 1,420.16	$ 7,561.40	-$ 231,811.05
Total	$ 352,242.50	$ 382,974.91	-$ 141,462.00	-$ 172,194.41			-$ 10,076.12		

Year:	2006			Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January	$ 24,960.58	$ 27,813.03		-$ 2,852.44	-$ 242,224.89	7.25%	-$ 1,446.21	$ 6,115.19	-$ 236,109.70
February	$ 24,960.58	$ 27,501.61		-$ 2,541.03	-$ 244,765.92	7.25%	-$ 1,463.44	$ 4,651.75	-$ 240,114.17
March	$ 24,960.58	$ 27,887.68		-$ 2,927.10	-$ 247,693.02	7.25%	-$ 1,478.79	$ 3,172.96	-$ 244,520.06
April	$ 24,960.58	$ 23,209.53		$ 1,751.05	-$ 245,941.97	7.25%	-$ 1,496.48	$ 1,676.48	-$ 244,265.49
May		$ 12,106.44		-$ 12,106.44	-$ 258,048.40	4.14%	-$ 848.50	$ 827.98	-$ 257,220.42
June				$ -	-$ 258,048.40	4.14%	-$ 890.27	-$ 62.29	-$ 258,110.69
July			$ 55,469.00	$ 55,469.00	-$ 202,579.40	4.59%	-$ 987.04	-$ 1,049.32	-$ 203,628.73
August				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 1,824.19	-$ 204,403.59
September				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 2,599.06	-$ 205,178.46
October				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 3,373.92	-$ 205,953.33
November				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 4,148.79	-$ 206,728.19
December				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 4,923.65	-$ 207,503.06
Total	$ 99,842.33	$ 118,518.29	$ 55,469.00	$ 36,793.04			-$ 12,485.06		

Year:	2007			Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	SIMPILS True-Up Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 5,698.52	-$ 208,277.92
February				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 6,473.39	-$ 209,052.79
March				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 7,248.25	-$ 209,827.66
April				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 8,023.12	-$ 210,602.52
May				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 8,797.99	-$ 211,377.39
June				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 9,572.85	-$ 212,152.26
July				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 10,347.72	-$ 212,927.12
August				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 11,122.58	-$ 213,701.99
September				$ -	-$ 202,579.40	4.59%	-$ 774.87	-$ 11,897.45	-$ 214,476.85
October				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 12,765.17	-$ 215,344.57
November				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 13,632.88	-$ 216,212.28
December				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 14,500.60	-$ 217,080.00
Total	$ -	$ -	$ -	$ -			-$ 9,576.94		

Year:	2008									
			SIMPILS True-Up	Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 15,368.31	-$ 217,947.71
February				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 16,236.03	-$ 218,815.43
March				$ -	-$ 202,579.40	5.14%	-$ 867.72	-$ 17,103.74	-$ 219,683.14
April				$ -	-$ 202,579.40	4.08%	-$ 688.77	-$ 17,792.51	-$ 220,371.91
May				$ -	-$ 202,579.40	4.08%	-$ 688.77	-$ 18,481.28	-$ 221,060.68
June				$ -	-$ 202,579.40	4.08%	-$ 688.77	-$ 19,170.05	-$ 221,749.45
July				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 19,735.59	-$ 222,314.99
August				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 20,301.12	-$ 222,880.52
September				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 20,866.65	-$ 223,446.06
October				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 21,432.19	-$ 224,011.59
November				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 21,997.72	-$ 224,577.13
December				$ -	-$ 202,579.40	3.35%	-$ 565.53	-$ 22,563.26	-$ 225,142.66
Total	$ -	$ -	$ -	$ -			-$ 8,062.66		

Year:	2009									
			SIMPILS True-Up	Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	2.45%	-$ 413.60	-$ 22,976.86	-$ 225,556.26
February				$ -	-$ 202,579.40	2.45%	-$ 413.60	-$ 23,390.46	-$ 225,969.86
March				$ -	-$ 202,579.40	2.45%	-$ 413.60	-$ 23,804.05	-$ 226,383.46
April				$ -	-$ 202,579.40	1.00%	-$ 168.82	-$ 23,972.87	-$ 226,552.27
May				$ -	-$ 202,579.40	1.00%	-$ 168.82	-$ 24,141.69	-$ 226,721.09
June				$ -	-$ 202,579.40	1.00%	-$ 168.82	-$ 24,310.50	-$ 226,889.91
July				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,403.35	-$ 226,982.76
August				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,496.20	-$ 227,075.60
September				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,589.05	-$ 227,168.45
October				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,681.90	-$ 227,261.30
November				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,774.75	-$ 227,354.15
December				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,867.60	-$ 227,447.00
Total	$ -	$ -	$ -	$ -			-$ 2,304.34		

