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June 1, 2009

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
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Dear Ms. Walli:

Re: Canadian Niagara Power Inc.
Application for 2009 Electricity Distribution Rates
Board File No. EB-2008-0222, EB-2008-0223

Please find enclosed the submissions of VECC on the above noted proceedings. Again we apologize for the delay in filing and thank the Board for this indulgence.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

EB-2008-0222
EB-2008-0223

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF Applications by Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque and Canadian Niagara Power Inc. – Fort Erie pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity.

FINAL SUBMISSIONS

On Behalf of The

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

June 1, 2009

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Vulnerable Energy Consumers' Coalition ("VECC")

Final Argument

1 The Applications

Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque

1.1 Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque ("EOP") filed an application ("the Application") with the Ontario Energy Board ("the Board") dated August 15, 2008, for distribution rates and charges effective May 1, 2009. EOP claimed a Test Year distribution service revenue requirement of $2,359,739 including a deficiency at current rates of $453,093.[1]

1.2 EOP forecasted Test Year miscellaneous revenue of $135,927, reducing the forecasted increase in distribution revenues needed to eliminate the deficiency to $317,166.[2] At current rates, EOP projected Test Year distribution revenue to be $1,906,646, implying that a percentage increase in 2009 distribution revenue of 16.6% is required to eliminate the deficiency.

1.3 In its Application, EOP asked to dispose of the balance in EOP Account 1508 – Other Regulatory Assets.[3]

1.4 However, in its argument-in-chief ("AIC"), the applicant indicated that it would be "amenable" to also clearing the balances in Account 1580 – RSVA – Wholesale Market Service Charge, Account 1582 – RSVA – One-time Wholesale Market Service Charge, Account 1584 – RSVA – Retail Transmission Network Service Charge, Account 1586 – RSVA - Retail Transmission Connection Service Charge, and Account 1588 – RSVA – Power, should the Board so approve in this proceeding.[4]

[1] Ex.7/T1/S1, page 2.
[2] Ibid. Note that EOP also seeks to recover $95,837 in Low Voltage Wheeling Charges from Hydro One through a separate rate adder.
[3] Ex.5/T1/S1, page 1
[4] AIC, page 23

1.5 In its AIC, EOP requested that the Board approve the establishment of a deferral account to track IFRS costs.[5]

1.6 The Application also seeks approval of harmonized rates and charges for CNPI's EOP and Fort Erie service territories.[6]

Canadian Niagara Power Inc. – Fort Erie

1.7 Canadian Niagara Power Inc. – Fort Erie ("Fort Erie " or "FE") filed an application ("the Application") with the Ontario Energy Board ("the Board") dated August 15, 2008, for distribution rates and charges effective May 1, 2009. Fort Erie claimed a Test Year distribution service revenue requirement of $9,827,418 including a deficiency at current rates of $888,306.[7]

1.8 FE forecasted Test Year miscellaneous revenue of $574,954, reducing the forecasted increase in distribution revenues needed to eliminate the deficiency to $313,352.[8] At current rates, EOP projected Test Year distribution revenue to be $8,939,112, implying that a percentage increase in 2009 distribution revenue of 3.5% is required to eliminate the deficiency.

1.9 In its Application and AIC, CNPI's submissions for FE were identical to those for EOP, as described above in paragraphs 1.3, 1.4, and 1.5.[9]

1.10 The following sections contain VECC's final submission regarding the various aspects of EOP's Application.

2 Rate Base and Capital Spending

Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque

[5] Ibid, page 7
[6] Ex.1/T1/S2, Appendix A
[7] Ex.7/T1/S1, page 2.
[8] Ibid
[9] AIC page 23 and Ex.5/T1/S1, page 1

Rate Base

2.1 EOP's proposed 2009 rate base is $7,756,830, comprised of average net book value of fixed assets of $6,908,041 and working capital allowance ("WCA") of $848,789.[10] VECC notes that the WCA represents only 10.94% of the total EOP rate base.

Capital Spending

2.2 Excluding spending on smart meters, EOP forecasts Test Year capital expenditures of $867,901 as compared to the Bridge Year spending of $967,289.[11] Having reviewed the record, especially with respect to the system condition, "trend" in EOP distribution loss factor,[12] and reliability, VECC accepts the Test Year forecasted capital expenditures as reasonable.

Working Capital Allowance

2.3 EOP has computed the above-mentioned figure for WCA using the Board's rule-of-thumb of 15% of the sum of controllable expenses and the cost of power. Subject to EOP updating this value to incorporate the Board's most recent estimate of RPP and to reflect the most recent approved retail transmission and LV rates, VECC has no issues in respect of the WCA.

<u>Canadian Niagara Power Inc. – Fort Erie</u>

Rate Base

2.4 FE's proposed 2009 rate base is $37,463,907, comprised of average net book value of fixed assets of $33,619,024 and working capital allowance ("WCA") of $3,844,883.[13] VECC notes that the WCA represents only 10.26% of the total FE rate base.

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[10] Ex.2/T1/S1, page 1
[11] Board Staff IR #2
[12] See Section 5 below.
[13] Ex.2/T1/S1, page 1

Capital Spending

2.5 Excluding spending on smart meters, FE forecasts Test Year capital expenditures of $4,109,773 as compared to the Bridge Year spending of $4,139,102.[14] Having reviewed the record, VECC accepts the Test Year forecasted capital expenditures as reasonable.

Working Capital Allowance

2.6 FE has computed the above-mentioned figure for WCA using the Board's rule-of-thumb of 15% of the sum of controllable expenses and the cost of power. Subject to EOP updating this value to incorporate the Board's most recent estimate of RPP and to reflect the most recent approved retail transmission rates, VECC has no issues in respect of the WCA.

3 Load Forecast and Revenue Offsets

Load Forecast Methodology

3.1 CNPI utilizes the same load forecast methodology to establish the 2009 load and customer count forecast for CNPI-Fort Erie and CNPI-Eastern Ontario Power. For each customer class the energy/demand forecast is established using annual average use per customer values combined with the projected number of customers (or connections)[15]. For the weather sensitive customer classes an annual weather normalized average use per customer is established.

