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December 9, 2013

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC)
Final Submissions:EB-2013-0139
Hydro Hawkesbury Inc. – 2014 Electricity Distribution Rate Application

Please find enclosed the submissions of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

cc: Hydro Hawkesbury Inc. - Michel Poulin - michelpoulin@hydrohawkesbury.ca

EB-2013-0139

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 an Application by Hydro Hawkesbury Inc. pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for electricity distribution to be effective January 1, 2014.

FINAL SUBMISSIONS

ON BEHALF OF THE

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

December 9, 2013

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Vulnerable Energy Consumers Coalition (VECC)
Final Argument Hawkesbury Hydro Inc. EB-2013-0139

1 THE APPLICATON

1.1 In making these submissions we have relied on the final filings made by Hawkesbury Hydro Inc. (HHI) on November 6 and 12. VECC has also reviewed the submissions of Board Staff made on December 2, 2013. Staff's submissions are comprehensive and we have tried to avoid repeating the evidence and arguments where we are in substantive agreement with Staff.

2 RATE BASE

2.1 We believe Board Staff has summarized the relevant evidence in respect to capital expenditures accurately. VECC concurs with the submission made by Staff that the existing rate base growth and the proposed capital programs of the Utility follow a sustained trend which is largely in line with past spending.

Service Reliability

2.2 In addition to reviewing the standard service reliability statistics, VECC asked HHI to provide indices of the reasons for these outages. We have reproduced the indices related to scheduled outages and defective equipment which are two areas indicative of the health of the distribution system. We note the declining value of outage time in these two areas suggests HHI maintains its distribution system in a prudent and sustainable fashion.

Unitized Statistics and Service Quality Requirements	2010	2011	2012
Service Reliability Indices			
SAIDI-Annual	1.17	1.07	0.78
SAIFI-Annual	1.04	1.46	0.89
CAIDI-Annual	1.12	0.73	0.87
Loss of Supply Adjusted Service Reliability Indices			
SAIDI-Annual	1.17	0.19	0.76
SAIFI-Annual	0.90	0.19	0.69
CAIDI-Annual	1.30	0.98	1.09
Total Customer Hours Scheduled Outage*	4777	392	609
Total Customer Hours Defective Equipment Outage*	1425	138	40

Source: E2/Tab3/E2.T3.S1/ 2-Staff-11 & 1-Vecc-1 *(rounded)

Capital Expenditures

2.3 The capital expenditures forecast of HHI is in two parts. The normal 2013 and 2014 expenditures and those related to the previously approved ICM application.

2.4 Staff suggests that the capital expenditures outside of the ICM projects are relatively stable. While VECC does not dispute the assertion that the non-ICM budget is reasonable we would note that the average non-ICM spending between 2010 and 2012 was $210,000 as compared to an average of $278,000 between 2013 and 2014. As a result of introducing a distribution asset management plan HHI, like many other utilities implementing new plans, has embarked on a bigger capital program than past experience would suggest. In particular, HHI has increased spending on poles. In 2010 and 2011 pole replacement averaged $28,000, whereas the 2012-2014 annual average spending is approximately $90,000.[1] We have noticed a similar trend by a number of utilities that have introduced new asset management plans as part of their cost of service filings[2]. While we are not making any specific submission in this matter we do note that HHI is following a trend among Ontario electric distribution utilities to depart from

[1] 2-Staff-3
[2] 2-VECC-7

past practice in the area of pole replacement.

ICM Reconciliation

2.5 Board Staff has made detailed submissions in respect to the reconciliation of the ICM capital budget and the in-service amounts (ISA). We agree with Staff that the Board has clearly articulated its policy for ICM in respect to this issue. This policy is clearly articulated in the Board's Partial Decision and Order in EB-2012-0064 the ICM proceeding in respect to the Toronto Hydro-Electric System Limited.[3]

2.6 In its Decision EB-2011-0173 the Board approved for HHI an ICM amount of $2,230,722[4]. This was comprised of two amounts $1,517,813 for the new 25MVA transformer (110V substation) and $712,909.[5]

2.7 In the event the actual spending for the 44kV station was $790,136. The reason for the difference in costs was unexpected remedial soil and foundation work. In respect to the substation only $376,006 has been spent, all of which is related to engineering work and the payment of circuit switches. At the time of responding to the interrogatories (November 2013) HHI was only in the process of preparing grounds for the site[6]. HHI has suggested the in-service date for the 110kV transformer is April 2014. The current state of construction suggests it may even be later than that. In any event, it will not be as originally projected - in service in 2013.

2.8 Board Staff asked that HHI calculate the ICM incremental revenue requirement based on the actual spending. HHI did not do this, explaining the work was onerous and suggesting that the resulting rate rider did not cover the cost of the project including unanticipated costs of $200,000. No detail was given as to the nature of these costs. As of October 31, 2013 HHI had collected $311,000

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[3] Partial Decision EB-2012-0064, pgs. 11-14.
[4] Board Staff have incorrectly referenced the decision as EB-2011-0273
[5] HHI Draft Rate Order EB-2011-0173 ICM Workform
[6] 2-Staff-4

through the ICM rate rider[7].

