February 5, 2010

BY EMAIL & COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St, Suite 2701
Toronto ON M4P 1E4

Dear Ms. Walli:

Board File No. EB-2009-0096
Hydro One Networks Inc. – 2010 & 2011 Rates Application
Argument of Energy Probe

Pursuant to the letter from the Board earlier today confirming the argument schedule, please find attached two hard copies of the Argument of Energy Probe Research Foundation (Energy Probe) in the EB-2009-0096 proceeding for the Board's consideration. An electronic version of this communication will be forwarded in PDF format.

Should you require additional information, please do not hesitate to contact me.

Yours truly,

David S. MacIntosh
Case Manager

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EB-2009-0096

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution for 2010 and 2011.

Final Argument On Behalf Of

Energy Probe Research Foundation

February 5, 2010

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Final Argument On Behalf Of

Energy Probe Research Foundation

How these Matters came before the Board

1. On July 30, 2009, Hydro One Networks Inc. (the "Applicant" or "Hydro One"), filed an Application seeking approval for changes to the rates that it charges for electricity distribution, to be effective January 1, 2010 and January 1, 2011. The Board issued a Notice of Application and Hearing on August 4, 2009. Energy Probe filed a Notice of Intervention on August 10, 2009, as a full time intervenor.

2. Energy Probe participated in extensive pre-hearing consultations with Hydro One prior to the Application being filed with the Board. These consultations were well organized and the relevant information was well presented, resulting in a much reduced overall scope for the hearing, substantially enhanced information being brought forward to the Board by the applicant, and a better informed stakeholder community. Energy Probe appreciated the Hydro One consultation process.

3. Procedural Order No. 1 was issued by the Board on September 9, 2009 and provided both a Proposed Issues List and a procedural schedule for the proceeding. Parties were encouraged to make submissions on the proposed issues list.

4. Energy Probe filed submissions on the proposed issues list on September 14, 2009, and filed reply submissions in respect of intervenors' and the Applicant's submissions on September 18, 2009.

5. The Applicant filed an update to its evidence on September 25, 2009.

6. **The Issues Decision and Procedural Order No. 2 was issued by the Board on September 25, 2009. Energy Probe filed Part One of its Interrogatories on September 25, 2009, and filed Part Two of its Interrogatories on October 2, 2009.**

7. **Energy Probe actively participated in a short Settlement Conference on November 18, 2009.**

8. **Energy Probe did take part in the Oral Hearing, including cross examination of witnesses, from December 7-18, 2009. The Oral Hearing reconvened on January 11, 2009 with Energy Probe in attendance.**

Argument Overview

9. **Energy Probe has conducted itself as an all issues intervenor throughout this proceeding.**

10. **In its Argument, Energy Probe will not seek to explore all outstanding Issues before the Board, but will be examining those Issues of concern to Energy Probe where we believe we can be of most assistance to the Board, and has addressed some matters that might not be as thoroughly canvassed by other consumer-oriented groups.**

General

Issue 1.2 **Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?**

11. **The clear answer to this question is no, Hydro One's economic and business planning assumptions for 2010/2011 are not appropriate. As shown in Exhibit A, Tab 14, Schedule 3, Hydro One's economic and business planning assumptions were based on Global Insight's December 2008 forecast. The Board is aware that a lot has changed since then. After all, the Board initiated a consultation process on**

March 16, 2009 to "determine whether current economic and financial market conditions" warranted any adjustments to the cost of capital parameters. The EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities found that significant changes were required. These changes have been driven by the economic and financial changes that took place beginning in late 2008.

12 The cost of capital parameters has been updated to reflect current outlooks as of September, 2009. This is implicit in the return on equity and short-term debt rates utilized in the responses to Exhibits J4.4 and J4.6. Energy Probe submits that the Board should direct Hydro One to update the forecast for the long-term debt to be issued in 2010 and 2011 to reflect a consistent forecast from September, 2009 that has been used to both determine the short-term debt rate and the return on equity. Energy Probe provides more submissions on this specific topic under Issue 5.2 below.

13. Similarly, Energy Probe submits that the interest rate application to construction work-in-progress should also be updated to reflect the September, 2009 outlook, consistent with the other financial parameter forecasts used. This issue is discussed in more detail under Issue 4.2 under the subheading "Allowance for Funds Used During Construction".

14. Aside from the interest rate forecasts provided in Exhibit A, Tab 14, Schedule 3, the most significant forecasts provided by Hydro One and used in their economic and business assumptions are the inflation rates shown in Table 1. These two inflation rates are the distribution cost escalation for construction and the distribution cost escalation for operations & maintenance. As these inflation indexes indicate, they are very specific to the distribution industry. In the response to Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 1), Hydro One provided an update to these two distribution cost escalators based on the most recent Global Insight forecast available - August, 2009.

15. The following tables illustrate the change in the forecasted inflation rates for 2009 through 2011.

Distribution Cost Escalation for Construction

	2009	2010	2011	Compound Average
Original (Ex. A, Tab 14, Sch. 3)	1.8%	1.3%	1.3%	1.5%
Updated (Ex. H, Tab 3, Sch. 1)	0.9%	-0.1%	1.4%	0.7%

Distribution Cost Escalation for Operations & Maintenance

	2009	2010	2011	Compound Average
Original (Ex. A, Tab 14, Sch. 3)	2.7%	-0.1%	1.0%	1.2%
Updated (Ex. H, Tab 3, Sch. 1)	-2.3%	0.1%	2.3%	0.0%

16. As the above table illustrates, the construction cost escalator over the forecast period has been cut in half based on the updated forecast of Global Insight. This reduction is mainly the result of a decrease in 2009 and 2010. The operations & maintenance cost escalator over the three year forecast period has been reduced from 1.2% per year, to 0%. Again the decrease is based in 2009, with a 5 percentage point decline in the forecast. The 2010 increase remains weak.

17. Energy Probe submits that these weak cost increases relative to that originally forecast in 2009 and 2010 are completely expected. They are the direct result of the economic recession. This is no different than the fluctuation seen over this same period in the forecast for interest rates. Indeed, as noted under the subheading "Forecast Long-Term Debt for 2010 and 2011 Issuances" under Issue 5.2 below, the Hydro One credit spread has fallen by 101 basis points for a 5 year issue, 94 basis points for a 10 year issue and 89 basis points for a 30 year issue. In other words, the decline in the cost escalators is consistent with the decline in the credit spreads. Both declines should be reflected in the revenue requirement.

LOAD and REVENUE FORECAST

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

18. Energy Probe accepts the load forecast and methodology as being appropriate with one exception. That exception is related to the CDM adjustments made to the forecasts, as illustrated in Table 4 of Exhibit A, Tab 14, Schedule 4. Based on the response to an interrogatory (Exhibit H, Tab 3, Schedule 8), Energy Probe submits that Hydro One has correctly accounted for the historical CDM volumes used to forecast the volumes prior to the adjustment for CDM.

19. As shown in Table 4 of Exhibit A, Tab 14, Schedule 4, the forecasted CDM reduction to the load forecast has been increasing in 2006 through 2009. In 2009, the impact of CDM is approximately 2.6% of the load before deducting the impact of CDM. This impact is projected to grow to 5.8% in 2010 and to 7.0% in 2011. Energy Probe has no submissions related to the quantum of CDM forecast as load reductions by Hydro One. Energy Probe's concerns revolve around the inability to accurately forecast and track actual CDM volumes.

20. Variances in the amount of CDM achieved in each year, along with variances in CDM that is maintained from previous years can have a significant impact on the revenue requirement. As indicated in the response at Exhibit H, Tab 2, Schedule 3, the revenue impact is about $2 million for every 100 GWh of CDM. Hydro One is forecasting 2,360 GWh and 2,853 GWh, respectively, for 2010 and 2011. A 5% forecast error on these figures would result in revenue impacts in excess of $2 million in each year.

21. Given the uncertainty around the level of CDM and the significant revenue impact associated with the level of CDM, Energy Probe submits that the Board may wish to consider the establishment of an LRAM account in which to track the variance in CDM as compared to that included in the forecast.

Issue 2.2 Is the proposed amount for 2010/2011 external revenues, including the methodology used to cost and price these services, appropriate?

22. Based on the updated filing of September 25, 2009, Hydro One is forecasting external revenues of $48 million in each of 2010 and 2011 (Exhibit E1, Tab1, Schedule 1, Table 4). The composition of these amounts is provided in greater detail in Exhibit E1, Tab 1, Schedule 2, also updated as of September 25, 2009.

23. As shown in Table 1 of Exhibit E1, Tab 1, Schedule 2, regulated revenues are forecast at $30.6 million in 2010 and $30.4 million in 2011. The average regulated revenues shown for the last three years (2007 through 2009) average just over $29.8 million per year. Increases in some of the components of this regulated revenue have increased, while others have decreased, resulting in flat revenues. Energy Probe accepts the regulated revenues as forecast in Table 1 as being appropriate.

24. Table 2 of Exhibit E1, Tab 1, Schedule 2 shows unregulated revenues that are included in external revenues. The forecast for 2010 is $17.6 million and for 2011 is $17.7 million. These revenues have been increasing since 2006 when the actual amount was $11.6 million. In 2008, actual unregulated revenues were $13.3 million and the forecast for 2009 is for an increase to $16.8 million. The increase in 2009 is largely related to an increase of $2.3 million related to Generation Studies and to an increase of $1.4 million from unregulated miscellaneous revenue. This latter category is related to revenues from work related to other Hydro One entities, as well as two other sources of revenue.