3.2 CNPI developed weather normalized forecasts for 2008 and 2009 for its Residential, GS<50, GS >50 and GS > 50 TOU classes[16] as follows:

- First, for each class, the actual energy used in each year from 2005 to 2007 was weather normalized based on a utility specific adjustment factor which was calculated as the product of: a) The IESO weather normalization factor for the year (expressed as a percentage) and b) The ratio of the utility's total load for

[14] Board Staff IR #2
[15] FE & EOP – Exhibit 3/Tab 2/Schedule 1, page 2
[16] Note: The GS>50 TOU class is only applicable to EOP

the year divided by its weather sensitive load. For purposes of the calculation, CNPI used the load analysis done by Hydro One Networks to identify the proportion of each customer class' load that was weather sensitive[17].

- Average annual usage values for each class were then determined by dividing these results by the number of customer in the class for year. The resulting 2007 average annual use value was used to project the use per customer in 2008 and 2008.
- The projected 2008 and 2009 customer count for each class was developed by applying the average annual growth over 2005-2007 (3 years) to the 2007 customer count. The only exception is the EOP GS>50 TOU class where the customer count is held constant at two – the 2007 value[18].

3.3 For the non-weather sensitive classes, forecast sales were developed as follows[19]:

- For each class (Street Lighting, Sentinel Lighting and USL) forecast average annual use was based on 2007 actual usage and customer count.
- For each class the 2008 and 2009 customer count forecast was based on the historical growth rate. The only exception is the Sentinel Lighting class in FE which was held constant at 2007 levels since CNPI is no longer encouraging growth in this class.

3.4 VECC has a number of issues regarding CNPI's load forecast methodology. First, the IESO weather normalization methodology captures the weather impacts across the entire province and, in doing so, reflects weather conditions and the amount of weather sensitive load across the entire province. As a result, the factor is not representative of either FE's or EOP's service area. Indeed, CNPI acknowledged this point during the oral phase of the proceeding[20].

3.5 Second, the specific adjustment factor developed for each service area (i.e., the

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[17] FE & EOP – Exhibit 3/Tab 2/Schedule 1, pages 3-5

[18] FE - Exhibit 3/Tab 2/Schedule 1, pages 8-12 and EOP – Exhibit 3/Tab 2/Schedule 1, pages 8-12

[19] FE - Exhibit 3/Tab 2/Schedule 1, pages 12-13 and EOP – Exhibit 3/Tab 2/Schedule 1, pages 13-15

[20] Volume 1, page 37 and Volume 3, pages 73-74

ratio of total load to weather sensitive load) is problematic for a couple of reasons. One, the definition of “weather sensitive” load assumes that all residential and GS<50 class loads are weather sensitive when this is readily acknowledged as not being the case[21]. Also, the factor works such that the higher the portion of weather sensitive load the lower the weather normalization adjustment, which is a counter intuitive result[22]. Finally, CNPI has acknowledged this factor does not correct for the fact the IESO adjusts for weather conditions that are different than those in CNPI’s service areas[23].

3.6 VECC notes that while acknowledging these issues CNPI’s position is that, overall, the methodology produces intuitively correct results[24]. While VECC discusses the forecast below, it submits that the methodology used by CNPI is inappropriate and that the Board should encourage CNPI to improve its load forecast methodology. To this end, VECC notes that a number of electricity distributors have developed load forecast methodologies that utilize load conditions to produce weather normalized results.

Load Forecast Results

Canadian Niagara Power Inc. – Fort Erie

3.7 In response to VECC #26 a) CNPI had provided the preliminary actual customer count for 2008 for each of FE’s major customer classes. While the numbers vary slightly from the 2008 forecast, some are higher while others are lower. Overall, VECC submits that FE’s forecast customer counts are reasonable.

3.8 The following Table sets out the historical and forecast per customer usage for the Residential, GS<50 and GS>50 classes.

[21] Volume 1, pages 33-34
[22] Volume 1, page 42
[23] Volume 1, page 37
[24] Volume 1, page 45

CNP - Fort Erie: Historical and Forecast per Customer Usage

	2002	2003	2004	2005	2006	2007	2008	2009
Residential								
- Volume (kWh)	115,599,918	110,282,589	107,800,295	114,439,113	111,959,084	114,221,401		
- Customers (#)	13,394	13,500	13,717	13,818	13,919	14,073		
- Average Use	8,631	8,169	7,859	8,282	8,044	8,116	8,056	8.056
Average						8,183		
GS<50								
- Volume (kWh)	43,031,578	42,171,824	37,800,776	40,743,120	37,929,571	37,580,115		
- Customers (#)	1,090	1,082	1,150	1,164	1,168	1,170		
- Average Use	39,479	38,976	32,870	35,003	32,474	32,120	31,881	31,881
Avearage						35,153		
GS>50								
- Volume (kWh)	124,576,619	160,794,408	137,497,781	140,488,743	133,812,631	142,072,764		
- Customers (#)	123	130	133	139	134	141		
- Average Use	1,012,818	1,236,880	1,033,818	1,010,710	998,602	1,007,608	1,004,965	1,004,965
Average						1,050,073		

Source: Exhibit3/Tab 2/Schedule 1 - Appendix A

3.9 When comparing historical usage with forecast usage one would expect the historical values to be both higher and lower due to annual weather conditions. However, VECC submits that the forecast average use values for 2008 and 2009 are too low. For the Residential class the historical results are higher than the projected average use except for two years (2004 and 2006) and in one of the two the difference is less than 0.2%. Similarly, for the GS>50 class, the historical results are less than the forecast for 5 out of the 6 years and for the one year where there is an exception the difference is only 0.6%. For the GS<50 class the projected average use is less than that in any of the previous six historical years.

3.10 In VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. At a minimum VECC recommends that the Board should direct CNPI to drop the "utility specific adjustment factor" and rely only on the IESO adjustment factor. As discussed above, the utility adjustment factor yields counter-intuitive results and does not properly adjust for service area specific conditions. VECC submits that such an approach by the Board would be consistent with its recent Decision with respect to Northern Ontario Wires where the Board directed the distributor to remove the "NOW-factor" from its weather normalization process[25].

3.11 However, in VECC's view, given the acknowledged short comings of the IESO factor a preferable approach would be to adopt the 6 year average historical per customer use value for each class as the basis for forecasting 2008 and 2009 volumes.

Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque

3.12 VECC takes no issue with CNPI's 2008 and 2009 customer count forecast for EOP.

3.13 The following Table sets out the historical and forecast per customer usage for the Residential, GS<50 and GS>50 classes.