Year:	2010									
			SIMPILS True-Up	Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 24,960.45	-$ 227,539.85
February				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 25,053.29	-$ 227,632.70
March				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 25,146.14	-$ 227,725.55
April				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 25,238.99	-$ 227,818.40
May				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 25,331.84	-$ 227,911.24
June				$ -	-$ 202,579.40	0.55%	-$ 92.85	-$ 25,424.69	-$ 228,004.09
July				$ -	-$ 202,579.40	0.89%	-$ 150.25	-$ 25,574.94	-$ 228,154.34
August				$ -	-$ 202,579.40	0.89%	-$ 150.25	-$ 25,725.18	-$ 228,304.59
September				$ -	-$ 202,579.40	0.89%	-$ 150.25	-$ 25,875.43	-$ 228,454.83
October				$ -	-$ 202,579.40	1.20%	-$ 202.58	-$ 26,078.01	-$ 228,657.41
November				$ -	-$ 202,579.40	1.20%	-$ 202.58	-$ 26,280.59	-$ 228,859.99
December				$ -	-$ 202,579.40	1.20%	-$ 202.58	-$ 26,483.17	-$ 229,062.57
Total	$ -	$ -	$ -	$ -			-$ 1,615.57		

Year:	2011								
			SIMPILS True-Up	Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 26,731.33	-$ 229,310.73
February				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 26,979.49	-$ 229,558.89
March				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 27,227.65	-$ 229,807.05
April				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 27,475.81	-$ 230,055.21
May				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 27,723.97	-$ 230,303.37
June				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 27,972.13	-$ 230,551.53
July				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 28,220.29	-$ 230,799.69
August				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 28,468.45	-$ 231,047.85
September				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 28,716.61	-$ 231,296.01
October				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 28,964.77	-$ 231,544.17
November				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 29,212.92	-$ 231,792.33
December				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 29,461.08	-$ 232,040.49
Total	$ -	$ -	$ -	$ -			-$ 2,977.92		

Year:	2012								
			SIMPILS True-Up	Variance (neg. = payable)		Interest Improvement (neg = payable)			
	Approved PILS Entitlement	PILS Revenue	Adjustments (neg = CR)	Monthly	Cumulative	Approved Interest Rate	Monthly	Cumulative	Total Variance
January				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 29,709.24	-$ 232,288.65
February				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 29,957.40	-$ 232,536.81
March				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 30,205.56	-$ 232,784.97
April				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 30,453.72	-$ 233,033.13
May				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 30,701.88	-$ 233,281.29
June				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 30,950.04	-$ 233,529.45
July				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 31,198.20	-$ 233,777.61
August				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 31,446.36	-$ 234,025.77
September				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 31,694.52	-$ 234,273.93
October				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 31,942.68	-$ 234,522.09
November				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 32,190.84	-$ 234,770.25
December				$ -	-$ 202,579.40	1.47%	-$ 248.16	-$ 32,439.00	-$ 235,018.41
Total	$ -	$ -	$ -	$ -			-$ 2,977.92		

Canadian Niagara Power Inc.

EB-2012-0112

Response to Accounting Standards for Private Enterprise ("ASPE") Interrogatories

11. Accounting Standards for Private Enterprise ("ASPE")

11.1
Are the proposed Revenue Requirements determined using ASPE appropriate?

(SEC)

11. Accounting Standards for Private Enterprise ("ASPE")
11.1 Is the use of Accounting Standards for Private Enterprise ("ASPE") appropriate for the purpose of CNPI's distribution rate application?

22. [Ex.11/1]
Please outline all actual and potential differences between the calculation of the following metrics, contained in the OEB Yearbook, under modified IFRS and under the Applicant's proposed adoption of ASPE:

a) Property plant & equipment
b) Accumulated depreciation & amortization
c) Operating expenses
d) Administration expenses
e) Maintenance expenses

RESPONSE:

a), b), c), d), & e)

Please refer to page 2.