25. **As described on pages 12 & 13 of Exhibit E1, Tab 1, Schedule 2, the $1.7 million forecast as unregulated miscellaneous revenues for 2010 and 2011 includes $1.0 million for forecasted work related to Hydro One Remotes Inc., $0.5 million for work related to other Hydro One entities and $0.2 million for other third party work. However, in response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 11), it was indicated that the $0.2 million was the recovery of administrative related costs from other Hydro One entities.**

26. **During cross examination, Mr. Malowzewski indicated that the interrogatory response was correct and that the original evidence was in error (Tr. Vol. 7, pgs 12-15). The $0.2 million was not associated with revenues from third parties, but was, in fact, related to the recovery of administrative costs from other Hydro One entities. Mr. Malowzewski further indicated there were external revenues from other parties outside of Hydro One included in the category.**

27. **As shown on page 12 of Exhibit E1, Tab 1, Schedule 2, Unregulated Miscellaneous Revenues are comprised of under-density billing, Inergi royalties, and unregulated miscellaneous revenues. This latter category includes $1.7 million recovered from Hydro One entities. As shown on Table 2 of the same exhibit, the total forecast for unregulated miscellaneous revenues is $1.7 million. This would appear to imply that there is, in fact, no revenues forecast related to under-density billing and Inergi royalties included in the total unregulated miscellaneous revenues.**

28. **Energy Probe submits that the Board should direct Hydro One increase the unregulated miscellaneous revenues by an amount equivalent to the expected revenues from under-density billing and from the Inergi royalties. Energy Probe does not believe that these figures are currently on the record as no revenue projections were provided on page 12 of Exhibit E1, Tab 1, Schedule 2 for either source.**

OPERATIONS, MAINTENANCE and ADMINISTATION COSTS

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Tax Harmonization

29. Hydro One has not attempted to quantify the impact of the elimination of the provincial retail sales tax (PST) and the corresponding harmonization with the goods and services tax (GST) that will result in a harmonized sale tax (HST) effective July 1, 2010. As indicated in a response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 12), Hydro One does not track the PST in relation to expenditures. Hydro One indicated, however, that a process would be developed to estimate the savings in OM&A after July 1, 2010 that result from the PST/GST harmonization and that such savings would be reflected in Deferral Account 1592.

30. The provincial sales tax is currently a portion of the expenses incurred by Hydro One as part of its OM&A expenses. When the provincial sales tax is eliminated and replaced with the HST, these costs will become an input tax credit to Hydro One that can be used to reduce the HST paid to the government based on the amount collected and paid. The net result will be a reduction in OM&A expenses to Hydro One. In the absence of any estimates from Hydro One on the magnitude of this reduction, Energy Probe submits that the Board should direct Hydro One to track this reduction using the methodology outlined by Mr. Villett (Tr. Vol. 7, pgs 15-16).

Sustaining OM&A Costs

31. Exhibit C2-2-2 sets out overall OM&A expenses for the years 2006 through 2011. Compared to 2009 expenditures, total OM&A is forecast to increase by 12% in 2010 and by 15% in 2011. Sustaining OM&A is forecast to increase by 7.4% in 2010 and 14.9% in 2011 over 2009 levels.

Distribution Lines Maintenance

32. The lines maintenance component of the sustaining increases is the most significant accounting for 45% of the increase in 2010 and 41% in 2011. A large part of these increases is due to PCB testing of distribution transformers and other oil filled line equipment to comply with federal regulation.

33. Energy Probe notes that management of PCB contaminated oils has been an issue for distributors for over 20 years since the substance was identified as a persistent carcinogenic toxin. Many distributors dealt with their PCB contaminated equipment promptly in the 1990s and are now free of the material. The fact that the Applicant apparently did not take action earlier has put it in the position of having to accomplish its PCB testing and removal under more urgent conditions and this will, in Energy Probe's opinion, likely add to the costs of the remediation program. However, the applicant is obliged to comply with regulation and Energy Probe accepts the need for and the amount of the estimated costs in the test years.

34. The other components of line maintenance are all within reasonable variances of historical costs and should, in Energy Probe's submission, be accepted by the Board.

Stations OM&A

35. The stations category comprises 39% of the increase in sustaining OM&A in 2010 and 21% in 2011. The increase is attributed primarily to PCB testing which is, like line equipment above, required by regulation. Energy Probe accepts that this increased spending is justified.

Metering OM&A

36. The increases in metering OM&A are attributed primarily to smart meter operating and maintenance costs. These new costs are $6.7 M in 2010 and $6.9 M in 2011. Energy Probe accepts that these costs are necessary and prudent.

37. Increased costs in the Customer Retail Meters category are attributable to the need to start reverification testing on smart meters installed in 2006 according to Measurement Canada requirements. Energy Probe accepts the applicant's evidence on the need for this work and its cost.

Forestry OM&A

38. Forestry OM&A cost has been increasing significantly over the past five years. The reasons for this increase have been well canvassed in interrogatories and cross examination. Energy Probe is satisfied that the applicant has supported its plans and expenditures adequately for this category of costs.

Development OM&A

39. Development OM&A is increasing significantly in the test years from $14.5 M in 2009 to $21.7 M in 2010 and $21.9 M in 2011 as shown on page 1 of Exhibit C2-2-1. Exhibit C1-2-3 comprises a discussion of the reasons for these increases which includes numerous references to the need to prepare for renewable generation connections and to smart grid development.

40. Energy Probe has reservations about the amount of renewable generation that will actually be connected to the applicant's system in the test years and this is discussed later in these submissions. Development OM&A, as Energy Probe understands the evidence, is concerned with doing the appropriate studies and developing the appropriate engineering standards to be able make generation connections and to implement smart grid technology. Therefore, Energy Probe accepts the evidence that this work needs to be done irrespective of how much and how soon those system modifications are actually needed.

Operations OM&A

41. Operations OM&A is also increasing significantly from $12.6 M in 2009 to $16.7 M in 2010 and $17.6 M in 2011. The explanations offered for these increased costs are, in Energy Probe's submission, vague and unpersuasive. For example, the summary on page 8 of the schedule states:

> *"The figures for 2010 and 2011 are greater than amounts in historic years as a result increased focus on Distribution elements in alignment with distributed generation, smart meter, and smart grid influences."*

42. This is not a satisfactory explanation for increases that amount to 33% in 2010 and 40% in 2011.

43. Energy Probe cross examined the Applicant's witnesses on the subject of operator costs. The exchange appears in the Transcript Vol 5 pages 70 line 28 to page 72 line 12 and culminated in undertaking J5.1 to provide the number of staff employed in control room and operating support functions. This was to give some context to the plan of the applicant to add 20 staff to these functions over the test years as revealed in the response to Energy Probe IR #71 (Exhibit H3-71).

44. Undertaking J5.1 responded that there are 255 regular staff employed at the Ontario Grid Control Centre with an additional 21 co-op and temporary staff. Adding 20 new staff, then, amounts to increasing staff by 8%. Clearly, this does not correspond well with proposed expenditure increases of 40% over the test years.

45. Assuming that most of the budget for these areas is labour (confirmed by the witness at lines 14-16 on page 71 of the Transcript Vol. 5) the information provided in undertaking J5.1 permits an average salary to be calculated. In 2009 the total operations expenditure shown on Exhibit C2-2-1 is $12.6 M. Dividing this by the 255 regular staff results in an average salary of about $49,000 per annum. Given that there must be building and equipment costs in the $12.6 M the resulting salary is likely less than $49,000.

46. Energy Probe finds this result unlikely given the wage levels reported by the Applicant at Exhibit C2-3-1 which shows Journeymen Line Maintainers earning a base of about $80,000. In Energy Probe's experience, control room operators and operations support staff are usually paid at least as high as line maintainers.

47. Looked at another way, if the additional $5 M proposed for 2011 over 2009 expenditures was primarily for the 20 new hires then the average cost per employee hired would be almost $250,000 per year. This result is as unlikely as the $49,000 per year result.

48. Because the information provided in the undertaking and the prefiled evidence does not make sense, Energy Probe is unable to draw any conclusions about the proposed increases other than to note that they appear to be mostly related to renewable generation and smart grid initiatives. To the extent that renewable generation connection estimates by the applicant are overstated, the need for at least some of the new hires in operations is questionable.

Customer Care OM&A

49. Customer care OM&A is forecast to remain relatively flat over the bridge and test periods. Energy Probe is satisfied that these expenditures are reasonable.

Shared Services and Other Costs

50. The large increase in expenditures in this category are in Common Asset Management Costs which are increasing from $49.1 M in 2009 to $68.3 M in 2010 and $72.5 M in 2011.

51. Energy Probe did not examine this area of expenditure in detail but notes that the commentary in Exhibit C1-2-8 page 4 lines 4-13 appears to attribute the majority of increases to demands related to the Green Energy Act. To the extent

that the applicant's estimates of renewable generation connections is overstated, the increased expenditures in Common Asset Management may also be overestimated.

Renewable Generation Connections

52. In various places in these submissions, reference is made to the applicant's estimates of renewable generation connections to its distribution system over the test years. These estimates are important because they underpin large increases in both OM&A and Capital spending proposed by the applicant. The applicant's Green Energy Plan at Exhibit A-14-2 summarizes the costs in the test years for renewable generation. OM&A costs are forecast at $3 M in both test years while capital costs are forecast at $137 M in 2010 and $265 M in 2011.

53. Energy Probe's position is that the applicant has overestimated the amount of renewable generation it is likely to see on its distribution system over the test period. This has led it to propose expenditure increases in almost every part of its application to respond to the perceived demand for connections. Energy Probe submits that expenditures related to the Green Energy Act are overstated and premature for the following reasons.

Renewable Generation Contracts are Overestimated

54. The Green Energy Plan predicts that the company will connect 3500 MW of renewable generation by the end of 2011 and an additional 3500 MW by the end of 2014 (Green Energy Plan page 13 lines 19-21).

55. In response to Undertaking J1.6 the applicant had the OPA summarize the FIT contracts to date that would affect its distribution service territory. Page 2 sets out the applications by year and shows a potential connection of 75 MW in 2010 and 11683 MW in 2011. Some of this generation was previously in the RESOP application program and once this is accounted for the actual FIT potential was 65 MW in 2010 and 1556 MW in 2011.

56. Energy Probe recognizes that these totals represent the early response to the FIT program and are only current to about mid December 2009. Undoubtedly, more applications will come forward that affect the Applicant's service territory in the coming months. The question that needs to be answered is how much will be connected in the test years.

57. Energy Probe submits that the RESOP program may provide some guidance on the subject. During the years 2006 to 2009 the Applicant processed 1553 applications for connection impact assessments. Of these, 42% were "outside the threshold for processing because of technical limitations" (Green Energy Plan page 7 lines 11-13). Of the remaining requests 869 impact assessments were completed which resulted in 127 connection cost recovery agreements being completed.

58. According to the Applicant's witness, only 20 of these projects with a total capacity of 94 MW was actually connected to the system (Transcript Vol. 1 page 112 lines 10-14). The applicant qualifies this number by pointing out that some of the unconnected projects were expected to migrate to the FIT program to take advantage of better terms. These have been captured in the OPA's material in undertaking J1.6 as amounting to 184 MW.

59. The total capacity assessed by the Applicant in the RESOP program was 12000 MW (Exhibit A-14-2 page 7 line 11). Of that total, 94 MW was actually connected and another 184 MW may yet be connected under the FIT program for a potential total of 278 MW. This represents only about 2.3% of the original capacity proposed.