2.9 VECC agrees with Board Staff's submission that the current proposal to include any of the 110kV transformer project into the bridge year should not be approved. This project will clearly not be in-service or used or useful until 2014.

2.10 VECC also submits that is clear the current ICM rate rider will collect in excess of the ICM projects that were forecast to be in-service in 2013. However, it is not clear that the Board established the corresponding variance account for the ICM rate rider. If it did not, and notwithstanding Board Staff's reference to the Filing Guidelines which suggest otherwise, we are uncertain as to whether such a true-up can occur in the absence of a prior established variance accounts[8]. The Board has established in numerous proceedings that utilities cannot apply retrospectively for variance or deferral accounts because from this would follow retroactive ratemaking. Symmetrical reasoning implies the Board cannot (or should not) establish such accounts retrospectively.

2.11 VECC is in agreement with the substance of Board Staff's argument. HHI has clearly over collected the anticipated amount required of the ICM rider. It also agrees that under the ICM model it is anticipated that variances in ICM riders and actual in-service amounts should be subject to reconciliation. Whether in this case the appropriate regulatory vehicles were in place for this to occur is a matter, we submit, for the Board to consider.

Working Capital

2.12 For working capital HHII proposes to use the 13% of controllable costs default methodology set out by the Board. VECC submits that a rate of 12% of controllable costs is more appropriate

[7] 2-VECC-4

[8] Board Staff submission page 9

2.13 As of December 2012 HHI bills all of its customers on a monthly basis[9]. The Board's default rate was established when most utilities offered bi-monthly billing. Utilities that perform monthly billing have a lower need for cash on hand than bi-monthly billing utilities. Monthly billing Utilities, such as London Hydro, which have recently completed lead-lag studies have shown much lower working capital requirements and nearer to 11% of controllable costs.[10]

2.14 While VECC is mindful of the recent decisions we continue to advocate for a review of the working capital default value. The default value is based on aged population of electric distribution utilities that had previously billed on a bi-monthly basis. Over the past four years and with the introduction of smart metering and time-of-use rates billing frequency has changed from bi-monthly to predominantly monthly billing. This change undermines the theoretical premise of the default value.

2.15 It is our view that the current default value of 13% is based on no specific evidence and contrary to evidence reviewed and accepted by the Board in other proceeding. We believe it is incorrect to use an arbitrary proxy rather than tested evidence, even if that evidence was reviewed in other proceedings, but which is the result of actual lead-lag studies.

3 LOAD FORECAST

2014 Forecast Customer Count

3.1 In its revised July 2013 Application, HHI determined the forecast 2014 customer count for each class by applying the historical geometric mean growth rate (2003-2012) to the actual 2012 customer count[11] and then adjusting to reflect any additional known information such as new housing developments[12]. These

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[9] 2-VECC-5
[10] See EB-2012-0146, Exhibit 1, page 42.
[11] Exhibit 3, Tab 1, Schedule 5 (Note: There are no page numbers in Exhibit 43)
[12] Board Staff #13 a)- d)

adjustments primarily impacted the Residential and GS<50 classes where, for 2014, an additional 8 and 10 customers were added respectively to the 2014 forecast based on the geometric growth rate[13]. This forecast was not changed as a result of the interrogatory process[14].

3.2 In response to VECC #12 HHI provided the actual 2013 customer count by class as of June 30, 2013. Apart from the GS<50 class, the reported values appear to be in line with HHI's customer count forecast for 2013. Overall, VECC submits that HHI's forecast customer counts by class for 2014 are reasonable and should be adopted by the Board.

Volume Forecast (Prior to CDM Adjustments)

3.3 HHI's load forecast is effectively prepared in two phases. In the first phase a billed energy forecast by customer class for 2014 is developed reflecting the 2012 customer count. Then, in the second phase, usage associated with the change in customers between 2012 and 2014 is determined and added[15].

3.4 For the first phase, HHI's load forecast is prepared on a total purchase basis using regression analysis. The purchased power model uses weather, seasonal variables and full time employment levels in the Ottawa region as explanatory variables[16]. The overall regression model is fairly robust with a reasonably high Adjusted R Square. However, the employment variable's coefficient has a negative sign, which is counter intuitive, and is not statistically significant[17]. When asked why the variable was retained in the equation, HHI's only rationale was that the variable was used in the last Board Approved Load Forecast[18].

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[13] Exhibit 3, Tab 1, Table 16
[14] 3-VECC-17
[15] HHI does not specifically describe its methodology as being a two-phase approach. However, this effectively what happens, as can be seen in Exhibit 3, Tab 1, Schedule 4 where for each class the 2014 usage initially estimated for class is adjusted in Table 16 to account for the change in customer count between 2012 and 2014.
[16] Exhibit 3, Tab 1, Table 13
[17] Exhibit 3, Tab 1, Table 13
[18] 3-Staff-12 a)

3.5 During the interrogatory process both Board Staff and VECC requested that HHI test alternative purchased power regression models. Board Staff requested[19] that HHI develop a model that excluded the employment variable. The resulting model yielded a slightly lower Adjusted R Square[20]. VECC requested[21] an alternative specification using Residential customer count in lieu of employment. While this second regression model had a higher Adjusted R Square value, the coefficient for the Residential customer count variable was negative, which is also a counter-intuitive result[22].