CNP - Eastern Ontario Power: Historical and Forecast per Customer Usage

	2002	2003	2004	2005	2006	2007	2008	2009
Residential								
- Volume (kWh)	28,624,805	28,624,805	28,565,432	29,588,456	29,533,620	29,640,947		
- Customers (#)	3,042	3,042	3,072	3,097	3,099	3,100		
- Average Use	9,410	9,410	9,299	9,554	9,530	9,562	9,486	9,486
Average (2002-2007)						9,461		
Average (2003-2007)						9,471		
GS<50								
- Volume (kWh)	13,817,663	13,817,663	13,994,672	14,091,862	14,139,203	13,888,581		
- Customers (#)	378	378	398	405	412	409		
- Average Use	36,555	36,555	35,162	34,795	34,318	33,957	33,688	33,688
Avearage (2002-2007)						35,224		
Average (2003-2007)						34,958		
GS>50 (Regular)								
- Volume (kWh)	14,258,279	14,258,279	14,348,061	14,022,912	13,878,467	13,693,566		
- Customers (#)	28	28	28	29	29	31		
- Average Use	509,224	509,224	512,431	483,549	478,568	441,728	440,821	440,821
Average (2002-2007)						489,121		
Average (2003-2007)						485,100		
GS>50 (TOU)								
- Volume (kWh)	28,177,074	28,177,074	28,303,184	28,147,913	17,033,453	8,145,825		
- Customers (#)	6	6	6	6	5	4		
- Average Use	4,696,179	4,696,179	4,717,197	4,691,319	3,406,691	2,036,456	2,681,139	2,033,714
Average (2002-2007)						4,040,670		
Average (2003-2007)						3,502,277		

Source: Exhibt 3/Tab 2/Schedule 1 - Appendix
Note: The 2002 and 2003 values are exactly the same which suggests that one of the two years is incorrect. As a result both a 5 and a 6 year average have been calculated.

3.14 As noted previously, when comparing historical usage with forecast usage one

[25] EB-2008-0238, pages 6-7

would expect the historical values to be both higher and lower due to annual weather conditions. Based on the historical data, VECC submits that the forecast average use values for the Residential are reasonable. However, the GS<50 and GS>50 (Regular) values used for 2009 are too low. For the GS<50 class and the GS>50 (Regular) class, the proposed 2009 average use values are less than average use values in any of the previous 6 years[26].

3.15 Similar to FE, in VECC's view the main reason for this is the flawed weather normalization methodology used by CNPI. Again, at a minimum VECC recommends that the Board should direct CNPI to drop the "utility specific adjustment factor" and rely only on the IESO adjustment factor for the reasons outlined above. However, as outlined above, in VECC's view, a preferable approach would be to adopt the 5 year average historical per customer use value for each class as the basis for forecasting 2009 volumes[27].

3.16 In the case of the GS>50 (TOU) class, VECC accepts the 2009 projected average use as reasonable and notes that it reflects the 2008 usage of the two customers still expected to be in operation at the end of 2008[28].

4 <u>Operating Costs</u>

<u>Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque</u>

4.1 VECC notes that the proposed Test Year Operating Costs for EOP of $1,196,875 are (i) smaller than 2006 actual costs, (ii) comparable to 2007 actual costs, and (iii) are 2.57% higher than Bridge Year costs.

4.2 VECC initially had some concerns that the vegetation management costs had been inflated unduly since 2006. In Undertaking JT1.13, EOP provided an explanation for the post-2006 increases. EOP noted that pre-2007, vegetation

[26] Note: Since the 2002 and 2003 values are exactly the same there is likely a problem with the value reported for one of the two years.
[27] The use of a 5 as opposed to 6 year average is based on the cited problems with the 2002 and 2003 data.
[28] EOP, VECC #11 a)

management was undertaken by EOP line crews but the activity level was insufficient to maintain clearances. In 2007, an outside contractor was retained and in 2008, CNPI went to a 3-zone management system. EOP stated that these costs were $84,975 in 2008, forecast to be $86,343 in 2009, and expected to remain at approximately $85,000 thereafter. Subject to this understanding being correct, VECC accepts the 2009 estimate of vegetation management costs to be reasonable.

4.3 In general, while VECC's view is that operating cost increases have been contained since 2006, there remains the issue of operating cost level of EOP in comparison with its cohort. VECC notes that the Applicant maintains that the current rankings do not provide an "apples to apples" comparison. VECC has no specific recommendations on this issue other than to invite the Applicant to supply its comments and propose refinements to the benchmarking exercise so that the rankings so obtained will provide an accurate reflection of EOP's and its cohort's comparable costs.

Canadian Niagara Power Inc. – Fort Erie

4.4 The behaviour of FE's operating costs since 2006 is similar to the behaviour of EOP's operating costs since 2006 mentioned, with the exceptions that the Test Year total of $4,543,990 is significantly below 2007 actual costs (almost 7%) and is only 1.27% above Bridge Year costs.

4.5 In the case of FE, however, VECC does take issue with the component of operating costs projected for 2009 in respect of vegetation management.

4.6 VECC notes the following exchange that occurred at the oral hearing:[29]

MR. BUONAGURO: Okay, thank you. And Fort Erie, I think you mentioned here, is also on a three-year program just like Port Colborne?

MR. SHEOGOBIND: Yes, all the CNPI territories are on a three-year program.

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[29] Transcript, Volume 1, pages 126-128

MR. BUONAGURO: Now at Exhibit 4, tab 2, schedule 3, appendix A, page 3, you talk about the actual cost, and you indicate here that the vegetation program costs for Fort Erie are forecast to increase by $68,608 over 2008 levels; do you see that?

MR. SHEOGOBIND: Yes, that's correct.

MR. VLAHOS: Just for the record it is $68,608.

MR. BUONAGURO: Yes, thank you. Do you have an actual figure for the 2008 costs?

MR. SHEOGOBIND: Not off the top of my head, but it was pretty close to forecast.

MR. BUONAGURO: And based on your earlier -- our earlier conversation about how you tender it, that's a 100 percent third-party contract cost?

MR. SHEOGOBIND: It's 100 percent, yes, with some slight exceptions where outage situations if our crews on the scene and a tree branch problem, they might do some pruning, but for the most part it is a third-party contract labour.

MR. BUONAGURO: We a long conversation of why the spike in 2009 -–

MR. SHEOGOBIND: Right.

MR. BUONAGURO: -- for Port Colborne, is that the same answer for the Fort Erie or is there something different?