The company adopted ASPE effective Jan 1, 2010 (the transition date).
The company is not adopting IFRS, it is proposing to change its capitalization policy and depreciation rates in order to conform with IAS 16 and the Board's direction on MIFRS.

The following table outlines the differences between MIFRS and proposed ASPE (including proposed accounting change).

	MIFRS	**Proposed ASPE**
Property, Plant & Equipment	Non-attributable costs are not capitalized Vehicle depreciation is capitalized See E11 T1 S9	Non-attributable costs are not capitalized Vehicle depreciation is capitalized See E11 T1 S9
Accumulated depreciation & amortization	Depreciation expense will be lower due to change in useful lives and change in amounts capitalized See response to OEB #25	Depreciation expense will be lower due to change in useful lives and change in amounts capitalized See response to OEB #25
Operating expenses	Will Increase by non-attributable costs not capitalized See response to OEB #25	Will Increase by non-attributable costs not capitalized See response to OEB #25
Administrative expenses	Will Increase by non-attributable costs not capitalized See response to OEB #25	Will Increase by non-attributable costs not capitalized See response to OEB #25
Maintenance expenses	Will Increase by non-attributable costs not capitalized See response to OEB #25	Will Increase by non-attributable costs not capitalized See response to OEB #25

CNPI is not aware of any difference in the metrics under MIFRS or proposed ASPE.

(SEC)

11. Accounting Standards for Private Enterprise ("ASPE")
11.1 Is the use of Accounting Standards for Private Enterprise ("ASPE") appropriate for the purpose of CNPI's distribution rate application?

23. [RRWF]
As a result of this interrogatory process, if any changes are made to inputs required for the Revenue Requirement Work form (RRWF), please provide an updated copy of the RRWF and an itemized list of changes and their corresponding revenue requirement impacts.

RESPONSE:

Please see the responses to Board Staff interrogatories #3 and #4.

11. Accounting Standards for Private Enterprise (“ASPE”)

11.2
Is the proposed change in accounting policy regarding the capitalization of overhead costs appropriate?

(OEB)

Accounting Standards for Private Enterprise ("ASPE")

Issue 11.2 Are the proposed Revenue Requirements determined using ASPE appropriate?

73. Ref: E11/T1/S3/p.1 (Table 1) & p.2 (Table 2); E2/T1/S5/p.5; E2/T1/S57/p.5; E11/T1/S5/p.1; E11/T1/S6/p.1; E11/T1/S7/p.1; E4/T7/S2/p.5 and E4/T7/S3/p.5

Tables 1 and 2 below present the impact of selected items like OM&A to the rate base and to the revenue requirement under CGAAP and MIFRS for CNPI (total for FE/EOP and PC).

Table 1
Impact to Rate Base

RATE BASE	CGAAP $000			MIFRS $000		
	FE AND EOP	PC	FE, EOP AND PC	FE AND EOP	PC	FE, EOP AND PC
2012 Net Fixed Assets	$ 45,851	$ 17,154	$ 63,005	$ 45,851	$ 17,154	$ 63,005
2013 Net Fixed Assets	$ 49,478	$ 19,003	$ 68,481	$ 49,476	$ 18,810	$ 68,285
Average Net Fixed Assets	$ 47,665	$ 18,078	$ 65,743	$ 47,664	$ 17,982	$ 65,645
Cost of Power	$ 32,673	$ 17,574	$ 50,247	$ 32,673	$ 17,574	$ 50,247
OM&A	$ 5,908	$ 2,836	$ 8,745	$ 6,706	$ 3,180	$ 9,886
Working Capital Requirement @ 13%	$ 5,016	$ 2,653	$ 7,669	$ 5,119	$ 2,698	$ 7,817
Rate Base	$ 52,680	$ 20,732	$ 73,412	$ 52,783	$ 20,680	$ 73,462
Increase in Rate Base				$ 103	$ (52)	$ 50