3.6 For purposes of forecasting 2014 purchases, HHI has used the 2014 values for the seasonal variables along with a nine-year definition of weather normal[23]. However, for the 2014 employment forecast, HHI has used the average of the historical employment levels over the 2003-2012[24]. This 2014 purchase power forecast was then allocated to major customer classes (Residential, GS<50 and GS>50) based on each retail class' 2012 share (i.e. %) of 2012 actual purchases[25].

3.7 For the second phase, the preceding results were used to determine an average use per customer for each of the major customer classes[26]. These values were then multiplied by the increase in customers for each class to determine the increase in load from new customers added between 2012 and 2014 and added to the each of the retail class' energy values determined earlier[27].

3.8 Various alternative approaches were used for each of the other three customer

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19 3-Staff-12 c)
20 Excel Worksheet filed November 12, 2013 – see Regression Calculations Tab
21 VECC #14 a). A supporting Excel Worksheet was also filed on November 12, 2013
22 One would expect power purchases to increase as either customer count or employment levels increase.
23 Exhibit 3, Tab 1, Table 11
24 3-VECC-13
25 Exhibit 3, Tables 17-19

classes[28]. For Street Lighting 2014 energy and billing demand were determined by multiplying the forecast number of 2014 connections by the historical average kWh and kW per connection respectively. For Sentinel Lights, 2014 energy and billing demand were based on the average historical values for each over the 2004-2012 periods. Finally, for USL 2014 energy was based on the forecast number of connections multiplied by the average historical use per connection.

3.9 In VECC's view, this overall approach is reasonable provided:

- The forecast 2014 purchases (and resulting usage for the major customer classes) determined in phase 1 reflect the purchases HHI could expect in 2014 assuming no growth in customers after 2012, and
- The customer additions used in the second phase account for all forecast customer growth between 2012 and 2014.

3.10 The only variable in HHI's regression equation that is reflective of changes in number of customers and/or usage per customer over time is the "economic conditions" variable – employment in the Ottawa region. As a result, the economic conditions reflected in the (phase 1) 2014 purchase power forecast should be those existing at the close of 2012. They should not reflect any of the employment growth currently forecast for 2013 and 2014[29]. On the other hand, they should not be based on average employment levels over the past 10 years which is what HHI has used in preparing the forecast[30].

3.11 The difference is material. Based on the values used in HHI's Load Forecast model the Ottawa Region employment level as of December 2012 was 567.50. In comparison the average of the monthly employment values that HHI has used in its 2014 purchased power forecast is 482.4[31]. Furthermore, if one replaces the

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[26] Residential, GS<50 and GS>50
[27] Exhibit 3, Tab 1, pages 21-27
[28] Excel Load Forecast Worksheet_20130530, Worksheet-Class Analysis Tab
[29] 3-VECC-13
[30] 3-VECC-13
[31] This value was calculated as the average of the January 2014 to December 2014 Ottawa Region employment values from HHI's Load Forecast Worksheet_20131530 – Tab: Input WS Regression Analysis

2014 employment values used by HHI with 567.5 for each month of 2014 VECC estimates that the resulting purchased energy forecast to be 162.73 GWh versus the 164.69 GWh forecast developed by HHI[32]. It should also be noted that the use of the higher employment level (567.5) results in a lower purchased energy forecast due to the (counterintuitive) negative coefficient estimated for "employment" by the regression analysis – as discussed previously.

3.12 In VECC's view, while the regression equation estimated by HHI is flawed the distortion caused by these flaws is reduced when the equation is used to estimate 2014 purchases assuming no further change in employment levels. Furthermore, the result (162.73 GWh) is fairly similar to the 163.41 GWh projection for 2014 that which results[33] from using the regression equation without any employment variable developed in response to Board Staff interrogatories[34].

3.13 VECC submits that, for purposes of phase 1 of its load forecast methodology, HHI should use a 2014 purchase power forecast in the range produced by these two forecasts and considers 163 GWh to be a reasonable value.

3.14 In phase 2, VECC notes that for its 2014 forecast HHI has only used the new customers forecasted be added in 2014 and omitted those added in 2013. For example, while the total 2012-2014 increase in customer count for the Residential class is 81[35], the number of new 2014 customers used in making the adjustment is only 45[36]. A similar problem exists for the GS<50 class. Furthermore, in the case of the GS>50 class there is no recognition of the additional four customers expected in 2014[37].

3.15 Also, contrary to the heading used in Exhibit 3, Table 17, HHI has not used the

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[32] This calculation was performed by replacing (in HHI's Load Forecast Worksheet_20130530 – Tab: Input WS Regression Analysis) the 2014 employment values used by HHI with 567.5 for each month. The supporting model run is available upon request.
[33] Load Forecast Worksheet_Nov 6 Scenario1_Employment Var Removed_20131112 – Input WS Regression Analysis Tab
[34] 3-Staff-12 c)
[35] Exhibit 3, Tab 1, Table 16
[36] Exhibit 3, Tab 1, Table 17
[37] Exhibit 3, Tab 1, Tables 16 and 19

2012 customer count to determine the average use per customer for purposes of in calculating the average use per customer to apply to the increase in customers between 2012 and 2014. Rather, HHI has used the 2014 customer count forecast based on the geometric mean which results in an understatement of the average use[38]. However, correcting the number of customers used to determine the average use would only result in small increase for each of these classes.