MR. SHEOGOBIND: Not exactly. It's something different in Fort Erie. In Fort Erie, we have a couple of utility rights of way and we maintain the rights of way in terms of vegetation management on a cyclical basis. So the cost you are seeing here, the 68,000 and change, it's -- we see that cost in 2009, but then we won't see it for another three years or so.

MR. BUONAGURO: Okay.

MR. SHEOGOBIND: So what we do is every so often, we'll have an intensification to address issues on the right of ways.

MR. BUONAGURO: I see, that's useful then. So the 68,000 or so increase for 2009 is a 2009 cost which you don't anticipate to occur in 2010, 2011 or 2012?

MR. SHEOGOBIND: Yes, that would be correct. And I guess I should elaborate, too, on the rights of way. These are off-road rights of way. In some cases like old subtransmission rights of way and railroad rights of way, so because of the fact that they are off-road, they do need special attention from time to time.

MR. BUONAGURO: Okay. Now many the context of -– well, maybe I am being presumptuous. My assumption has been the companies would be applying for an IRM adjustment next year and the years follow.

MR. BRADBURY: That's correct.

MR. BUONAGURO: So in the case like this where you have a $68,000 2009 circulated cost, would it be more appropriate to divide it, I think it would be by four so that you would recover part of it in 2009, 2010, 2011 and 2012 over the course of the IRM.

MR. BRADBURY: It is a 2009 cost nevertheless, it's the nature of our system. Fort Erie is fairly vast geographically, and as we mentioned there are a number of off-road right of ways and they require attention. It is expensive and there is a fair amount of set-up time because the normal contractor who drives along the road in a bucket truck and does our tree-trimming needs more specialized equipment to go off-road and travel the right of ways to do it. So it's not something you want to do every year, but you need the address it on a cyclic basis so it happens to occur this year.

4.7 VECC submits that the 2009 vegetation management cost increase of $68,608 represents a one-time cost and should be levelized over the IRM period rather than embedded in base rates. As such, VECC submits that the FE Operating Costs should be reduced by $51,456 to $17,152 for the purposes of Test Year rates.[30]

5 Losses

Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque

5.1 Using three-year averages of actual values for 2005-2007, EOP proposes a TLF for secondary metered customers < 5,000 kW of 1.0719 for the Test Year. The TLF embodies a three-year average SLF of 1.0272 and a three-year average DLF of 1.0438.[31] The relatively high TLF is a cause for concern to VECC.

5.2 In its Application, EOP states,

> "CNPI – Eastern Ontario Power has seen the distribution loss factor increase to 8.7% in 2007 from 3.63% in the Board approved 2006 EDR. This increase is attributable to the following two primary factors:
>
> - The relationship of embedded generation capacity and distribution system load requirements; and
> - The loss of significant industrial loads connected at 26 kV and 44 kV."[32]

5.3 VECC notes that the high 2007 losses due to the first factor, relating to the fact that reverse power flows related to embedded generation had not been previously metered, should not be expected to recur because reverse flow power metering instrumentation at the delivery point from Hydro One's network has since been installed.[33]

5.4 While the relative impacts of these two factors are unknown, VECC expects that

[30] The amount $17,152 is just the total one-time increase of $68,608 divided by 4.
[31] Ex.4/T2/S8, page 1
[32] Ibid, page 2

for 2008 and beyond, losses will be lower than expressed by the proposed DLF embedded in the TLF since the reverse power flow problem has been remediated.

5.5 VECC therefore proposes that the EOP TLF be calculated using the average of the Board approved 2006 EDR DLF factor of 3.63% and the actual average 20005-07 DLF of 4.38% resulting in a DLF for the Test Year of 4.01% and a TLF therefore of 6.83% or 1.0683.[34]

Canadian Niagara Power Inc. – Fort Erie

5.6 Using three-year averages of actual values for 2005-2007, FE proposes a TLF for secondary metered customers < 5,000 kW of 1.0391 for the Test Year. The TLF embodies a three-year average SLF of 1.0033 and a three-year average DLF of 1.0357.[35]

5.7 VECC notes that losses have decreased in the FE service area since 2006 and that FE suggests that the continued conversion from 3-wire delta to 4-wire wye configuration along with service at a higher voltage level intuitively should lead to the lower losses on record and into the future.

5.6 VECC submits that the proposed TLF for the Test Year is acceptable.

6 Cost of Capital/Capital Structure

Canadian Niagara Power Inc. – Eastern Ontario Power/Gananoque and
Canadian Niagara Power Inc. – Fort Erie

6.1 For the Test Year, CNPI seeks a deemed capital structure of 52.7% long-term debt, 4% short-term debt, and 43.3% equity for EOP and FE. The Applicant has advised that the short-term debt and the return on equity will be updated using

[33] The second factor, at least in the short run, appears to be beyond the utility’s control.
[34] This is calculated using the SLF of 1.0272 provided by the utility along with VECC’s proposed DLF.
[35] Ex.4/T2/S8, page 1

data from *Consensus Forecasts* and the Bank of Canada/Statistics Canada, per the Board Report.[36] VECC takes no issue with the proposals in respect of short-term debt and return on equity for the Test Year.

6.2 With respect to long-term debt, CNPI has embedded third-party debt and affiliate debt.[37]

6.3 Regarding the third-party debt, CNPI has $30M in senior unsecured notes issued on August 14, 2003 and repayable upon maturity on August 14, 2018. The interest rate on this embedded debt is 7.092% and CNPI has used this rate, plus term-amortized issue costs and standby fees, for this component of long-term Test Year debt costs.[38]

6.4 In its pre-filed evidence, CNPI stated that it had issued a $15M demand promissory note to FortisOntario in August 2008 *"which bears interest at 6.13%. The Board Report states "for new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate." CNPI has used a deemed long-term debt rate of 6.13% in the 2009 Test Year based on the approach in Appendix A of the Board Report, using the May 2008 DEX long-term bond index (all corporate)."*[39] A copy of the promissory note was provided in response to SEC IR #18. This component of long-term debt is not embedded in current rates.

6.5 Under cross-examination, CNPI admitted that while FortisOntario could call the loan at its pleasure, CNPI would not be able to pay off the FortisOntario debt to take advantage of lower market rates without the permission of the debt holder.