60. Furthermore, even with the better FIT terms, only 184 MW or 1.5% of the original capacity proposed in RESOP has, so far, decided to take advantage of the new program.

61. Energy Probe recognizes that some part, perhaps a large part, of the original 12000 MW in RESOP could be associated with the 42% of applications that failed on technical limits. However, even if 50% of the capacity was excluded for that reason, the actual connection rate of generators applying under RESOP would still be less than 5%.

62. Energy Probe submits that the RESOP experience is useful for the Board to assess the likelihood of FIT program applications actually maturing into connections, particularly in the test years. Energy Probe's opinion is that, given the RESOP experience, even the OPA's expectations of connected generation by the end of 2011 are optimistic. Nonetheless, the OPA estimate of 1634 MW is much more realistic than the applicant's 3500 MW.

Timing of Connections

63. In order to get from the application stage to the connection stage, generators must follow a process set out in the Distribution System Code. The time to get through the process apparently varies but according to the Applicant's witness it could take up to about 8 months (Transcript Vol 1 page 107 line 26 to page 108 line 10) to get a connection cost recovery agreement completed.

64. Once a cost recovery agreement is signed, the generation project must then get built. In response to cross examination on how long that period was under RESOP, the Applicant provided undertaking J1.4. The average time from the completion of a connection cost recovery agreement to project in service under RESOP was 330 days ie. Approximately 11 months.

65. Energy Probe submits that, given these time constraints, the likelihood that 3500 MW of renewable generation will be connected to the Applicant's distribution system in 2011 is remote.

66. Energy Probe notes that the OPA forecast of 65 MW connecting in 2010 is negligible and should not require the kind of capital spending the Applicant proposes in that test year. In fact, the Applicant's evidence is that it has already connected 94 MW under the RESOP program so it should be capable of connecting 65 MW without any increase in staff or equipment. If total capital spending of $168 M in 2010 and $296 M in 2011, as shown in Exhibit A-14-2, is the requirement to connect the 3500 MW predicted then Energy Probe calculates that capital of about $132 K is required on average to connect one MW and $8.5 M should be enough to connect 65 MW.

67. Therefore, Energy Probe submits that the Board should approve no more than $10 M in capital for renewable generation in 2010. Similarly, if the OPA estimate of about 1500 MW of renewable generation could be connected in 2011, the capital requirements to do so at $132 K per MW would amount to about $200 M.

68. Energy Probe notes that the Board, in its EB-2009-0397 proceeding concerning LDC Green Energy Plans, proposes to approve only the first year plan expenditures for inclusion in rates in any distributor rates application.

69. Energy Probe supports this proposal and submits that the Board should apply a similar policy in the present application. In that case, 2011 costs for renewable generation should be collected in a variance account and the debate about whose forecasts are correct is moot.

70. Energy Probe submits that the same logic should prevail for smart grid investments. Smart grid is primarily directed to accommodating generation on distribution systems. The Applicant has forecast capital requirements of $30 M in 2010 and $62 M for smart grid investments in 2011 in its Green Energy Plan. If these expenditures are to accommodate 3500 MW of renewable generation then the

cost per MW would be about $26 K. This would translate into $1.7 M to connect the OPA forecasted 65 MW in 2010 and $39 M to connect the 1500 MW forecast for 2011.

71. As in the renewable generation case, Energy Probe recommends that the Board approve only the expenditures in the first year of the distributor's Green Energy Plan. Therefore, Energy Probe submits that the Board should approve no more than $2 M for smart grid capital investments in 2010 and nothing for 2011. Smart grid investments in 2011 should be collected in a variance account for later disposition.

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Management Compensation Plan

72. Hydro One is forecasting an increase of 3% in both 2010 and 2011 for Management Compensation Plan (MCP) staff. Energy Probe submits that the increases for the MCP should be set at 0% for both 2010 and 2011.

73. The historical and forecasted increases for the MCP have been in excess of inflation, as measured by the Consumer Price Index (CPI) for several years. The following table shows the CPI and the MCP increase in 2006 through 2008, along with the forecasts for 2009, 2010 and 2011.

Year	2006	2007	2008	2009	2010	2011	Compound
CPI - %	1.8	1.5	2.3	0.9	1.7	2.0	10.6
MCP - %	3.4	3.3	3.8	1.5	0.0	0.0	12.5

74. The information in the above table is sourced as follows. The CPI for 2006 through 2011 is from the response to Energy Probe Interrogatory # 1 (Exhibit H, Tab 3, Schedule 1) and reflects an updated Global Insight forecast from June, 2009. The compound increase in the CPI over this period is 10.6%. The MCP increases for 2006 through 2009 are taken from another Energy Probe interrogatory response (Exhibit H, Tab 3, Schedule 6). With no further increase for 2010 or 2011, the compound increase in the MCP over the 2006 through 2011 period is 12.5%, nearly 18% more than the increase in the CPI. Over the 2006 to 2009 period, the MCP increase was 12.5% as compared to an increase in the CPI of only 6.7%. It should be noted that based on Hydro One's original CPI forecast (Global Insight, December, 2008) shown in Table 2 of Exhibit A, Tab 14, Schedule 3, the compound increase in the CPI over the 2006 through 2011 period is even lower, at 10.3%.

75. Energy Probe submits that increases in excess of inflation may be appropriate when the economy is growing strongly in order to attract and keep qualified personnel. However, during economic slowdowns and recessions increases should be moderated. With no increase for the MCP in 2010 and 2011, the overall increases received by MCP members between 2006 and 2011 will be still be nearly 18% higher than the increase in inflation. Energy Probe submits that it is not unreasonable for the MCP members to effectively have a rate freeze for 2 years following increases that averaged 3.0% in 2006 through 2009, while inflation over this period averaged only 1.6%.

76. The applicant points to the need to attract and retain staff in the MCP category as a reason to provide increases above the CPI. (transcript vol. 6 page 166 lines 20-27). Under cross examination the applicant's witness estimated the turnover of MCP employees at 5% in 2008 while the overall turnover in the corporation at 3.5% (transcript vol. 6 page 168 lines 1-10). Energy Probe submits that these attrition rates are not unusually high and do not require salary increases above the CPI to address.

77. In the response provided to Energy Probe in Exhibit H, Tab 3, Schedule 6, Hydro One indicated that it could not determine the impact on the 2010 or 2011 revenue requirement of an increase in the MCP of 2.5% as compared to the 3.0% used in the evidence. However, Hydro One did some "number crunching" since that interrogatory was filed and has provided an estimate of $225,000 as the reduction in the revenue requirement by reducing the MCP increase from 3.0% to 2.5% (Tr. Vol. 6, pgs 162-163).

78. Based on this figure, Energy Probe submits that the Board should order a reduction of $1.350 million to reflect a decrease in the MCP increase from 3.0% to 0.0% in 2010. In 2011, in addition to the $1.350 million reduction, there would a reduction of 3.0% on the $1.350 million decrease for 2010, or an additional $40,000, for a total reduction in the 2011 revenue requirement of $1.390 million.

Union Compensation

79. In EB-2008-0272 Hydro One provided studies comparing its compensation and productivity levels to a peer group. The main conclusion of the Mercer study on compensation was that, on a total weighted average basis, Hydro One employees were compensated 17% above the median of the peer group. This general average was elaborated on by the applicant's witness in the present application.

80. Among employee groups, MCP staff compensation was slightly below median, Society represented staff compensation was slightly above median and PWU represented staff compensation was 21% above median (Transcript vol. 6 page 167 lines 6-14). The applicant's witness also confirmed that this wage differential still exists (Transcript vol.6 p.162 lines 4-9).

81. The Board, in its Decision in EB-2008-0272, reduced the applicant's revenue requirement by $4 M citing the following reasoning:

> "*The Board concludes that it is appropriate to disallow some compensation costs because these costs are substantially above those of other comparable companies and the company has failed to demonstrate that productivity levels offset this situation*" (EB-2008-0272 Decision with Reasons dated May 28, 2009 page 30)

82. The Decision went on to say:

> "The Board directs Hydro One to continue its key performance indicator development and to improve on its cost allocation accounting processes with the objective of being able to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs." *(Supra page 31)*

83. In response to this direction the Applicant has filed evidence in Exhibit C Tab 3 Schedule 1 that purports to justify its higher than median wages.

84. The first section of evidence is a tabulation of collective agreement provisions appearing on pages 5 and 6 of the schedule. According to Table 1 tabulating PWU agreements, the only wage concessions that the Applicant has been able to negotiate are the lowering of summer student rates to $12 per hour and the introduction of a General Helper hiring hall classification in 2001-2002; the introduction of a lower paid Meter Reader B classification in 2003-2004; and the elimination of annual incentive pay for PWU represented employees in 2005-2008.

85. Energy Probe submits that none of these provisions has made any significant progress in moving PWU represented employee compensation towards the peer group median. It is particularly noteworthy that in the most recent negotiations for 2008-2011 when the Applicant was aware of the Board's concern about compensation levels, that no progress at all was made in aligning compensation with the median of its peer group.

86. The second section of evidence directed towards rationalizing compensation levels appears at pages 13-16 of the schedule. Here the Applicant restricts its comparison to three other organizations that also have Society and PWU represented staff. The conclusion of the comparison is that the Applicant has been able to negotiate better terms with its unions than three other organizations.

87. Energy Probe submits that narrowing the comparison of compensation to just those organizations that have higher wages is not a valid justification for wages and benefits that exceed the peer group median particularly by the 21% that the Applicant's wages exceed that mark.

88. The third block of evidence that could potentially address the gap between peer group median compensation and the Applicant's compensation levels relates to productivity and appears at Exhibit A Tab 16 Schedule 1. Although considerable discussion is devoted to the subject of cost efficiencies, little of any substance emerges to support higher than median compensation levels. The general discussion culminates in Table 1 on page 5 which lists the "*Total Incremental Cost Savings – Distribution*" said to result from efficiency initiatives. No explanation is provided for the derivation of the cost savings in this table and no correlation to higher than median wage levels is drawn.

89. Energy Probe concludes that the Applicant has presented no evidence "*...to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs*" as directed in the EB-2008-0272 decision.

90. Therefore, Energy Probe submits that it is appropriate for the Board to continue the same sort of reduction in the applicant's revenue requirement as it did in the previous application to account for overcompensation of its employees.