3.16 In VECC's view, the load forecast should (at minimum) use the expected number of total new customer additions between 2012 and 2014 for each of the Residential, GS<50 and GS>50 classes in determining the increase in billed energy for 2014.

Volume Forecast (Including CDM Adjustment)

3.17 In its initial Application, HHI included in its CDM adjustment the impact anticipated in 2014 from CDM programs implemented in 2011 through 2014[39]. While HHI did apply the ½ year rule to the 2014 program savings, it also adjusted the results for all years so that they reflected gross (as opposed to net) CDM savings such that the resulting CDM adjustment was 6,782,178.05 kWh[40].

3.18 During the interrogatory process HHI acknowledged that, in accordance with the Board's Guidelines, the 2011 and 2012 CDM savings (totalling 2,011,586 kWh on a gross CDM basis) should not be included in the manual adjustment as they are already captured in the 2003-2012 historical data used by HHII to develop its load forecast model[41]. However, HHI is not proposing to alter its CDM adjustment and resulting load forecast accordingly[42]. HHI's position appears to be that since the Board Guidelines were issued after its Application was filed it does not have to follow them, unless explicitly directed to do so by the Board[43].

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[38] This can be observed from HHI's Load Forecast Worksheet_20131530 – Tab: Worksheet-Class Analysis
[39] Exhibit 3, Tab 1, Table 26
[40] Exhibit 3, Tab 1, Table 26
[41] 3-VECC-17 c)
[42] 3-VECC-19
[43] 3-VECC-19 e)

3.19 VECC disagrees. VECC notes that the Board's Decisions regarding 2013 rates for both Sioux Lookout and Centre Wellington, excluded CDM impacts from programs implemented in years covered by the historical data used to develop the initial (pre-CDM forecast) and sees no reason why HHI should not have, in responding to interrogatories, assumed that the same approach should be applied to it for 2014 rates.

3.20 VECC submits that the Board should direct HHI to exclude impacts of 2011 and 2012 CDM programs from its manual CDM adjustment for 2014.

3.21 With respect to the gross versus net adjustment, the Board has clearly indicated its position in its Decision regarding Centre Wellington's 2013 rates[44] and, subsequently, confirmed that net was the appropriate approach in its Decision regarding Sioux Lookout's 2013 rates[45]. VECC submits that the Board should direct HHI to use net CDM impacts in the determination of the manual CDM adjustment for 2014.

3.22 In response to Board Staff #15 a), HHI has provided a CDM adjustment calculation that includes the impact in 2014 based on ½ of the 2012 program savings, the full impact of 2013 program savings and ½ of the 2014 program savings for a total of 2,519,317 kWh. In the Decision regarding Sioux Lookout Hydro[46], the Board explicitly rejected Board Staff's proposal at that time to include the ½ year impact for the most recent actual results (in that case 2011 for 2013 rates). As a result, VECC submits there should be no ½ year adjustment of 342,623.5 kWh for 2012 programs. The resulting manual CDM adjustment would be 2,176,693.5 kWh.

3.23 Finally, VECC notes that the cumulative savings from 2011 and 2012 programs presented in the response to Board Staff #15 (and VECC #17 a) of 4,926,613 kWh(2,870,872+2,055,741) do not match the cumulative savings for the two years as reported by the OPA in its final 2012 Report of 4,887,421 kWh[47]. HHI may wish

[44] Board Decision, EB-2012-0113, page 7
[45] Board Decision, EB-2012-0165, page 7
[46] EB-2012-0165, page 6
[47] HHI Verified Annual 2012 CDM Report filed on November 6, 2013

to comment on the discrepancy in its reply submissions.

3.24 Subject to any adjustments required to align HHI's annual CDM savings as reported in Board Staff #15 with the OPA's final 2012 CDM Report, VECC agrees with HHI's proposed 2014 LRAMVA kWh amounts as set out in that response.

4 REVENUE OFFSET

4.1 The projected 2014 revenue offsets in HHI's Application are $157,139[48]. This value has remained unchanged throughout the interrogatory process.

4.2 During the interrogatory process HHI confirmed that revenues forecast from Interest and Dividend Income included carrying charges on the RSVA accounts[49]. Contrary to HHI's response, it is VECC's understanding that these carrying charges should not be included as a revenue offset as they are "booked" and refunded to customers via the appropriate RSVA accounts.

5 OPERATING COSTS

5.1 The 2010 OM&A increase to 2014 is 19% when compared to the last Board approved, or 30% if compared to the actual 2010 OM&A spent.

5.2 VECC performs an "expected growth test" for cost of service filers. This exercise asks the question what would a utility's OM&A costs been had 2010 costs been adjusted for only for customer growth and inflation. To this figure we add the cost of any incremental responsibilities taken on by the utility since the last rebasing.