> *MR. BUONAGURO: Thank you. And my next question -- I can't remember if I asked or not, but my next question was whether CNPI has the option of repaying the note upon notice to Fortis Ontario.*

[36] Ex.6/T1/S1 in the EOP and FE pre-filed evidence.
[37] Ibid
[38] Ibid
[39] Ex.6/T1/S1, page 3 in the EOP and FE pre-filed evidence.

MR. KING: The promissory note is silent on that issue, so CNPI has no rights to repay. …

MR. BUONAGURO: So the position would be that you would have to negotiate that with Fortis?

MR. KING: We have no right to repay.

MR. BUONAGURO: I don't have a deep background in the law of promissory notes. Is that a legal position from CNPI as to whether you have the right or not in the absence of a specific right?

MR. TAYLOR: I think that the straightforward evaluation of this situation is that this is a demand note. It's callable on demand by the issuer of the debt, as contemplated by the Board's cost-of-capital report.

MR. BUONAGURO: Okay. Now, if it were -- if it were the case that I was able to successfully make an argument in law that you had the option of paying it upon notice in advance of the dates in the document, would CNPI consider refinancing if low rates were available by paying off the note and obtaining lower interest rates from somewhere else?

MR. KING: Well, the obvious answer, yes, if lower rates were available, correct.

MR. BUONAGURO: Right. But of course your position is that you can't refinance without Fortis Ontario's permission, I guess you would call it.

MR. KING: Correct.[40]

6.6 Notwithstanding the Application and pre-filed evidence, CNPI indicated, under cross-examination by counsel for Board staff, that (i) it intended to recover a debt rate of 7.62% from ratepayers on the affiliated debt and that (ii) FortisOntario would possibly call the $15M note in 2009 and replace it with a note for $21M (to provide an additional $6M) which would attract the Board’s deemed long-term rate of 7.62%.

[40] Transcript, Volume 1, pp 84-85

MS. COCHRANE: Well, we would just like to get some of that a little bit clearer on the record. I think there was some confusion yesterday as to what exactly the Board reports said and whatnot. So I unfortunately do not have a copy of the Board report to refer you to, but I am just going to read an excerpt. It's page 13 under Section 2.21, and that's the report of the Board on the cost of capital and second-generation incentive regulation for Ontario's electricity distributors dated December 20, 2006. That was the report on the record. And on page 13, the report says:

> *"For new affiliated debt, the Board has determined that the allowed rate will be the lower of the contracted rate and the deemed long-term debt rate".*

Now, just to clarify, the contracted rate of this promissory note is 6.13 percent. And again, just to clarify, the Board's current deemed long-term debt rate would have been set out in a letter to electricity distributors February 24, 2009, which we will make an exhibit, it will be Exhibit K2.1. Over on page 2, the long-term debt rate is set out the deemed long-term debt rate set out as 7.62 percent. Now, is that the rate that CNPI is claiming should be allowed on this promissory note?

MR. TAYLOR: CNPI is claiming that the deemed debt rate would apply, the long-term deemed debt rate.

MS. COCHRANE: Okay. And, again, I am referring to the Board report which states on the top of page 14:

> *"For all variable rate debt and for all affiliate debt that is callable on demand, the Board will use the current deemed long-term debt rate."*

Is that the basis for CNPI's position that this is affiliate debt that is callable on demand and therefore the deemed long-term debt rate should apply?

MR. TAYLOR: Do you want to answer that?

MR. KING: Correct.

MR. TAYLOR: Yes.

MR. KING: Can I add one thing to that. The promissory note that is in evidence is for $15 million. If you also look at our pro forma financial statements also included in evidence, we expect to have $21 million in affiliated debt by the end of '09. So there would be for a second -- possibly a recall for the first, and a second promissory note issued.

MS. COCHRANE: When do you anticipate that happening?

MR. KING: '09.[41]

6.7 VECC notes that in this case, the shareholder and the debt holder are the same entity, FortisOntario. While it would typically be the case for a utility to try to find the lowest market debt rate available <u>from a third party</u> to finance its capital structure, here the shareholder has a financial incentive to obtain the highest debt rate and return on equity that it can.

6.8 VECC adds that callable or demand loans would usually be expected to have an interest rate that is lower than the rate on non-callable loans as demand loans are less attractive to the entity seeking debt financing, other things being equal.

6.9 Further, in the case of a utility obtaining debt capital from its shareholder, VECC submits that counterparty risk is lower for the provider of the debt capital than it would be in the case of third-party debt obtained at market rates.

[41] Transcript, Volume 2, pp 16-18

6.10 Finally, the fact that the debt holder can call the loan at any time and for any reason (while the same privilege is not extended to the utility), could require the utility to incur avoidable costs of seeking new debt financing in a perhaps illiquid market on short

6.11 VECC submits that the Board's report did not seem to contemplate the asymmetrical conditions that exist for CNPI with respect to affiliate long-term debt.

7 Deferral and Variance Accounts

7.1 As noted above, the Applicant originally proposed that the balance in Account No. 1508 be disposed of in this proceeding for the EOP and the FE service areas. However, in its AIC, the Applicant indicated its willingness to dispose of the balances in RSVA Account Nos. 1580, 1582, 1584, 1586, and 1588, should the Board so order in this proceeding.

7.2 VECC notes that the disposition of the RSVA accounts is the subject of a separate Board initiative which is currently underway.

7.3 VECC further notes that the rate rider calculations provided in Undertaking JT2.2 to clear the named accounts appear to be incorrect in the case of FE[42] and, in any case, have not been tested for accuracy or bill impact.

7.4 Given the preceding, VECC submits that it would be premature to approve the disposal of all of the named accounts absent further testing. VECC submits that the Board should consider only approving the initial request after satisfying itself that the proposed riders are just and reasonable.

8 Cost Allocation

Results of CNPI's Cost Allocation Informational Filing and Customer Classification

[42] The rate rider calculations for customer classes appear to be wrong, as noted by Board staff in its submissions.