Table 2
Impact to Revenue Requirement

REVENUE REQUIREMENT	CGAAP $000			MIFRS $000		
	FE AND EOP	PC	FE, EOP AND PC	FE AND EOP	PC	FE, EOP AND PC
OM&A	$ 5,908	$ 2,836	$ 8,745	$ 6,706	$ 3,180	$ 9,886
Depreciation	$ 2,996	$ 1,427	$ 4,423	$ 2,262	$ 1,261	$ 3,523
Return on Capital @ 7.41%	$ 3,904	$ 1,536	$ 5,440	$ 3,911	$ 1,532	$ 5,444
Income taxes	$ 400	$ 158	$ 558	$ 461	$ 181	$ 642
Service Revenue Requirement	$ 13,208	$ 5,957	$ 19,165	$ 13,340	$ 6,155	$ 19,494
Revenue Offsets	$ (1,132)	$ (271)	$ (1,403)	$ (1,132)	$ (271)	$ (1,403)
Base Revenue Requirement	$ 12,076	$ 5,686	$ 17,762	$ 12,208	$ 5,883	$ 18,091
Increase in Revenue Requirement				$ 131	$ 197	$ 329

a) In Table 1 above, please explain why the 2013 net fixed assets for FE/EOP and PC are almost the same under CGAAP and MIFRs given that CNPI is no longer capitalizing overhead and has updated its depreciation rates based on the Kinectrics study.
b) Please make all the adjustments if any, to the proper schedules to reflect the correct amounts for net fixed assets for 2012 and 2013 for FE and EOP for part a.
c) The depreciation expenses in Table 2 above, under MIFRS for FE/EOP and PC are different from the depreciation in E11/T1/S5/P1 and under the "Additions" column in E11/T1/S6/P1 and the depreciation expense in E4/T7/S2/P5 for FE/EOP and E11/T1/S7/P1 and E4/T7/S3/P5 for PC. Please explain why.
d) Please make adjustments if any, to the proper schedules to reflect the correct amounts for FE/EOP and PC.

RESPONSE:

a) The 2013 net fixed assets are almost the same under CGAAP and MIFRS because the GEC and the change in depreciation expense are almost equal. See table below.

	FE AND EOP	PC
2013 Net Fixed Assets - CGAAP	49,478	19,003
GEC - non-attributable	(760)	(352)
Change in depreciation expense (1)	700	182
Change in depreciation expense re allocations (1)	60	(16)
rounding	(2)	(7)
2013 Net Fixed Assets - MIFRS	49,476	18,810

(1) See Appendix 2-CG in OEB #5

b) No adjustments are required.

c) See the reconciliations of depreciation expense in the responses to Board Staff interrogatory #5, Appendix 2-CG and Board Staff interrogatory #25, Appendix 2-M.

There is an error in the FE and EOP 2013 MIFRS depreciation expense due to the pre 1999 CIAC depreciation expense of $25,505 that was not deducted. The 2013 MIFRS depreciation expense for FE and EOP should be $2,236,237.

d) The following schedules are attached and have been adjusted for the 2013 MIFRS depreciation expense for FE and EOP:

Exhibit 11 Tab 1 Schedule 3 pg 2 Table 2
Exhibit 11 Tab 1 Schedule 11 – Revenue Deficiency MIFRS

Exhibit 11 Tab 1 Schedule 12 – Revenue Deficiency Test Year MIFRS

Exhibit 11 Tab 1 Schedule 13 – RRWF FE and EOP

Exhibit 11 Tab 1 Schedule 15 - RRWF FE, EOP and PC

Table 2
Impact to Revenue Requirement

REVENUE REQUIREMENT	CGAAP $000			MIFRS $000		
	FE AND EOP	PC	FE, EOP AND PC	FE AND EOP	PC	FE, EOP AND PC
OM&A	$ 5,908	$ 2,836	$ 8,745	$ 6,706	$ 3,180	$ 9,886
Depreciation	$ 2,996	$ 1,427	$ 4,423	$ 2,236	$ 1,261	$ 3,497
Return on Capital @ 7.41%	$ 3,904	$ 1,536	$ 5,440	$ 3,911	$ 1,532	$ 5,443
Income taxes	$ 400	$ 158	$ 558	$ 461	$ 181	$ 642
Service Revenue Requirement	$ 13,208	$ 5,957	$ 19,165	$ 13,313	$ 6,155	$ 19,468
Revenue Offsets	$ (1,132)	$ (271)	$ (1,403)	$ (1,132)	$ (271)	$ (1,403)
Base Revenue Requirement	$ 12,076	$ 5,686	$ 17,762	$ 12,182	$ 5,883	$ 18,065
Increase in Revenue Requirement				$ 105	$ 197	$ 303