5.3 HHI's customer growth to the 2014 is forecast to be approximately 3.4%. For inflation VECC has used widely available Statistics Canada figures for 2010 through 2012 which are 1.78%/2.91%/1.52% respectively. 2013 inflation is currently running at approximately 1.0%. Simple addition would indicate an

48 Exhibit 3, Tab 3, Schedule 2, Appendix 2-F
49 3-VECC-20 b)

expected inflationary growth of 7.3%[50].

5.4 The result is that all other things being equal one would expect the OM&A budget to have increase by between 10% and 11% for simply customer growth and inflation.

5.5 To this range one needs to apply both a productivity offset and a stretch factor for the IRM period. Applying the productivity offsets of 0.72% as provided by the Board's IRM policy over the four year period would reduce the expected growth by approximately 3% (288 basis points). VECC submits a productivity offset is an appropriate adjustment as it simply embeds the assumed efficiencies of the IRM period.

5.6 The IRM stretch factor should also be incorporated into the calculation of the expected growth factor. HHI had a specific stretch factor of 0.2%.[51] This would further reduce the expected growth by approximately 0.8 % (80 basis points).

5.7 In total an adjustment of 368 basis points or approximately 3.7% should be made to the expected growth figure. This results in an expected OM&A growth of between 6.3% and 7.3%. Using an approximate figure of 7% one would expect an increase in OM&A of between $60,738 to $66,191 depending on whether the starting point is the Board approved 2010 amount of the actual spent in that year.

5.8 HHI has identified $92,921 in on-going smart meter costs. However, this figure does not net out the $21,000 reduction in manual meter reads.[52] The net incremental costs for smart meters are therefore $71,921.

5.9 No other incremental responsibilities were identified by HHI. Its FTE count is identical in 2010 and 2014 and its regulatory costs are slightly, but not significantly higher.

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[50] See Statcan.ga.ca
[51] Board Decision EB-2012-0134, pg. 3
[52] 4.0-VECC-24 and 4-VECC-27

5.10 The total increase in OM&A VECC submits should be $1,083,704 (945,592 + 66,191 + 71,921) if based on a starting point of 2010 Board Approved; and $1,000,348 (867,689 + 60,738 + 71,921) if based on 2010 actual spending This is a reduction of between $126,665 and $42,961.

5.11 In VECC's submission a simple rounding and average of these figures or a reduction of $85,000 would represent a reasonable, if not modest reduction in the proposed OM&A.

5.12 In support of these reductions VECC notes that HHI updated it's expected 2013 OM&A to $1,384,949 or a reduction of $44,532 or 3% of its forecast budget[53].

5.13 VECC also notes that the actual Bad Debt component (Account 5335) has ranged between $19,528 and $2,800 between 2010 and 2012. In 2014 HHI is proposing $30,000 in bad debt costs be built into ongoing rates. [54]

5.14 Furthermore HHI has noted that it has forecast $16,000 in EDA fees for 2014. VECC has noted that such shareholder "lobbying" fees should not be recoverable from ratepayers. Reduction of just these three simple items would result in lowering the OM&A budget by approximately $70,000 to $80,000.

5.15 VECC also notes that HHI proposes to increase management compensation by 17% as between 2012 and 2014 whereas union staff compensation will only increase by 6%. When queried by VECC as to the reasons for this discrepancy HHI indicated it was relying on a MEARIE Group Management Salary Study, but it did not file this report.

5.16 The point of these latter submissions is not to second guess HHI's OM&A priorities. Rather we believe it demonstrates that the evidence supports the view that an $85,000 reduction in OM&A is modest, reasonable and would not subject the Utility to undue hardship. How HHI makes that reduction should, in our submission, be left to the discretion of HHI management.

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[53] 4.0-VECC-23
[54] Appendix 2-H, HHI_2014 Chapter 2 Appendices

6 COST OF CAPITAL / CAPITAL STRUCTURE

6.1 VECC agrees with Board Staff that HHI should update the cost of capital parameters to reflect the Board's most recent values. VECC has no other submissions on this issue.

7 COST ALLOCATION

Cost Allocation Methodology

7.1 In its Application, HHI has used the latest Board approved Cost Allocation model[55]. HHI also indicates that it has used LDC specific weighting factors for Services and Billing & Collecting, as directed by the Board[56].

7.2 During the interrogatory process, HHI filed a revised Cost Allocation model that aligned its meter capital costs by customer class with its incurred smart meter costs and corrected the meter reading weighting factors used for Residential and GS<50[57].

7.3 However, for purposes of establishing the load profiles and resulting demand allocation factors for each customer class, HHI has used the same kW values as in its last (2010) cost of service application[58]. VECC notes that while most electricity distributors continue to rely on the load profiles developed by Hydro One for their 2006 informational filings, the standard practice is to apply this profile to the load forecast (kWh) proposed in their rate application in order to derive the kW values used in the cost allocation model (Sheet I9) that are consistent with the load forecast. However, HHI has not done this but rather continued to use the same kW values as in forecast for 2010 in its EB-2009-0186 Application. As a

[55] Exhibit 7, Tab 1, page 5
[56] Exhibit 7, Tab 1, page 5
[57] 7-VECC-40 a)and b)
[58] 7-VECC-39 b). VECC has also reviewed the Cost Allocation model filed with HHI's 2010 Rate Application (EB-2009-0186) and confirmed that the values used in Tab I9 of that model are exactly the same as those used in the current Application.

result, the kW values used by HHI in its 2014 cost allocation model are not aligned with its 2014 load forecast.