8.1 CNPI's Cost Allocation Informational Filings produced[43] the following revenue to cost ratios:

CNP's Cost Allocation Informational Filing

	CNP-FE	**CNP-EOP**	**Harmonized**
Residential	82.69%	73.02%	80.52%
GS<50	129.81%	142.48%	133.51%
GS>50 (Regular)	151.44%	158.23%	154.80%
USL	56.76%	65.40%	57.76%
Sentinel Lighting	37.35%	31.77%	37.46%
Street Lighting	19.16%	27.64%	19.51%

Sources: CNP-FE - Exhibit 8/Tab 1/Schedule 2, page 1
CNP-EOP - Exhibit 8/Tab 1/Schedule 2, page 1
CNP-EOP - Exhibit 10/Tab 1/Schedule 2, page 2

8.2 Currently there are two GS>50 customer classes in the EOP service area: a) GS>50 (Regular) and b) GS>50 (TOU). For 2009, CNPI is proposing to combine these two class into one (GS>50). This proposal is in response to the Board's EB-2007-0594 Decision which directed CNPI to eliminate the GS>50 (TOU) class as part of its next rate application[44]. As a result, the Cost Allocation run used for EOP (and for the Harmonized results) combined the current GS>50 (Regular) and GS>50 (TOU) classes into one GS>50 class.

Use of the Cost Allocation Informational Filing Results in Setting 2009 Rates

8.3 CNPI has filed proposals regarding the 2009 revenue to cost ratios by customer class assuming rate harmonization of the FE and EOP service areas and a separate proposal should the Board determine that rate harmonization not be pursued. In each case, CNPI has used the shares (percentages) of revenue requirement from its Cost Allocation run (adjusted for miscellaneous revenues) to determine what portion of the 2009 base distribution revenue requirement would

[43] Exhibit 8/Tab 1/Schedule 1, page 6
[44] CNPI Argument in Chief, page 27

represent 100% cost responsibility for each customer class[45].

8.4 The only exception is for the EOP cost allocation where the informational filing yielded anomalous results for the allocation of miscellaneous revenues and revised allocation was developed in order to determine the distribution revenues required by customer class consistent with 100% cost responsibility[46]. VECC agrees that some adjustment was required as, intuitively, the allocation of miscellaneous revenues should not yield the negative results that were produced[47].

8.5 However, VECC has four concerns regarding the overall approach used by CNPI in using its 2006 Cost Allocation Informational filing results to develop 2009 rates. First, VECC notes that in all three cases, the reported proposed revenue to cost ratios are calculated based on each class' proposed distribution revenues relative to its allocation of the base distribution revenue requirement – where both the numerator and the denominator exclude miscellaneous revenues[48]. In contrast, the revenue to cost ratios calculated in the Cost Allocation Informational filing are based on total Service Revenue Requirement (including miscellaneous revenues)[49]. CNPI has acknowledged that the different treatment of miscellaneous revenues will yield different revenue to cost ratio results[50]. VECC recognizes that the differences may not be that great and the implications immaterial provided the Board is not trying to target revenue to cost ratios that are virtually 100%.

8.6 Second, in the case of the EOP and the Harmonized cost allocations CNPI has included the charges from HON for LV (now ST) service in the base distribution revenue requirement to be allocated. VECC notes that this is contrary to the revenue requirement definition used in the Cost Allocation Informational filing[51].

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45 FE, VECC #25 a)
46 EOP Exhibit 8/Tab 1/Schedule 1, pages 2-4 and VECC #4 b)
47 EOP, VECC #4 a)
48 Volume #1, pages 94-95
49 Volume #1, page 94
50 Volume #1, page 95
51 EOP, VECC #8 a)

While the costs are subsequently backed out, this adjustment does not remove the costs on the same basis they were allocated[52]. Again, VECC acknowledges the differences may not be great but notes that CNPI has agreed that the correct calculation could be included in its rate derivation[53].

8.7 VECC's third concern is with CNPI's use of the class revenue requirement distribution from the Cost Allocation Informational filing to determine 100% cost responsibility for 2009[54]. This approach only works if the billing parameters (i.e., kWhs, kWs and customer count) represent close to the same proportions by class in 2009 as they did in the Cost Allocation filing. The reason for this is that costs are allocated to classes based on allocation factors that reflect the relative loads and customer count by class. If these relative values change then so will the relative cost responsibility by customer class. Indeed, a number of the utilities filing 2009 Rate Application have recognized this issue and have assessed the ongoing validity of their Cost Allocation Informational filing as part of their 2009 Rate Application[55].

8.8 One way to get an indication as to the potential for cost shifts is to compare the responsibility for distribution revenue from the Cost Allocation filing with that which arises from using 2009 billing parameters and 2008 rates. The following table provides such a comparison.

Distribution Revenue Responsibility

	CNP-FE		CNP-EOP		Harmonized	
	2008 Rates	2006 CA Study	2008 Rates	2006 CA Study	2008 Rates	2006 CA Study
Residential	50.40%	50.80%	44.60%	44.28%	49.41%	49.65%
GS<50	12.93%	14.82%	20.83%	20.84%	14.28%	15.88%
GS>50	35.32%	33.12%	33.24%	33.94%	34.96%	33.26%
USL	0.24%	0.22%	0.26%	0.12%	0.24%	0.21%
Sentinel L	0.34%	0.31%	0.14%	0.09%	0.30%	0.27%
Street L	0.77%	0.72%	0.93%	0.74%	0.80%	0.73%

Sources: 2008 Rates - Ogilvy Renault January 16,2009 Letter, pages 9-10 - with GS>50 revenues adjusted for transformer discount
2006 CA Study - CNP-FE VECC #20 d) & #23 c) and CNP-EOP VECC #6 d) - with GS>50 revenue adjusted for TOA

[52] EOP, VECC #8 a) & b)
[53] EOP, VECC #8 b)
[54] Final Argument, Appendix C.6
[55] Examples include COLLUS Power (EB-2008-0226) and Bluewater Power (EB-2008-0221)

8.9 The revenue responsibility proportions are fairly similar for most classes, particularly in the Harmonization case. In VECC's view where there are differences that could prove material, a preferred approach is to assume that revenues at current rates are consistent with the revenue to cost ratios determined via the cost allocation informational filing and use this as the starting point to determine the allocation of the distribution revenue requirement that would yield 100% cost responsibility for each class. Since no efforts were made to realign the revenue to cost ratios in 2007 or 2008, there is no reason to assume that the current revenue to cost ratio for each class would be any different than those arising from the cost allocation informational filing.

8.10 However, VECC submits that in CNPI's case there is likely no need to make such adjustments provided the Board does <u>not</u> intend to implement revenue to cost ratios that are targeted to be closer to 100% than the Board's recommended ranges.