<u>Computing the Revenue Reduction</u>

91. In the Transmission rates case, the Board decided that a reduction of $4 M in revenue requirement was an appropriate amount based on calculations provided by the Applicant in response to undertaking J3.5 (this undertaking is provided in appendix A of these submissions for the Board's reference).

92. The appropriate reduction for distribution OM&A in the present application can be estimated if it is assumed that the compensation component of distribution OM&A is comparable to the compensation component in transmission OM&A.

93. In the transmission case, 15% of total compensation was allocated to transmission OM&A. Total compensation in that application for 2010 was forecast at $619.9 M (undertaking J3.5 supra page 3) so that a total of $93 M in compensation costs was embedded in the 2010 transmission OM&A forecast of $449.6 M (Board decision page 16). The compensation component of 2010 transmission OM&A is then about 20% ($93 M / $449.6 M).

94. Distribution OM&A in the present application for 2010 is forecast at $591. Applying the same compensation component percentage as for transmission OM&A results in a total of $118 M of compensation costs being embedded in distribution OM&A. (20%x$591 M).

95. The comparable reduction in distribution revenue requirement to account for the higher than median wages paid by the applicant can be estimated by pro rating the distribution compensation component against the transmission compensation component and extending by the $13 M that the applicant arrived at in undertaking J3.5 Doing so results in a comparable reduction of $16.5 M (118/93 x $13 M).

Other Considerations in the calculation of Revenue Reduction

96. The calculations in undertaking J3.5 that arrived at the $13 M in revenue reduction contained some assumptions that are worth noting:

- The analysis excluded overtime.
- Only the OM&A impact on revenue requirement was considered

Overtime

97. The applicant's logic in excluding overtime from the analysis is that it was not part of the Mercer study. Although the amount of overtime or the rates paid were not compared in the Mercer study, overtime costs are directly related to base wage rates. If those base rates are higher than median, it is probable that overtime rates are also above median. This is a result of the formulaic calculation of overtime rates which usually involves multiplying the base rate by some factor to arrive at the overtime rate. In Hydro One's case, the first four hours of overtime after a regular shift are paid at 1.5x base rate and all hours thereafter and weekend hours are paid at 2x base. (Transcript Vol. 5 Page 65 lines 21-26).

98. Energy Probe submits that there is no basis for excluding overtime costs from the calculation of reduced revenue requirement. There are two reasons for including overtime:

- First, because overtime is paid at a premium rate, the effect on costs of paying higher than median compensation is compounded in overtime hours. If customers deserve some relief from the high compensation paid by Hydro One on regular payroll costs, surely they should receive relief when those costs are magnified by overtime premiums.

- **Second, overtime is a significant component of the applicant's compensation costs. Table 3 on page 9 of Exhibit C1 Tab 3 Schedule 2 shows overtime for 2010 years at $87.6 M which represents about 10% of total compensation. In 2011 overtime is forecasted to be $93.5 M which is also about 10% of total compensation. These costs are material and, if included in the recalculation of revenue requirement that would result form median compensation, would make a material difference in the outcome of that calculation.**

99. The amount of the recalculated revenue requirement formed a consideration in the Board's decision to reduce revenue requirement by $4 M in the transmission rates application. Had the recalculated requirement been a reduction of $20 M rather than $13 M, the Board might have arrived at a figure higher than the $4 M reduction in its decision.

100. Therefore, Energy Probe submits that any recalculated revenue requirement that the Board might consider in this application should be inclusive of overtime costs. Increasing the previously calculated $16.5 M in revenue reduction from OM&A compensation by 10% to $18 M is suggested as reasonable in light of the evidence noted above that overtime is about 10% of total 2010 compensation.

Exclusion of Capitalized labour costs

101. The Applicant's analysis in undertaking J3.5 concluded that compensation at the median level would have resulted in a reduction in compensation costs of $81.6 M. Of this, it then attributed 16% or $13.1 M to its transmission revenue requirement on the basis that 16% was the allocated amount of compensation costs for transmission OM&A. Energy Probe concludes that the balance of $68.5 M in reduced compensation must then be attributable to other causes such as OM&A from Distribution and wages embedded in capitalized costs for Transmission and Distribution that show up as depreciation and amortization expense.

102. Energy Probe submits that these categories of cost should also be considered in the issue of employee overcompensation, because they have a significant labour component and would have been less costly for ratepayers had the applicant been paying compensation at the median level of the Mercer report.

103. Capitalized compensation costs show up as depreciation and amortization expense. This is shown on page 1 of Exhibit C2 –1-1 as $259.2 M in 2010 and $291.0 M in 2011. Energy Probe recognizes that these numbers include other categories of costs besides labour compensation. But, because Hydro One does not break down its costs into labour, material and equipment and further does not separate its forecast labour costs between Transmission and Distribution, it is not clear how much labour cost is embedded in the depreciation and amortization expenses.

104. However, it is possible to estimate the compensation component in depreciation and amortization expense from the component of compensation included in capital programs proposed by the applicant.

105. Calculations above estimated the compensation component of distribution OM&A at 20% for 2010. This combined with the compensation component in transmission OM&A of 15% results in 35% of compensation being accounted for by OM&A. The balance of 65% must be attributable to Capital.

106. The capital expenditure forecast in the Transmission application was $1074.1 M (decision page 34) and the distribution capital forecast for 2010 in the present application is $565 M making a total capital expenditure forecast of $1639.1 M.

107. Total combined wages for Transmission and Distribution shown on Table 3 of Exhibit C1-3-2 page 9 are $849.5 M for 2010. If 65% is attributable to capital then $552 M of the total capital of $1639.1 M is compensation. (65% x $849.5 M).

108. This translates into about a 33% compensation component for capital work. Energy Probe submits that this would be a reasonable figure to factor the depreciation and amortization expense referred to above to determine the embedded compensation costs. Doing so results in $85.5 M in labour costs embedded in the 2010 depreciation and amortization costs. (33% x $259.2 M).

109. Using the 17% premium above median wage rates identified in the Mercer report, Energy Probe calculates that, had the applicant paid median wages, the labour component of the depreciation and amortization expense would have been $73 M rather than $85 M. ($85.5 / 1.17) a difference of $12 M.

110. Energy Probe submits that this $12 M should also be considered along with OM&A and overtime components of compensation in any revenue reduction calculation considered by the Board to account for compensation above the median of the Mercer report. Combined with the previously calculated reduction of $18 M for OM&A and overtime compensation, the total revenue requirement reduction for consideration would then be $30 M.

Staffing Levels

111. The Applicant's staffing forecasts are provided in response to Board Staff IR #71 (Exhibit H-1-71). Over the period 2008 to 2011, regular staff is forecast to increase from 4714 to 6053 and increase of 28%. When temporary staff is taken into account the total increase is from 6547 to 10245 or 56%. These proposed increases are alarming based in large part as they are on assumptions about the work required to respond to the Green Energy Act.

112. When compared to the staff forecasts provided in the transmission rates application just a year prior, the company's thinking about the work required for the Green Energy Act is evident. Page 25 of the Board's decision in EB-2008-0272 showed total staff increasing to 7072 in 2010.

113. The 2010 forecast in the present application for total staff is 9552 is an increase of almost 2500 people.

114. This level of staff buildup is, in Energy Probe's view, almost impossible to achieve in the given time frame even if it could be proven necessary. Energy Probe submits that the company's forecast of staffing requirements is well in excess of what it can reasonably achieve and also well in excess of what it is likely to need to respond to new work programs.

115. The Applicant has pointed out the significant potential for retirements during the test period as one reason for recruitment. This number is said to be about 1400 eligible for retirement by 2011 (Exhibit C1-3-1 page 1 lines 19-22). However, under cross examination the applicant's witness confirmed that actual retirement rates have been about 10% of those eligible annually (Transcript Vol 7 page 12 lines 14-25). This would translate into about 140 people needed to replace retiring workers, so recruitment to replace retirees is not a large factor in the total number of new hires proposed.

116. In the absence of other major challenges driving staff increases and, notwithstanding the need to replace a lot of wood poles and do a lot of PCB testing, Energy Probe is drawn to the conclusion that much of the expected work program expansion is related to Green Energy Act initiatives. This is the most significant driver, in Energy Probe's submission, for such dramatic increases in staff over the test period.

117. Energy Probe has argued elsewhere in these submissions that the amount of renewable generation anticipated by the applicant is not realistic during the test years and, therefore, does not require a large expansion of staff in response. It is also prudent to remember that renewable generation connections will inevitably peak and decline over a relatively short period of years. Staff that is taken on in the next few years to deal with the expected rush will ultimately have to be let go when the rush is over and that can end up being a very costly exercise.

118. Energy Probe submits that the Board should direct the company to find contractors who are able to deal with the peaks in its work program rather than hire temporary and regular staff that can become entrenched and difficult to eliminate when the work disappears. Energy Probe also notes that there are many indirect costs associated with expanding staff that would not apply with contractors. Things such as more facility space, work stations, computer terminals, transport and work equipment, small tools, safety equipment and clothing all add a large burden to the direct payroll costs of temporary and regular staff. These can be largely avoided by hiring consultants and contractors to perform work.

Issue 3.6 Is Hydro One's depreciation expense appropriate?

119. Based on the responses to interrogatories at Exhibit H, Tab 3, Schedule 14 and Exhibit H, Tab 7, Schedule 71, Energy Probe submits that Hydro One's depreciation expense is appropriate. The depreciation rates used by Hydro One are unchanged from those used in EB-2007-0681. Hydro One also confirmed that it has included depreciation expense attributable to conventional meters in both 2010 and 2011 that was used in EB-2005-0378.

120. Should the Board adjust any capital expenditures in 2010 or 2011, then Energy Probe submits that the depreciation expense should be recalculated to reflect these changes.

Issue 3.7 Are the amounts proposed for capital and property taxes appropriate?

121. Energy Probe has reviewed the forecasts for capital and property taxes and submits that they appear to be appropriate. However, should the Board adjust any of the components of the net taxable component shown in Exhibit C2, Tab 4, Schedule 1 such as gross plant at cost of the working capital allowance, then those changes should be reflected in the calculation of the 2010 capital tax. Since the capital tax is eliminated effective July 1, 2010, there would be no impact of any changes on the 2011 figure of $0.

Issue 3.8 Is the amount proposed for income taxes, including the methodology, appropriate?

122. Energy Probe submits that the methodology used to calculate income taxes is appropriate, with the correction to the capital cost allowance (CCA) that had been acknowledged by Hydro One.