7.4 In its submissions Board Staff points out[59] that HHI has changed the weighting factors used for purposes of allocating Billing and Collecting costs – which represent just under ½ of total O&M expenses. The implication being that the cost allocation has been improved. However, VECC disagrees. Over 50% of the distribution plant fixed assets are allocated on the basis of demand[60] . As a result, the use of incorrect demand allocators, as previously noted, is a serious flaw. While HHI argues[61] that loads have not changed materially since 2010, the load growth for all classes has not been the same between 2010 and 2014. The result is that while the current cost allocation may provide indicative revenue to cost ratios, it cannot be viewed as providing accurate results as to what the 100% revenue to cost ratio would be for each class.

7.5 Given this deficiency, VECC submits that the methodology/model is clearly not sufficiently improved to justify the moving the revenue to cost ratio closer to 100% than is currently required by the March 2011 Report the Board ("Review of Distributor Cost Allocation", EB-2010-0219).

Use of the Cost Allocation Study Results in Setting 2014 Rates

7.6 The following table sets out the 2013 Status Quo Revenue to Cost (R/C) ratios for each customer class based on the Cost Allocation model filed by HHI with its interrogatory responses and the ratios proposed by HHI for 2014 in revised Appendix 2-P also filed at the same time[62].

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[59] Board Staff Submissions, page 16
[60] Cost Allocation Model, Sheet O6
[61] 7-VECC-39 c)
[62] 7-VECC-41. See also HHI_2014 COS Cost Allocation Model V3_20131106 and HHI_2014 Chapter 2 Appendices_20131106

REVENUE TO COST RATIOS – STATUS QUO AND PROPOSED per REVISED APPLICATION		
Customer Class	**2013 Status Quo R/C Ratios**	**2013 Proposed R/C Ratios**
Residential	101.82%	100.00%
GS<50	107.80%	100.00%
GS 50-4999	87.44%	100.00%
Street Lighting	167.72%	100.00%
Sentinel Lighting	146.95%	100.00
USL	104.41%	99.92%

Notes: Per Updated Appendix 2-P, filed November 6, 2013

7.7 The Status Quo R/C ratios for Street Lighting and Sentinel Lighting are both outside (above) the Board's 120% policy guideline for each and clearly should be reduced. The issue for the Board is by how much and, correspondingly, by how much should the R/C ratios for Residential and Street Lighting be increased in order to maintain revenue neutrality.

7.8 In its November 2007 Report (Application of Cost Allocation for Electricity Distributors, EB-2007-0667) the Board expressed the following views[63]:

> *Distributors should endeavour to move their revenue-to-cost ratios closer to one <u>if this is supported by improved cost allocations</u>. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. <u>Distributors should not move their revenue-to-cost ratios further away from one</u> (emphasis added).*

7.9 In its March 2011 Report (EB-2010-0219) the Board set out target ranges for revenue to cost ratios for each customer class[64]. In that same Report the Board stated:

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[63] Board Decision EB-2007-0667, page 7
[64] Ibid, page 36. See also Exhibit 7, Schedule 2, page 3 of the Application

As indicated in its September 2, 2010 letter, the Board expects that with the installation of smart meters and the availability of sufficient smart meter data, better cost allocators for the CA Model will become available and a more comprehensive review of the Board's cost allocation policies will become feasible. The Board anticipates that such a comprehensive review may provide an opportunity to further refine its target ranges. In the meantime, the Board's policy remains that distributors should endeavour to move their revenue-to-cost ratios closer to one <u>if this is supported by improved cost allocations</u> (emphasis added).

7.10 In its Decision regarding Toronto Hydro's 2011 rates[65], the Board made the following findings regarding the application of this policy:

The Board finds that the proposed revenue-to-cost ratios are not appropriate and are not consistent with the Board's revenue-to-cost policy report (EB-2007-0667). In that report, the Board set out that an incremental approach is appropriate and that a range approach is preferable to implementation of a specific revenue-to-cost ratio. The Board also stated that distributors should endeavour to move their revenue-to-cost ratio closer to one if this is supported by improved cost allocations. THESL did not file updated or improved cost allocation information and continues to rely on 2006 information to define the load profiles for certain customer classes.

Based on these findings and those set out above, the Board directs THESL to recalculate the starting revenue-to-cost ratios by customer class. For those customer classes with starting revenue-to-cost ratios greater than or less than the upper or lower end of the range provided by the Board in EB-2007-0667, THESL is directed <u>to move the customer class ratio to the upper or lower boundary, as appropriate, and to adjust other class ratios only as required to reconcile with the overall approved revenue requirement</u> (emphasis added).

7.11 Similarly, in its Decision regarding Horizon's 2011 Rates the Board made the following findings[66]:

The Board finds, however, that the proposed revenue-to-cost ratios are not appropriate and not consistent with the Board's revenue to cost policy, which establishes ranges of tolerance around revenue-to-cost ratios of one and adopts an incremental approach, whereby changes to revenue-to-cost ratios within the range are to be supported by improvements to the cost allocation model.