8.11 Fourth, CNPI is proposing to allocate the "cost" of the transformer ownership allowance solely to the GS >50[56]. VECC agrees with this change and notes that it is consistent with the approach approved for a number of distributors' 2008 and 2009 rates. The treatment of transformer ownership allowance in the current OEB Cost Allocation model results in an over allocation of costs to those classes where customers generally <u>do not own</u> their own transformers (e.g. Residential and GS<50). This circumstance arises because the model not only allocates these classes the full cost of the transformers used to serve them but also a share of the "cost" of the discount.

8.12 In principle the discount is an <u>intra-class</u> issue for those classes where some customers own their transformer and other don't. The Cost Allocation model recognizes that some customers own their transformers. However, unless a discount is introduced for these customers (and paid for by the other customers in the <u>same</u> class) those customers in the class who own their transformer will pay

[56] FE, VECC #20 c) and EOP, VECC #6 c)

too much and those who don't will not bear full cost responsibility for the transformers they use.

8.13 To accommodate this change and be consistent with its own proposals, CNPI's Cost Allocation results used should exclude the cost of the transformer ownership allowance from the allocation of the revenue requirement to customer classes and, instead allocate it directly to the GS>50 classes after the cost allocation adjustments have been completed. CNPI provided revised versions of its Cost Allocation Informational filings that attempted to follow this approach[57]. However, in each case, the Applicant neglected to remove the lost revenues associated with the transformer ownership discount from the GS>50 distribution revenues. This is readily evidenced by the fact that, in each case, total Revenues do not equal the total Revenue Requirement and the difference is precisely equal to the value of the 2006 transformer allowance[58]. The following Table summarizes the revenue to cost ratios by class if this correction is made.

CNP's Cost Allocation Informational Filing Adjusted for Transformer Allowance

	CNP-FE	CNP-EOP	Harmonized
Residential	83.60%	74.67%	81.58%
GS<50	131.28%	144.97%	135.20%
GS>50	148.21%	152.30%	150.90%
USL	56.52%	65.43%	57.47%
Sentinel Lights	38.07%	33.19%	38.38%
Street Lights	19.53%	20.03%	20.00%

Sources: CNP-FE VECC #20 d) with GS>50 revenues reduced by $106,151 for transformer discount
CNP-EOP VECC #6 d) with GS>50 revenues reduced by $47,378 for transformer discount
Harmonized - per CNP-FE VECC #23 with GS>59 revenues reduced by $153,530

It is VECC's submission that these are the revenue to cost ratios[59] that should be considered consistent with current rates and used as the starting point for considering any reallocation of costs between customer classes.

Proposed Revenue to Cost Ratios

[57] EOP VECC #6 d) and FE VECC #20 d) and #23 c)
[58] The 2006 transformer ownership allowance values can be found on input sheet I3 of the relevant Cost Allocation filing run.
[59] In the preceding Table VECC has not incorporated the revised allocation of Miscellaneous Revenues which would change the ratio for EOP slightly.

8.14 CNPI's general approach in developing its proposed revenue to cost ratios for 2009 was to attempt to move the ratios for those classes who were outside the Board's recommended ranges closer to the range/within the range while respecting the Board's bill impact criteria[60].

Harmonized Rates for EOP and FE

8.15 The following Table compares the CNPI's proposal for 2009 rate harmonization with the revenue to cost ratios CNPI has indicated result from its Cost Allocation run and those determined using the Cost Allocation run adjusted for the Transformer Ownership Allowance.

CNP's Proposed R/C Ratio Shifts - Rate Harmonization

	CNP CA R/C Ratio	**VECC CNP-FE #23**	**Proposed R/C Ratio**
Residential	80.52%	81.58%	82.88%
GS<50	133.51%	135.20%	120.00%
GS>50	154.80%	150.90%	152.66%
USL	57.76%	57.47%	44.69%
Sentinel Lights	37.46%	38.38%	54.61%
Street Lights	19.52%	20.00%	23.91%

1) CA Ratio per CNP-EOP Exhibit 10/Tab 1/Schedule 2, page 2
2) The GS>50 value for VECC #23 has been adjusted to remove the Transformer Allowance revenue
3) Proposed R/C ratio per CNP-EOP Exhibit 10/Tab 1/Schedule 2, page 3

8.16 CNPI has indicated that in the case of the Residential, USL, Street Lights and Sentinel Lights classes the movement in the revenue to cost ratios was limited by the objective of restricting the total bill impacts for the customers in these classes to no more than 10%[61]. VECC notes that the resulting bill impacts for the some Residential customers actually exceed 10% based on the updated Rate Design Model filed with the interrogatory responses. Indeed, across a full range of possible consumption levels the impacts range from 10.2% to 10.8% for the Residential customers in the EOP service area[62]. VECC submits that the

[60] Volume #2, page 19 and SEC #22
[61] EOP Exhibit 10/Tab 1/Schedule 2, page 3
[62] Updated Harmonized Rate Design Model, Tab – EOP Customer Bill Impacts

approach adopted by CNPI is reasonable as it permits some movement on the Residential revenue to cost ratio.

8.17 VECC's only caveat is that while the additional revenue from increases in the revenue cost ratios for those classes that are below the Board's range should be directed to the GS<50 class[63], CNPI should ensure that the ratio for the GS>50 class does not increase as it would appear to do under CNPI's current proposal.

8.18 Overall, VECC supports CNPI's proposal to harmonize the distribution rates for FE and EOP. VECC notes that despite the geographic separation CNPI has indicated that there are considerable shared costs between the two service areas and harmonization would introduce efficiencies[64]. VECC also notes that in areas where there are differences, such as loss factors, RTSR charges, debt retirement charges and LV charges, CNPI is proposing to maintain rate differentials[65].

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8.19 CNPI has also filed a cost allocation proposal for FE, in the event that the Board does not accept its proposal for rate harmonization of the two service areas. The proposal is based on generally the same principles as outlined above[66] and bill impacts are the constraining factor in not increasing the revenue to cost ratios for USL, Street Lights and Sentinel Lights all the way to the lower end of the Board's recommended range for each class[67].

8.20 VECC's only observation is that since the GS>50 class is already well within the Board's recommended range and the GS<50 ratio is adjusted so as to conform with the Board's recommended range, there is no need to increase the Residential ratio beyond 85%.