REVENUE DEFICIENCY - MIFRS

REVENUE DEFICIENCY IN 2013	CGAAP $000			MIFRS $000		
	FE AND EOP	PC	FE, EOP AND PC	FE AND EOP	PC	FE, EOP AND PC
Rate Base	52,679	20,732	73,411	52,782	20,680	73,461
Return on Capital @ 7.41%	3,904	1,536	5,440	3,911	1,532	5,443
OM&A	5,908	2,836	8,745	6,706	3,180	9,886
Depreciation & Amortization	2,996	1,427	4,423	2,236	1,261	3,497
Income taxes	400	158	558	461	181	642
Service Revenue Requirement	13,208	5,957	19,165	13,313	6,155	19,468
Revenue Offsets	(1,132)	(271)	(1,403)	(1,132)	(271)	(1,403)
Base Revenue Requirement	12,076	5,686	17,762	12,182	5,883	18,065
Distribution Revenue	(10,830)	(5,012)	(15,842)	(10,830)	(5,012)	(15,842)
Revenue Deficiency	1,246	674	1,920	1,351	871	2,223
Increase in Revenue Deficiency				105	197	303

REVENUE DEFICIENCY TEST YEAR - MIFRS

	CGAAP			MIFRS		
REVENUE DEFICIENCY 2013 TEST YEAR	FE AND EOP	PC	FE, EOP AND PC	FE AND EOP	PC	FE, EOP AND PC
Distribution Revenue	10,830,301	5,011,916	15,842,218	10,830,301	5,011,916	15,842,218
Revenue Offset	1,131,892	271,292	1,403,185	1,131,892	271,292	1,403,185
Total Revenue	11,962,194	5,283,209	17,245,402	11,962,194	5,283,209	17,245,402
Operating Expenses	8,904,236	4,263,346	13,167,582	8,941,798	4,441,575	13,383,373
Deemed Interest Expense	1,982,043	780,009	2,762,051	1,985,901	778,048	2,763,950
Total Expenses	10,886,279	5,043,355	15,929,633	10,927,699	5,219,623	16,147,322
Income before taxes	1,075,915	239,854	1,315,769	1,034,495	63,586	1,098,080
Tax Adjustments	(817,959)	(313,033)	(1,130,992)	(650,577)	(249,508)	(900,085)
Taxable Income	257,956	(73,179)	184,777	383,918	(185,922)	197,995
Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax on Taxable Income	68,358	(19,392)	48,966	101,738	(49,269)	52,469
Net Income	1,007,557	259,246	1,266,803	932,756	112,855	1,045,612
Rate Base	52,680,275	20,731,676	73,411,951	52,782,835	20,679,574	73,462,408
Deemed Equity Portion of Rate Base	21,072,110	8,292,670	29,364,780	21,113,134	8,271,829	29,384,963
Income/Equity Portion of Rate Base	4.78%	3.13%	4.31%	4.42%	1.36%	3.56%
Target Return on Equity	9.12%	9.12%	9.12%	9.12%	9.12%	9.12%
Deficiency in Rate on Equity	-4.34%	-5.99%	-4.81%	-4.70%	-7.76%	-5.56%
Indicated Rate of Return	5.67%	5.01%	5.49%	5.53%	4.31%	5.19%
Request Rate of Return on Rate Base	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%
Deficiency in Rate of Return	-1.74%	-2.40%	-1.92%	-1.88%	-3.10%	-2.22%
Target Return on Equity	1,921,776	756,292	2,678,068	1,925,518	754,391	2,679,909
Revenue Deficiency	914,220	497,045	1,411,265	992,762	641,536	1,634,297
Gross Revenue Deficiency	1,243,837	676,252	1,920,088	1,350,696	872,838	2,223,534
Increase in Gross Revenue Deficiency				106,859	196,586	303,446

(OEB)

Accounting Standards for Private Enterprise ("ASPE")

Issue 11.3
Is the proposed change in accounting policy regarding the capitalization of overhead costs appropriate?

No Interrogatories Posed

(OEB)

Accounting Standards for Private Enterprise ("ASPE")

Issue 11.4
Is the treatment of property, plant & equipment due to the transition to a new accounting standard appropriate?

No Interrogatories Posed

Canadian Niagara Power Inc.

EB-2012-0112

Response to Green Energy Act Plan Interrogatories

(OEB)

Green Energy Act Plan

Issue 12.1
Is CNPI's proposed Green Energy Act Plan appropriate?

No Interrogatories Posed