123. Hydro One had incorrectly calculated the CCA for Class 12 (computer software). Hydro One had calculated the CCA associated with Class 12 as if the half year rule did not apply. This essentially accelerated the CCA deduction in 2009 and resulted in lower CCA for each of 2010 and 2011.

124. In response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 18), Hydro One acknowledge this error and provided corrected calculations. As shown in part (b) of the response the revised CCA in 2010 was increased by $22.5 million and for 2011 the increase in the CCA is $22.8 million. The impact on the revenue requirement of this correction is provided in part (c) of the response. The revenue requirement decreases by $10.2 million in 2009 and by $9.0 million in 2011. Hydro One indicated in part (a) of the response that it will reflect this corrected information in their final rate order. Energy Probe submits that the corrected

evidence is now correct and should be reflected in the calculation of income taxes, as shown by Hydro One.

125. Subject to the above and subject to any changes in taxable income as a result of the Board's Decision, Energy Probe accepts the income tax forecast for 2010 and 2011.

CAPITAL EXPENDITURES and RATE BASE

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Tax Harmonization

126. Similar to the impact of the harmonized sales tax on OM&A costs, Hydro One has indicated that it cannot quantify the impact on the reduction in the costs related to capital expenditures (Exhibit H, Tab 3, Schedule 21). As is the case for OM&A expenditures, Energy Probe submits that the Board should direct Hydro One to track the savings in capital expenditures using the methodology outlined by Mr. Villet (Tr. Vol. 7, pgs 15-16).

Allowance for Funds Used During Construction

127. As indicated in the submissions related to Issue 1.2, Energy Probe believes it is appropriate for the economic and interest assumptions to be used in determining the revenue requirement to be updated and consistent with the information used for other purposes, such as the cost of capital.

128. Hydro One has updated its return on equity and short term deemed rates to reflect the Board's recent finding in the EB-2009-0084 Report of the Board issued on December 11, 2009 (Exhibits J4.4 & J4.6). This shows a return on equity of

9.75% and a deemed short term interest rate of 1.934%. Both of these figures are based on September, 2009 information.

129. Energy Probe submits that the Board should direct Hydro One to use September, 2009 information to update its forecast of the rates used to calculate the allowance for funds used during construction.

130. For construction work in progress (CWIP) Hydro One capitalizes interest at an All Corporate Mid-Term Average Weighted Bond Yield as per the methodology approved by the Board in its letter dated November 28, 2007 in proceeding EB-2006-0117 (Exhibit A, Tab 14, Schedule 3, page 5). Based on the April 2009 spread between the average actual 10-year Government of Canada bond yield and the average DEX Mid Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com Hydro One forecast the CWIP rate to be 6.10% for 2009, 6.40% for 2010 and 7.70% for 2011. These figures are shown in Table 6 of Exhibit A, Tab 4, Schedule 13.

131. In response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 3), Hydro One updated Table 6 to reflect September, 2009 information. Hydro One maintained the same methodology as in the original evidence. The September, 2009 information reveals that the 10 year Government of Canada rates has increased for 2009 and 2010 from that used by Hydro One, while the 2011 forecast remains unchanged. This increase is 60 basis points for 2009, 80 basis points for 2010 and 0 basis points for 2011. However, the All Corporate Mid-Term Bond Spread has fallen substantially from April, 2009 to September, 2009. It has fallen from 330 basis points to 133 basis points. The overall net result is a reduction in the CWIP rate from 6.10% to 4.93% in 2009, from 6.40% to 5.23% in 2010 and from 7.70% to 5.73% in 2011.

132. As part of the response provided in Exhibit H, Tab 3, Schedule 3, Hydro One has indicated that the reduction in rate base would be approximately $2.2 million in 2010 and $6.9 million in 2011 as a result of the lower CWIP interest rates. Energy Probe submits that it is appropriate to reflect these lower rates as they reflect the same period of information (September, 2009) as used by the Board and adopted by Hydro One for the return on equity and deemed short term debt rate calculations.

Issue 4.5 Are the inputs used to determine the Working Capital component of the rate base appropriate and is the methodology used consistent with the methodologies approved by the Board in previous Hydro One applications?

133. Energy Probe submits that there are three adjustments that should be made to the calculation of the working capital component of rate base. The first two of the adjustments relate to the calculation of the cost of power. The third is related to the reduction in the overall retail revenue lag associated with the movement of 140,000 customer to monthly billing from bimonthly billing.

Cost of Power

134. The largest component of the working capital allowance is the cost of power and the commodity cost is the largest component within the cost of power. The commodity cost of power is $1,543.8 in 2010 and $1,533.2 in 2011 (Exhibit H, Tab 3, Schedule 23).

135. Hydro One has calculated a weighted average commodity price for both RPP and non-RPP customers. The rate used by Hydro One was $61.70/MWh and was based on the April 15, 2009 Regulated Price Plan Report. As shown in the response to part (d) of Exhibit H, Tab 3, Schedule 23, for Hydro One this weighted average price was based on the RPP price of $60.72/MWh and a non-RPP price of

$63.88/MWh. This non-RPP price was the forecasted HOEP price of $49.62/MWh plus the forecasted Global Adjustment of $14.26/MWh from the April 15, 2009 Regulated Price Report. The weighting used was 31% for non-RPP customers and 69% for RPP customers.

136. Energy Probe submits that the methodology employed by Hydro One is appropriate and should be approved by the Board. It reflects the mix of RPP and non-RPP volumes to provide a better estimate of the commodity cost of power. Since the commodity cost of power represents more than 50% of the total working capital allowance included in rate base, it is essential to have a good estimate of the cost.

137. Hydro One provided an updated weighted average commodity cost in response to Exhibit J7.1 that reduced the weighted average commodity cost from $61.70/MWh to $61.12/MWh. This change reflects the updated RPP and non-RPP costs resulting from the October 15, 2009 Regulated Price Plan Price Report. In response to Exhibit J7.2, this weighted average commodity cost was further reduced to $60.99/MWh if the expected change in the RPP/non-RPP mix is taken into account.

138. Use of the of weighted average commodity cost of $60.99/MWh, which reflects both the most recent Price Report and the expected mix of RPP and non-RPP volumes in 2010 and 2011 results in a reduction in the cost of power expense of $17.7 million in 2010 and $17.6 million in 2011. The corresponding reduction in the working capital allowance included in rate base is $1.9 million in both 2010 and 2011. Hydro One provided these estimates in part (e) of the response provided in Exhibit J7.2.

139. However, Hydro One has indicated that it does not support updating the commodity cost of power to reflect the most recent information available. On behalf of Hydro One, Mr. Rogers indicated that in accordance with past practice the original calculation should stand (Tr. Vol. 8, pgs 50-51).

140. Energy Probe submits that it is appropriate to update the commodity cost of power to reflect the October RPP Price Report. This will likely be the latest RPP Price Report available when the Board issues its Decision. The past practice of the Board can be ascertained in virtually any of the 2009 rate rebasing Decisions. As an example, in the EB-2008-0235 Decision and Order dated August 21, 2009 for London Hydro, the Board stated that it "concludes that the most accurate data should be used in the calculation of working capital, and notes that all parties agree with this approach." (page 33). At page 34 of the Decision it is further stated that "The Board directs London to update the cost of power to reflect the price contained in the April 2009 RPP price report, $0.06072/kWh." This was the latest RPP Price Report available at the time of the Board's Decision and Order.

141. Energy Probe also submits that it is also appropriate to update the mix of volumes to reflect the forecast of 65% non-RPP and 35% RPP volumes as forecast by Hydro One in Exhibit J7.2.

<u>Retail Revenue Lag</u>

142. Hydro One plans to migrate approximately 140,000 customers from bimonthly to monthly billing (Exhibit H, Tab 1, Schedule 58). As indicated in the undertaking response provided at Exhibit J8.5, this migration will reduce the retail revenue lag for those customers.

143. Hydro One has provided an estimate of the reduction in the overall retail revenue lag as 1.69 days from 69.99 days to 68.30 days when the migration is complete. The estimated impact when the migration is complete is a reduction in the working capital allowance of approximately $13 million.

144. Hydro One, however, submits that the reduction should only be factored in post 2011 and would be considered at the time of the next rate application. This is based on a timeline that has the 140,000 customers migrating to monthly billing beginning in 2010 and being completed by mid-2011.

145. Energy Probe submits that based on the Hydro One timeline for the migration provided in Exhibit J8.5, a portion of the full year impact of $13 million when the migration is completed should be applied to 2010 and 2011. Energy Probe submits that the following analysis should be used to determine what portion of the $13 million should be removed from the working capital allowance component of rate base in 2010 and 2011.

146. If it is assumed that the migration of customers occurs equally from the beginning of 2010 to the middle of 2011, then approximately two-thirds of the customers will have migrated to monthly billing at the end of 2010. On average for 2010 one-third of the customers would have migrated. Therefore one-third of the $13 million annual impact (or $4.333 million) should be used to reduce the working capital allowance for 2010.

147. For 2011, two-thirds of the customers could be assumed to have migrated by the beginning of the year and all to have migrated by the middle of 2011. This results in an average of five-sixths for the first half of 2011. All customers would have migrated for the second half of 2011. As a result the overall average for 2011 is eleven-twelfths (0.5 x 5/6 + 0.5 x 1). Based on the annual reduction of $13 million,

this results in a reduction to the 2011 working capital allowance component of rate base of $11.9 million.

148. Energy Probe submits that the reduction in rate base of $4.333 million in 2010 and $11.9 million in 2011 is reasonable given the evidence on the impact of the migration of the customers from bimonthly to monthly billing.

CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 5.1 Is the proposed Capital Structure and Rate of Return on Equity for Hydro One's distribution business appropriate?

149. The EB-2009-0084 Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 indicates that result of the Report is Board policy and that the process was not a hearing process that did not, and indeed could not, set rates. The Report goes on to state that the refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Specifically, the Report states:

> *"Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy)."* (page 13)

150. Energy Probe submits that based on the December, 2009 Report of the Board and the evidence on the record in this proceeding there are two adjustments that Board should make to the cost of capital for Hydro One. The first of these adjustments relates to the deemed capital structure and the second relates to the allowed return on equity.