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[63] As it is the only class whose ratio is currently above the Board's range.
[64] Volume #2, pages 30-32
[65] Volume #2, pages 31-34 and SEC #20 & #21
[66] FE – Exhibit 8/Tab 1/Schedule 2, page 2
[67] FE – Exhibit 9/Tab 1/Schedule 1, page 11

8.21 Similarly, CNPI filed a cost allocation proposal for EOP[68], in the event that the Board does not accept its proposal for rate harmonization. Again, bill impacts were constraining factor in increasing the ratios for the Residential, Street Lights and Sentinel Lights classes[69].

8.22 VECC only concern is CNPI's proposal to increase the revenue to cost ratio for USL to 99.81%. The Board, through the *"Application of Cost Allocation for Electricity Distributors: Report of the Board"*, has reviewed the Cost Allocation Model and the data used in running it and determined that, as evidence of cost causality, it is inappropriate to rely on runs of the model to move to a revenue to cost ratio of unity. Rather, the Board has adopted a range approach as opposed to the implementation of a specific revenue to cost ratio.[70] The Report cited several reasons for reaching the conclusion that the Cost Allocation Study could not be strictly applied, including:

- the quality of the data (both accounting and load data),
- limited modeling experience, and
- the status of the current rate classes.

8.23 In the case of EOP there are additional issues with the cost allocation methodology and how the results are applied by CNPI including the allocation results for miscellaneous revenues and the treatment of LV costs. As a result, VECC submits that there is all the more reason to work with the ranges adopted by the OEB when establishing the rates for CNPI's service areas and its is inappropriate to adjust the ratios to virtually 100%.

9 <u>Rate Design</u>

9.1 As noted earlier, VECC supports CNPI's proposal to harmonize the distribution rates for the FE and EOP.

Harmonized Rates

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[68] EOP – Exhibit 8/Tab/Schedule 2, page 2
[69] EOP – Exhibit 9/Tab 1/Schedule 1, page 14
[70] Page 4

9.2 In the case of the Residential class CNPI is proposing to recover 63% of the base distribution revenue requirement through the fixed charge[71]. For both FE and EOP residential customers, this represents an increase in the portion of the revenue requirement recovered through the variable rate. CNPI's rationale for doing so was to limit the bill impact from the proposed revenue to cost ratio increase[72]. As demonstrated in the evidence the resulting total bill impacts for EOP's residential customers are between 10.2% – 10.8% across a full range of possible consumption levels[73]. Furthermore, for the more than 30% of EOP's Residential customers[74] (i.e., those using less than 500 kWh per month) the impacts are 10.6% or greater. VECC supports CNPI's proposed shift in the Residential fixed-variable split and notes that the resulting service charge is below but approaching the upper limit of the Board's prescribed range[75].

LV Costs

9.3 The harmonized rates for the EOP service area include an LV rate adder. The proposed adder is based on 2009 forecast LV costs of $95,837[76]. However, this value was developed prior to the Board's Decision regarding Hydro One Networks' 2009 Distribution Rates[77]. VECC invites CNPI to address the impact of HON's 2009 rates on the forecast LV costs as part of its final argument.

9.4 VECC also notes that the allocation of the LV costs to customer classes is based on allocation factors derived from the 2006 EDR. VECC submits that the allocation factors should be updated to reflect the 2009 forecast RTSR-Connection revenues by customer class.

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[71] Updated Harmonized Rate Design Model, Tab – Cost Allocation Revenue Distribution
[72] EOP / Exhibit 10/Tab 1/Schedule 3, pages 14-15
[73] Updated Harmonized Rate Design Model, Tab – EOP Customer Bill Impacts
[74] EOP VECC #9
[75] Updated Harmonized Rate Design Model, Tab – Monthly Service Charge Analysis
[76] Updated Harmonized Rate Design Model, Tab – Low Voltage
[77] EB-2008-0187 – A revised draft rate order was filed with the Board on May 29th, 2009.

10 Retail Transmission Service Rates (RTSR)

10.1 In its August 2008 Application CNPI did not propose to make any changes to its approved RTSR other than to combine the current rates for the GS>50 (Regular) and the GS>50 (TOU) classes into one "average" rate consistent with its proposal to amalgamate the two classes into one. In response to Board Staff interrogatories CNPI filed a proposal for new 2009 RTSR that reflected changes In the provincial uniform transmission rates and the trends in the related variance accounts' balances.

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10.2 In the case of FE, an analysis of 2006 and 2007 balances indicates that costs have exceeded revenues by 3% in the case of Network Service and 5% in the case of Connection Service[78]. As result, CNPI is proposing to adjust the RTSR for FE by 14.26% in the case of Network Service (11.26% for the uniform increase and 3% for the trend) and 10.45% in the case of Connection Service (5.45% for the uniform increase and 5% for the trend).

10.3 VECC's only concern with CNPI's proposal is that the trend analysis under taken for the variance accounts does not appear to make any allowance for the fact that RTSR adjustments have not coincided (time-wise) with the adjustments in the uniform transmission rates. This will lead to inherent monthly variances that, in principle, should be excluded from any trend analysis. VECC notes that the "trend adjustments" are not overly significant, but invites CNPI to address this concern in its Reply Argument.

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10.4 EOP is an embedded distributor (within HON). A similar analysis of its 2006 and 2007 RTSR-related variance accounts indicated that revenues exceeded costs by 15% for both Network and Connection Service. At the time CNPI made its

[78] OEB Staff #68

application, Hydro One Networks had not indicated what, if any, changes it was proposing to its 2009 RTSR for sub-transmission (LV) customers. However, based on the Board's EB-2008-0187 Decision regarding Hydro One Networks' 2009 Distribution rates and Hydro One Networks' draft rate order their retail charges for Network and Connection Service are expected to increase by 11.44% and 5.85% respectively.

10.5 VECC submits that the proposed RTSR for EOP should be revised to also reflect the expected changes in Hydro One Networks' 2009 RTSR. VECC notes that the analysis for EOP RTSR variance accounts was done on the same basis as that for FE. As result, VECC invites CNPI to comment on the impact historical timing differences will have had on the observed monthly variances.

11 Smart Meters

11.1 CNPI currently collects a smart meter rate adder of $0.26 per metered customer per month in EOP and $0.27 per metered customer per month in FE. Under the harmonization proposal, CNPI proposes to charge a smart meter rate adder of $0.27 per metered customer per month in both service areas.

12.2 VECC has no issues with this proposal.

12 Recovery of Reasonably Incurred Costs

12.1 VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.

Respectfully Submitted on the 1st Day of June 2009

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