The Board is of the view that updating the pre-existing cost allocation model with test year data is an insufficient "improvement" for the purpose of supporting the movement within class ranges, as the Board recognizes that the results will vary somewhat due to data limitations and volatility.

For those customer classes with starting revenue-to-cost ratios greater or less than the upper or lower end of the range provided by the Board in EB-2007-0667,

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[65] July 7, 2011 Decision, EB-2010-0142,page 40

[66] July 7, 2011 Decision, EB-2010-0131, page 43

Horizon is directed to move the customer class ratio to the upper or lower boundary, as appropriate, and to adjust the other class ratios only as required to reconcile with the overall approved revenue requirement (emphasis added).

7.12 VECC's following submissions are based on the application of the principles as set out in these Reports and Decisions. First, as noted in the preceding paragraphs the load data used by HHI in its cost allocation model is flawed. As a result, VECC submits that HHI's cost allocation does not reflect any real improvement (and indeed may be less accurate) over that used for its 2006 Informational Filing or its 2010 Rate Application. Given the state of its cost allocation model along with the policies outlined in the Board's 2007 and 2011 Reports and the previous Decisions cited above, VECC submits that the ratios for Street Lighting and Sentinel Lights should be reduced – but only to the upper end of the Board's respective policy range for each class. Furthermore, apart from increasing the GS>50 ratio so as to maintain revenue neutrality, the ratios for the other classes should remain unchanged and not moved to 100% as proposed by HHI.

RATE DESIGN

Base Distribution Rates

7.13 HHI states[67] that it has adjusted the fixed charges taking into consideration various factors such as equity between the fixed and variable rate, impact on customers as well as revenue stability.

7.14 For the Street Lighting, Sentinel Lighting and USL classes HHI claims that its proposal is to move the fixed/variable split closer to a 50% fixed and 50% variable split[68]. When asked about the rationale for such a proposal HHI stated[69]:

If a utility had a choice, they would select a 100% fixed and 0% variable to ensure revenue stability. If a customer had a choice, they would select a 100% variable so that they could have full control over the cost of their hydro bills. A 50/50 split ensures that both the customer and the utility's needs are met.

7.15 In its 2007 Cost Allocation Review Report the Board did not establish any specific

[67] Exhibit 8, Tab 1, page 10
[68] Exhibit 8, Tab 1, page 10
[69] 8-VECC-44 a)

approach that electricity distributor should adopt in setting their fixed-variable splits for purposes of rate design but did conclude that[70]:

The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time, given the number of issues that remain to be examined. The appropriateness of the methodologies cited above, used to set the MSC is an issue that will be examined within the scope of the Rate Review. The Rate Review will also examine the role of rate design in achieving various objectives, including conservation of energy. Both of these undertakings will have determinative impacts on the fixed/variable ratio policy.
In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time.

7.16 VECC has consistently argued in previous proceedings regarding cost of service based rate applications that, in line with the Board's intent not to make significant changes until it has completed its Rate Review (including the fixed/variable ratio policy), the current fixed variable split should be maintained unless it results in a fixed charge that exceeds the ceiling established by the Cost Allocation model. In such circumstances, it is VECC's view that the fixed charge should be capped at the greater of the ceiling or the current value, consistent with the Board's stated policy.

7.17 To date, the Board's general approach has been to approve proposed service charges based on a utility's existing fixed/variable split even when this results in increases to fixed charges such that the results will exceed the ceiling established by the Cost Allocation model[71]. While VECC does not completely agree with this approach VECC understands the attractiveness in maintaining the status quo fixed variable ratio until its currently planned Rate Review has been completed.

7.18 However, HHI's proposal does not adopt either of these approaches for these three customer classes and, indeed, adopts a totally different view of what should

[70] Pages 12-13
[71] The Board has also accepted proposals by electricity distributors to limit their monthly service charges to current levels when those exceed the ceiling for the MSC

be considered "fair rates". VECC also notes that HHI's definition of fairness departs significantly from the "cost-based" approach generally used by the Board in setting rates.

7.19 Furthermore, the fixed variable splits actually proposed for the Street Lighting and Sentinel Lighting classes are not only materially different from the status quo[72] but, in both cases, increase the fixed ratio significantly above the stated 50% objective (29.36% to 70.78% in the case of Street Lighting and 30.35% to 69.94% in the case of Sentinel Lighting). VECC submits that that for these three classes the primary objective appears to be increased revenue stability.

7.20 In the case of the Residential class, HHI notes that its current MSC is the lowest in Ontario[73]. However, this is no indication that its rate design is unfair as its variable charge is the second lowest in Ontario. Again, HHI's proposal to increase its Residential fixed charge recovery from 45% to 64% runs counter to its stated its stated definition of fairness and appears to be based solely on "ensuring a level of revenue stability for the utility"[74].

7.21 VECC notes that, as part of the Renewed Regulatory Framework for Electricity, the Board has initiated a project (EB-2012-0410) to complete the work begun in EB-2010-0060 regarding revenue decoupling for electricity and natural gas distributors. Furthermore, it is VECC's understanding that this project is specifically looking at rate design as it pertains to revenue decoupling and revenue stability. In VECC's view, to accept HHI's proposals and associated rationale with respect to these four customer classes would establish a precedent that other utilities may seek to follow. The changes (and supporting rationale) proposed by HHI should not be adopted by the Board at this time. These are the types of changes that are more properly considered as part of the Board's pending Rate Review.