Capital Structure

151. Short-term debt was not factored into electricity distribution and transmission rate-setting prior to 2008. As part of the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, the Board adopted a deemed short-term debt component of 4% of the capital structure. As part of that Board Report, the Board stated:

> *"As a general principle for ratemaking purposes, the Board believes that the term of the debt should be assumed to be similar to the life of the assets that are to be acquired with that debt. This suggests that, in theory, for an industry with long-lived assets, the majority of debt should be long-term. However, in reality, some short-term debt is a suitable tool to help meet fluctuations in working capital levels."* (page 10)

152. As noted in the December, 2009 Report of the Board, capital structure was not a primary focus of the consultation. The Board determined that the split of 60% debt and 40% equity is appropriate for all electricity distributors (page 50). The Board did not explicitly state that the 60% debt component of the capital structure should remain at 56% long term debt and 4% short term debt, although Table 2 provided in the Summary section of the Board Report reflects the continuation of these figures.

153. Energy Probe submits that the evidence in this proceeding indicates that the 4% deemed level of short-term debt is not reasonable and that the incremental costs imposed on ratepayers by this are neither just nor reasonable.

154. Energy Probe agrees with the Board's comments provided in the December, 2006 Report of the Board that the term of the debt should mirror the life of the assets that the debt is used to finance. By its very nature, equity is long-term financing. This leaves the mix of long-term and short-term debt to be used to provide an appropriate balance within the capital structure to reflect the actual mix of assets being financed.

155. As noted by the Board in the December, 2006 Report, short-term debt is a suitable tool to help meet the fluctuations in working capital levels. As shown in Exhibit D1, Tab 1, Schedule 4, Table 1, the net lags used to calculate the working capital allowance range from 17.12 days to 53.48 days. This reflects the short-term nature of the working capital.

156. As illustrated in Table 1 of Exhibit D1, Tab 1, Schedule 1, the cash working capital component of rate base in 2010 is $304.7 million and $309.3 million in 2011. These figures represent 6.3% of total rate base in 2010 and 6.0% of rate base in 2011.

157. At the same time, using the 4% deemed shot-term debt component to finance total rate base, the deemed amount of short-term debt is only $193.6 million in 2010 and $205.8 million in 2011 (Exhibit B2, Tab 1, Schedule 1, page 2). The shortfall in deemed short-term debt in 2010 as compared to the working capital level is $111.1 million and the corresponding shortfall in 2011 is $103.5 million.

158. Energy Probe submits that this mismatch between the level of deemed short-term debt and the working capital level included in rate base is not appropriate. The distributor is effectively financing short term assets in both 2010 and 2011 through long-term debt. This means that ratepayers are being asked to pay long-term interest rates on short-term assets.

159. The impact on the revenue requirement of this unjustified mismatch can be calculated based on the response undertakings filed in Exhibit J4.6. In particular, the following table utilizes the long-term debt rates of 5.673% for 2010 and 5.676% for 2011 and the short-term debt rates of 1.934% and 3.990% for 2010 and 2011 shown in response to Exhibit J4.6. Energy Probe notes that the 3.990% for 2011 is

only a placeholder at this time and will be replaced at the appropriate time when the Board provides the rates to be used for 2011 in late 2010.

	2010	2011
Long-term Debt Rate	5.673%	5.676%
Short-term Debt Rate	1.934%	3.990%
Difference	3.739%	1.686%
Deemed Shortfall	$111.1	$103.5
Interest Cost Impact	$4.2	$1.7

160. As the above table illustrates, the impact on the revenue requirement is more than $4 million in 2010 and nearly $2 million in 2011 assuming short-term interest rates double in the next twelve months. If short-term interest rates remain at current levels, the impact is nearly $4 million in 2011 as well. Clearly these figures for 2010 and 2011 are substantial amounts to be inflicted on ratepayers.

161. As noted above, Hydro One is effectively financing a significant portion of short-term assets with long-term debt at long-term rates. Hydro One has a significantly different level of short term working capital levels in relation to rate base than a deemed short-term debt component of 4% would imply.

162. Energy Probe submits that it is neither just nor reasonable for the Board to expect ratepayers to pay long-term interest costs to finance short-term assets. This is no more appropriate that if the distributor applied a high depreciation rate associated with computer software to a long lived asset such as poles that should have a low depreciation rate. In both cases the resulting revenue requirement is artificially inflated.

163. As noted earlier, the Board, in its December, 2009 Report indicated that panels assigned to individual utility rate cases are not bound by the Board's policy where justified by specific circumstances. Energy Probe submits that the evidence

is clear. A 4% deemed short-term debt component is not appropriate when the distributor has a short-term asset component of rate base of more than 6%.

164. Finally, Energy Probe notes the Board's comments at page 52 of its December, 2009 Report:

> ***"The Board wishes to emphasize that the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors."***

165. Energy Probe submits it is time for the evolution to begin.

Return on Equity

166. The Board has determined a methodology to determine the return on equity as part of the December, 2009 Board Report. Based on this methodology and based on the September, 2009 information that Hydro One proposes to set rates effective January 1, 2010, the return on equity would be 9.75%.

167. The Board determined the 9.75% figure based on a long term Government of Canada bond yield of 4.25% and an initial equity risk premium of 550 basis points. This equity risk premium includes an implicit 50 basis point for transactional costs (page 37 of the December, 2009 Report). This is the same amount included in the equity risk premium as determined in the Boards December, 2006 Report. In that Report the Board noted that it would continue to include an implicit premium of 50 basis points for floatation and transaction costs. The Board further noted that this inclusion had been the case ever since the Board first introduced the premium in the early 1990s.

168. Flotation costs of capital are applicable in cases where a particular distributor releases some new stocks in the market or if it issues debt. These costs generally consist of charges for underwriters, commissions to be paid to brokers, legal fees and cost of administration.

169. The costs associated with debt issuances have been reflected by Hydro One in Exhibit B2, Tab 1, Schedule 2 where the Treasury OM&A costs and other financing related fees are shown in the calculation of the carrying cost associated with long-term debt. The total of these costs for 2010 are forecast to be $1.7 million in both 2009 and 2010.

170. The allowance of 50 basis points in the equity risk premium in the calculation of the return on equity is a cost that is significantly more than the $1.7 million associated with debt issues. As shown in Exhibit B2, Tab 1, Schedule, page 2, the common equity forecast for 2010 is $1,935.9 million and for 2011 the forecast is $2,057.8 million. Based on these figures, the 50 basis points for the floatation and transactional costs represent a significant amount of the revenue requirement. This cost amounts to $9.7 million in 2010 and $10.3 million in 2011. When grossed up for taxes, these figures rise to approximately $14 million in 2010 and $15 million in 2011.

171. Energy Probe submits that inclusion of the implicit 50 basis points for transactional costs is not appropriate for Hydro One. There is no evidence to support that Hydro One expects to incur any floatation or transaction costs in either of the test years. There simply is no evidence to suggest that Hydro One will incur any of these costs.

172. As noted above, the inclusion of some provision for floatation or transactional costs in the equity risk premium component of the return on equity has been long standing at the Board, and indeed, at other regulators across North America. Energy Probe submits that distributors that have such costs should be able to recover them. Energy Probe makes no comments as to whether an allowance of 50 basis points is appropriate, is too high, or is too low. In any case, that is irrelevant in the current situation.

173. The evidence in this proceeding is that the cost is $0.

174. As noted earlier in the submissions on the capital structure, the Board panel assigned to individual utility rate cases are not bound by the Board's policy where justified by specific circumstances. Energy Probe submits that the evidence is clear. The specific circumstance in this case is that there are no floatation or transaction costs associated with equity that needs to be recovered from ratepayers.

175. The Board should not, indeed cannot, allow a distributor to recover costs that the Board knows do not exist. To do so would not result in just and reasonable rates.

176. The Board would not allow a distributor to include a capital expenditure that it knew would not take place in the test year to be added to rate base. The Board would not allow a depreciation expense to be included in the revenue requirement if that depreciation expense was calculated on an asset that did not exist. The Board would not allow an OM&A expense to be included in the revenue requirement if the evidence indicated that the money would not be spent or the addition to staff was not going to take place. The Board would not allow a cost of debt of 6% if the evidence indicates that the forecasted cost of debt for the test year is 5.75%. Why would the Board allow recovery of a cost that the evidence clearly indicates does not exist?

177. Energy Probe submits that it would be grossly unfair to ratepayers to expect them to pay for equity-related costs that do not exist. Energy Probe also submits that this would be unfair to other distributors that do have floatation and transaction costs. In the case of such a distributor, it would earn 9.75% on its deemed equity and some portion of that would be related to costs that were actually incurred. If the 50 basis point allowance is appropriate and accurate, then the shareholder effectively earns an after cost return on equity of 9.25%. The shareholder of the distributor that has no such costs, however, is allowed to earn an after cost return on equity of 9.75%.

178. Energy Probe submits that the Board should not discriminate on this basis. Shareholders of all distributors should be allowed the opportunity to earn the same after cost return on equity.

Issue 5.2 Are Hydro One's proposed costs and mix for its short and long-term debt for the 2010/2011 test years appropriate?

179. Energy Probe submits that the Board should direct Hydro One to update the revenue requirement to reflect both the actual cost of long-term debt issued in 2009 and to update the forecast of long-term debt rates associated with that debt to be issued in 2010 and 2011.

<u>Actual 2009 Debt Issuances</u>

180. In response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 29), Hydro One indicated that it had issued long-term debt in 2009 with different terms and rates from that forecast for 2009. A comparison of Attachment 1 of Exhibit H, Tab 3, Schedule 29 to page 4 of Exhibit B2, Tab 1, Schedule 2 shows the following. In addition to debt already issued in 2009, Hydro One forecast two additional issues, shown on lines 29 and 30 of Exhibit B2, Tab 1, Schedule 2, page 4.

Both of these issues were for an amount of $51.3 million, a term of 10 years and a rate of 4.77%.

181. As shown in the response to the Energy Probe interrogatory, Hydro One had an actual issue of $90.0 million for 31 year term at a rate of 5.49% and was forecasting another issue of $12.6 million for a 10 year term at 4.77%, as shown at line 30 in the Attachment to the response.

182. It now appears that the actual debt issued on November 16, 2009 was at a rate of 3.13% and term of 5 years (Tr. Vol. 3, pgs 113-115). The face value of the issue was $250 million, a portion of which was allocated to Hydro One Distribution. Mr. Van Dusen indicated that the amount was considerably more than the $12.6 million reflected in the forecast contained in the response to Energy Probe at Exhibit H, Tab 3, Schedule 29. He later indicated (Tr. Vol. 3, page 117), that the amount allocated to Hydro One Distribution was approximately $63 million more than $12.6 million forecast. In particular, the issues shown at lines 29 & 30 of the Attachment to Exhibit H, Tab 3, Schedule 29 reflected a forecast of $102 million while the actual amount for those two issues was $165 million. This would mean that the 5 year 3.13% debt instrument would be in an amount of approximately $75 million.

183. The net result of the changes noted above is a reduction in the weighted average cost of debt for these two issues from 4.77% to approximately 4.42% (both figures based on coupon rate). The overall impact on the revenue requirement of the change that reflects the 2009 actual issuances is shown in the response to an undertaking at Exhibit J4.6. The net impact on the long-term debt is a reduction in the revenue requirement of $1.2 million in 2010 and $1.1 million in 2011. It should be noted that the increase in the short-term debt rate in 2010 and the projected increase for 2011 more than offset the declines related to inclusion of the 2009 actual issuance impacts.

184. Hydro One proposes that the actual 2009 issuances that result in a lower overall cost of long-term debt for 2010 and 2011 should NOT be taken into account (Tr. Vol. 4, pgs 198-199). Energy Probe submits that the actual 2009 issuances should indeed be taken into account when determining the revenue requirement for 2010 and 2011. These costs are known. The impact on the revenue requirement has been calculated. There is no justifiable reason to exclude their impact on the 2010 and 2011 revenue requirements. Energy Probe further notes that Hydro One took the same position in its last transmission rate case (EB-2008-0272). In the May 28, 2009 Decision with Reasons, the Board directed Hydro One to update the 2009 and 2010 (test years) average cost of embedded debt to reflect the cost of actual debt issued in 2008. Energy Probe submits that the Board should direct Hydro One to do the same thing in this proceeding: update the 2010 and 2011 (test years) average cost of embedded debt to reflect the cost of actual debt issued in 2009.

<u>Forecast Long-Term Debt for 2010 and 2011 Issuances</u>

185. Hydro One has provided the details associated with the six forecasted debt issues for 2010 and 2011 in Table 3 of Exhibit B1, Tab 2, Schedule 1. The determination of the interest rates found in Table 3 is found in Table 4 of the same exhibit. As noted by Hydro One on page 7 of Exhibit B1, Tab 2, Schedule 1, each rate is comprised of the forecast of Canada bond yields plus the Hydro One credit spread applicable to that term. The Hydro One evidence also explains that the forecasts are based on data from April, 2009.

186. Energy Probe submits that it is appropriate for the Board to direct Hydro One to update the 2010 and 2011 weighted average cost of debt to reflect forecast from the same timeframe as used to set the return on equity and the deemed short-term debt rate. Assuming the Board approves Hydro One's proposal to change rates effective January 1, 2010, this would mean using September forecast information. The return on equity of 9.75% used by Hydro One in the response to

an undertaking in Exhibit J4.4 and the short-term debt rate of 1.934% used in the response in Exhibit J4.6 are both based on September, 2009 information.

187. In response to an Energy Probe interrogatory (Exhibit H, Tab 3, Schedule 27), Hydro One updated Table 4 in its evidence to reflect the information available as of September, 2009. The following table provides a comparison of the forecast Hydro One yields for 5 10 and 20 year terms for issuances in 2010 and 2011 between the original evidence and the update provided in the response to the interrogatory.

2010	5-year	10-year	30-year
Updated	3.86%	4.93%	5.84%
Original	3.78%	5.07%	6.16%
Difference	0.08%	-0.14%	-0.32%

2011	5-year	10-year	30-year
Updated	4.36%	5.43%	6.34%
Original	5.08%	6.37%	7.46%
Difference	-0.72%	-0.94%	-1.12%

188. As illustrated in the above table, there are declines in the interest rate forecast the longer the term of the issue. Energy Probe has estimated the impact on the revenue requirement of updating the cost of long-term debt to reflect the figures that are consistent with the use of September, 2009 information. The net impact is a reduction in the 2010 revenue requirement of approximately $0.5 million and in the 2011 revenue requirement of approximately $2.8 million.

189. Hydro One does not propose to update the cost of long-term debt to be consistent with the financial forecasts that drive the return on equity and cost of short-term debt that they will use (Exhibits J4.4 and J4.6). Mr. Van Dusen stated that Hydro One does not update the full cost of capital, just the return on equity (and the cost of short-term debt) (Tr. Vol. 4, page 199).

190. Hydro One has consistently stated that they believe this is selective updating and therefore inappropriate. Energy Probe respectfully disagrees. Energy Probe submits that the update of long-term debt rate forecasts to a timeframe consistent with the forecasts of long-term debt rates used to calculate the return on equity is not a selective update. The update of the long-term debt rate forecasts to a timeframe consistent with the forecasts of short-term debt rates used to calculate the short-term debt rate. These are not selective updates. They are updates to ensure the consistency of forecasts used to calculate all components of the cost of capital.

191. To illustrate the importance of the consistency, a review of Table 4 in the original evidence at Exhibit B1, Tab 2, Schedule 1 with the updated version provided in Exhibit H, Tab 3, Schedule 27 is enlightening. In 2010 the Government of Canada yields for each of the 5, 10 and 30 year terms are <u>higher</u> in the update than in the original evidence. This cannot be construed as selective updating on the part of an intervenor. In 2011, the 5 year term yield is higher in the update, unchanged for the 20 year term and lower for the 30 year term.

192. A further review of the original and updated Table 4 reveals that the reason that the updated interest rates are in general lower than those in the original evidence is that the Hydro One spreads have fallen dramatically. The 5 year spread has fallen from 1.74% to 0.73%; the 10 year spread has fallen from 1.97% to 1.03%; the 30 year spread has fallen from 2.31% to 1.42%. These declines in the spreads more than offset the increase in the Canada yields, except in the case of the 5 year term issue for 2010, where the updated rate is an increase. Again, this cannot be construed as selective updating.

193. As noted in the previous paragraph, the original Hydro One spread for a 30 year issue was 2.31% and the updated September figure is 1.42%. Energy Probe notes that in Appendix B to the December, 2009 Report of the Board, it is stated that the spread in 30-year A-rated Canadian utility bonds over the 30-year

benchmark Government of Canada bond yield is 1.415%. In other words, the September update reflects the Board's Report. Energy Probe submits it would be appropriate for the Board to direct Hydro One to update its cost of long-term debt for 2010 and 2011 to reflect a utility spread that is consistent with that in the Board's cost of capital report.

DEFERRAL and VARIANCE ACCOUNTS

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

194. Energy Probe has submissions on three aspects of the proposal related to the various deferral and variance accounts. These aspects include the amount to be cleared, the timing of the clearance and the global adjustment.

<u>Amount to be Cleared</u>

195. Hydro One is proposing to rebate a total of $25.8 million to customers (Exhibit F1, Tab 1, Schedule 1, Table 2). This amount includes unaudited balances from 2009. As shown in Table 2, the audited balances up to the end of 2008, along with interest on the balances from that point forward total a rebate to customers of $39.3 million. The reduction in the rebate based on the unaudited figures is mainly attributable to change in the global adjustment account (Exhibit H, Tab 1, Schedule 115).

196. Energy Probe submits that the Board should follow the usual practice and to direct Hydro One to rebate the audited balances in the deferral and variance accounts, along with interest forecasted up to the start of the new rate year. This would increase the rebate to customers and be a further source of rate mitigation for the increases in 2010.

197. Hydro One has indicated that its proposal follows the same approach as that approved by the Board in EB-2007-0681 (Exhibit H, Tab 1, Schedule 112). However, as noted in the discussion concerning this issue between Mr. Fraser and Mr. Buonaguro (Tr. Vol. 9, pp. 162 – 166), the Board found there were "special circumstances" in that the proposed disposition that included unaudited balances led to higher refunds for customers than would normally be the case. This effectively provided some rate mitigation relief, notably to those acquired customers that were undergoing rate harmonization.

198. However, as Mr. Fraser indicated, this is not the case in the current proceeding. The proposal to clear unaudited balances does not provide rate mitigation. In fact, it has the opposite impact. Clearance of the audited balance will provide more rate mitigation than clearance of the unaudited balances. An additional $14 million would flow back to customers over a two year period based on the difference between the audited and unaudited figures.

199. Energy Probe submits that the Board should approve clearance of the audited balances as this will provide more rate mitigation to customers. However should the Board determine that clearance of the unaudited balances is appropriate, Energy Probe submits that the Board should direct Hydro to clear the balances in the accounts as of June 30, 2009 of $30.2 million (Exhibit H, Tab 3, Schedule 31). This is the most recent estimate of the account balances in the evidence for this proceeding and partially bridges the difference between the two figures shown in Table 2 of Exhibit F1, Tab 1, Schedule 1.

<u>Timing of the Clearance</u>

200. Hydro One proposes to refund the balance in the regulatory asset accounts over a two year period (Exhibit F1, Tab 2, Schedule 1).. If rates cannot be in place for January, 2010, then Hydro One proposes that the refund should coincide with

the date of the change for future distribution rates, which is expected to be January 1, 2012 (Exhibit H, Tab 3, Schedule 37). During cross examination the Hydro One witnesses clarified that this meant that the balance would be rebated to customers over the period from when the new rates were implemented to the end of 2011 (Tr. Vol. 9, page 161).

201. Energy Probe supports this approach, but believes a modification should be made to the proposal given that the rate rider is not likely to be applied retroactively to January 1, 2010. Rather than spreading the rebate out evenly over the number of months between when the rate rider would be implemented and the end of 2011 (for example, if implemented on July 1, 2010, there would be a 18 month rebate), Energy Probe submits that whatever amount approved by the Board to be rebated/recovered to/from customers should be divided equally between 2010 and 2011. Given the shorter time period that the rate rider would be in effect in 2010, this would mean a higher rebate per kWh on volumes in 2010. This would allow customers to receive one-half of the total rebate in 2010 as would have happened if the rates had been in place at the beginning of the year. Providing for the full year rebate over a period of less one year in 2010 would also help to mitigate the rate impacts in 2010.

<u>Global Adjustment</u>

202. Energy Probe submits that the global adjustment (RSVA Provincial Benefit) should be allocated to rate classes based on non-RPP volumes. Based on the response to a VECC interrogatory (Exhibit H, Tab 7, Schedule 112) it appears that Hydro One did not utilize this allocation methodology in the calculation of the rate rider. Hydro One has provided the allocation of these costs as part of Attachment 1 to the VECC interrogatory. A comparison of this schedule to the original included at Exhibit G1, Tab 5, Schedule 1, Attachment 1 reveals a significant change in the allocation of cost associated with the global adjustment to the various rate classes. Energy Probe submits that the allocation shown in Attachment 1 to the VECC

interrogatory is the correct allocation as it consistent with the Board's Direction in its July 2009 Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046).