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[72] See Appendix B-Rate Design filed with the interrogatory responses
[73] Exhibit 8, Tab 1, page 11
[74] Exhibit 8, Tab 1, page 11

7.22 For all four of these classes (i.e., Street Lighting, Sentinel Lighting, USL and Residential) HHI should be directed to base its rate design for base distribution rates on the current fixed-variable split for each customer class. VECC further notes that, based on HHI's evidence, the resulting fixed charges should all be below the respective ceilings established by Board policy[75].

7.23 In the case of the GS<50 class HHI proposal marginally decreases the fixed charge percentage from 50% to 48.5% and, therefore, actually runs counter to both its fairness and revenue stability objectives. Again, in VECC's view, the current fixed / variable split should be maintained for this class as well.

7.24 Finally, in the case of the GS>50 class the current fixed charge ($97.35) is materially higher than the maximum value calculated by the Cost Allocation model[76] ($26.50). HHI proposes to maintain the fixed charge at this level for 2014. This approach is consistent with the Board's stated policy and should be approved by the Board.

Loss Factors

7.25 HHI has used a five year historical average to determine its proposed loss factors[77]. VECC notes that the distribution loss factors have been generally declining over the five year period and submits that a distribution loss factor calculated over a shorter period such as three years would be more appropriate.

7.26 Board Staff[78] has taken exception to HHI's proposed Supply Facility Loss Factor (SFLF) of 1.0058. Board Staff notes that roughly half of HHI's load is supplied by Hydro One Networks and suggests that the applicable SFLF should be about one-half of the default SFLF of 1.034. VECC notes that this issue was not explored during the interrogatory process and there is no information on the record as to what the actual loss factors used by Hydro One Networks in billing HHI are.

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[75] See Appendix B-Rate Design filed with the interrogatory responses
[76] See Appendix B-Rate Design filed with the interrogatory responses
[77] Exhibit 8, Tab 6, Appendix 2-R
[78] Board Staff Submissions, pg. 23

However, in Exhibit 1[79], HHI indicates that its connection to/supply from Hydro One Networks is via a 44 kV line.

7.27 VECC submits that the supply facility losses for such a facility would be less than those experienced by a distributor embedded with Hydro One Networks that also utilized one of its host's distribution stations. As a result, it is not immediately apparent that the 1.0058 factor is inappropriate.

Retail Transmission Service Rates

7.28 During the interrogatory process HHI updated[80] the Board's RTSR Model to incorporate the latest Uniform Transmission Rates and Hydro One Sub-Transmission Rates. VECC submits that these revised rates should be approved by the Board.

Low Voltage Rates

7.29 HHI has based its 2014 LV costs ($97,698) on historical charges[81]. While the forecast could be refined the value is reasonable for rate setting given any differences will be captured in a variance account.

Specific Charges

7.30 HHI is proposing[82] to increase its specific service charges for i) Change of Occupancy Charge ($30 to $40); ii) Disconnect/Reconnect at Meter – After Regular Hours ($130 to $170); iii) Install/Remove Load Control Device – After Regular Hours ($130 to $170) and iv) Service Call – After Regular Hours ($130 to $170). In each case HHI has provided a calculation as to the actual costs of providing the service.

7.31 VECC agrees that the current charges for these services are insufficient. However, it notes that for those three changes relating to services provided after regular hours the cost is $162.50 in each case. Based on this cost, VECC submits

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[79] Tab 1, page 25
[80] 8-Staff-27

it would be more appropriate to set the new charge for each of these services at $165.

8 DEFERRAL AND VARIANCE ACCOUNTS

LRAM Recovery

8.1 Board Staff has made extensive submission in respect to the proposal to recover a residual $1,423 balance. While the amount in question is not material the principles and argument of Board Staff are sound and we support them.

Smart Meters

8.2 VECC supports HHI's proposed stranded meter rate rider shown below.

Table 9: Stranded Meter Rate Rider

Customer Class Name	Net Book Value	Smart Meters Installed	% share	Annual $	Customer	Rate	per month
Residential	$54,894.20	4803	89.26%	27,447.10	4950	$5.54	$0.46
General Service < 50 kW	$6,606.05	578	10.74%	3,303.02	168	$19.66	$1.64
General Service > 50 to 4999 kW							
	TOTAL	**5381**					

Total for Recovery				**61,500**
Recovery Period (years)			**2**	
Annual Recovery				**30,750**

[81] Exhibit 8, Tab 5
[82] Exhibit 3, Tab 3, Schedule 5

9 EFFECTIVE DATE

9.1 HHI proposes a January 1, 2014 implementation date. VECC has no objection to this proposal if the regulatory process can be completed in sufficient time. If not, VECC submits that there should be no retroactive recovery of the proposed revenue recovery.

10 RECOVERY OF REASONABLY INCURRED COSTS

10.1 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.

All of which is respectfully submitted this 9th day of December 2013.