203. In addition to the proper allocation of the global adjustment costs based on non-RPP volumes, Energy Probe submits that it is equally important to recover these amounts from the right set of customers. In particular, the global adjustment costs should only be recovered from/rebated to non-RPP customers.

204. It does not appear that Hydro One has calculated a separate rate rider for the recovery of the global adjustment related costs. Energy Probe submits that the Board should adopt a separate rate rider for recovery of the global adjustment sub-account whenever the distributor is able to apply different rate riders to different customers within a rate class, as this follows the cost causality principle. It is not known if Hydro One has this capability or what the cost would be to obtain this capability.

205. Given the large balance in this account (nearly $20 million), Energy Probe submits that the Board should direct Hydro One to apply a separate rate rider to dispose of this amount to non-RPP customers only. If Hydro One does not have the capability to this, Energy Probe submits that the Board should defer the clearance of this amount until such time as Hydro One provides information on the cost that would be incurred to be able to do this. Given the large balance in this account and the balances likely to be in this account in the future, it may be worth the cost to ensure that the balances are recovered/rebated from the appropriate customers.

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

206. Hydro One has proposed the creation/extension of five regulatory asset accounts (Exhibit F, Tab 1, Schedule 2). These accounts are related for pension cost differential, OEB cost differential, impact of change in IFRS, fixed charges for micro-generators and bill impact mitigation.

207. Energy Probe supports the proposals related to the pension cost differential and bill impact mitigation accounts. Both of these accounts are essentially extensions of accounts approved by the Board in EB-2007-0681 (Exhibit H, Tab 1, Schedules 117 & 121). Energy Probe submits that nothing has changed related to the need for these accounts and the Board should approve their extension.

208. Energy Probe supports the need for an account to record the revenues associated with fixed charges from micro-generators. As noted in the response to a Board Staff interrogatory (Exhibit H, Tab 1, Schedule 120), the 2010 and 2011 revenue forecast does not include any potential revenues collected from this new charge as it is not possible to forecast this amount at this time. The deferral account will capture any revenue generated through this new charge and any such revenue will be refunded to customers in the future. Given the unknowns that currently exist with respect to both the rate and the number of customers associated with micro-generation, Energy Probe submits that the establishment of this account should be approved by the Board.

209. Energy Probe submits that the Board should deny the request for the OEB cost differential account. As indicated in the response provided at Exhibit H, Tab 1, Schedule 118, this request is for essentially the same account that the Board denied Hydro One in the EB-2007-0681 Decision where it stated that it did not consider it reasonable to exempt Hydro One from the Board's currently policy not to authorize an OEB cost variance account to distributors. Energy Probe is not aware of any change in this policy.

210. Hydro One has indicated that there is a regulatory precedent for their OEB cost differential account as this account was approved in EB-2008-0272. Energy Probe submits that this approval is not comparable to that being requested in this proceeding. The EB-2008-0272 Decision dealt with a transmission revenue requirement, not a distribution revenue requirement. Energy Probe submits that the Board should maintain its current policy with respect to <u>distributors</u>, and deny approval for an OEB cost differential account.

211. Energy Probe also submits that the Board should deny approval for the IFRS related account requested by Hydro One. This account is not intended to capture the variance in either transition or on-going costs associated with IFRS, as indicated in Exhibit H, Tab 1, Schedule 119 (b). In particular, the response provided indicates that"

> *"The proposed variance account is not intended to record transition costs, rather, it is being proposed to record the difference between costs in the current revenue requirement and any difference in revenue requirement resulting from changes in the application of IFRS standards once they are approved."*

212. Energy Probe submits that the Board has provided distributors with clear guidelines on this issue in the July 28, 2009 EB-2008-0408 Report of the Board – Transition to International Financial Reporting Standards. In particular, Section 8.2 of the Summary of Board Policy found in Appendix 2 of the report states that the account that the Board will establish for one-time transition costs is not to include ongoing compliance costs or impacts on revenue requirement arising from changes in the timing of the recognition of expenses. Further, in Section 7.1 of the Summary of Board Policy, the Board states that:

> *"Distributors must specifically identify financial differences and any resulting revenue requirement impacts that result from the adoption of IFRS requirements in the distributor's first cost of service application after adoption."*

213. Energy Probe submits that Hydro One has provided no justification for the deviation from the Board's policy and that their request should be denied.

214. Finally, Energy Probe submits that the Board should require Hydro One to track any variance in the actual transition costs related to IFRS from that included in rates. In response to a Board Staff interrogatory (Exhibit H, Tab 1, Schedule 119), Hydro One indicates that it currently has IFRS transition-related costs included in approved rates, but it is not tracking variances between approved transition costs and actual costs of transition in the account. This would appear to be contrary to the Board's direction in the EB-2008-0408 Report of the Board. In Section 8.2 of Appendix 2 to that report the Board clearly states that:

> *"any distributor that has IFRS related costs already approved in rates must record in a variance account the variances between the previously approved costs and actual costs of transitioning to IFRS" (page 43).*

Costs

215. Energy Probe submits that it participated responsibly in this proceeding. Energy Probe requests the Board award 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

February 5, 2010

Energy Probe Research Foundation

APPENDIX A

Undertaking J3.5, filed March 5, 2009

EB-2008-0272, Hydro One Transmission proceeding

UNDERTAKING

Undertaking

TO PROVIDE THE IMPACT ON THE OVERALL REVENUE REQUIREMENT IF HYDRO ONE COMPENSATION WAS EQUIVALENT TO THE MEDIAN, OR TO PROVIDE THE EXPLANATION WHY THAT CANNOT BE DONE.

Response

As explained in Exhibit C1, Tab 3, Schedule 2, page 2, approximately 90% of Hydro One's workforce is unionized and wages and benefits are covered by the respective collective agreements which expire beyond the end of 2010, the second test year. Collective agreements are legally enforceable contracts and cannot be unilaterally changed. As such, any reductions in our Revenue Requirement to approximate market median compensation will not reduce wages and benefits but would require a reduction in work programs.

It is estimated that if Hydro One Networks compensation was equivalent to the market median, as established in the Compensation Cost Benchmarking Study by Mercer/Oliver Wyman (the Mercer Study) found in Exhibit A, Tab 16, Schedule 2, Attachment 1, the impact would be to reduce requested Transmission Revenue Requirement in the range of about $13 million in each of 2009 and 2010.

The detailed calculations to arrive at this illustrative estimation are provided in the table on the next page. The steps taken to arrive at this estimate are as follows:

- The detailed breakout of 2009 and 2010 Hydro One Networks payroll costs (the total for the integrated workforce utilized in both the Transmission and Distribution businesses) by MCP, Society, PWU and Casual staff classifications as provided in Exhibit I, Tab 1, Schedule 19 was used as the starting point. These payroll costs are consistent with those found in Exhibit C1, Tab 3, Schedule 2, page 10, Table 3.
- As the Mercer Study did not include overtime costs, these costs were excluded from the estimation of the impact of moving compensation to market median (Column C in the table).
- The market median payroll costs for each staff category was estimated (Column D in the table) using the results in the Mercer Study, page 3, table 1. This identifies MCP ("Non-Represented") staff as 0.99 of market median, Society ("Represented Engineering") staff as 1.05 of market median, and PWU ("Power Workers") as 1.21 of market median. It was assumed that Casual staff were at the same level of market median as PWU staff for total cash compensation (+16%).
- The pension and benefits costs of the adjustment of total compensation to market median was estimated using base compensation multipliers for these costs as estimated by Mercer in their Study (Column F in the table).

- The total adjustment required to move total Hydro One Networks compensation to the equivalent to the market median is estimated as the sum of the wages adjustment and the pension/benefits adjustment (Column G in the table).
- Using data provided to Rudden in their review of the Transmission Overhead Rate Capitalization Methodology, filed as Exhibit C1, Tab 5, Schedule 2 Attachment 1, it is estimated that 16% of total Networks compensation costs are attributed to the Transmission OM&A program in 2009, and 15% in 2010. These percentages were applied to estimate the impact on proposed Transmission Revenue Requirement in both years of reducing total Hydro One Networks compensation to the equivalent of the market median (Column RR in the table).

IMPACT OF MOVING TO BENCHMARKED MEDIAN COMPENSATION

($)

2009	A	B	C = A-B	D =C/(1+% from M)	E = D-C	F =E*P/B Multiplier	G = E+F	RR =G*OM&A%
Representation	TOTAL WAGES (5)	Overtime (Incl Premium)	TOTAL less Overtime (1)	Market Median (2)	Median Adj.	Pension/ Benefits (3)	TOTAL ADJ	Tx OM&A 16% (4)
PWU Reg	300,145,964	49,412,196.28	250,733,768	207,217,990	(43,515,778)	(20,073,828)	(63,589,606)	
SOCIETY Reg	101,174,860	2,394,606.36	98,780,253	94,076,432	(4,703,822)	(2,169,873)	(6,873,694)	
MCP Reg	87,181,260		87,181,260	88,061,879	880,619	387,032	1,267,651	
Total Reg	488,502,084	51,806,803	436,695,281	389,356,300	-47,338,981	-21,856,669	-69,195,650	
Total Temp (6)	2,664,343	72,578.76	2,591,764	2,346,276	-245,488	-113,284	-358,772	
CASUAL	98,033,573	10,620,618.60	87,412,954	75,355,995	(12,056,959)	0	(12,056,959)	
Total	**589,200,000**	**62,500,000**	**526,700,000**	**467,058,572**	**-59,641,428**	**-21,969,953**	**-81,611,381**	**-13,057,821**

2010

Representation	TOTAL WAGES (5)	Overtime(Incl Premium)	TOTAL less Overtime (1)	Market Median (2)	Median Adj.	Pension/ Benefits (3)	TOTAL ADJ	Tx OM&A 15% (4)
PWU Reg	313,038,398	52,033,561	261,004,837	215,706,477	(45,298,360)	(20,896,134)	(66,194,494)	
SOCIETY Reg	111,006,705	2,518,773	108,487,932	103,321,840	(5,166,092)	(2,383,118)	(7,549,210)	
MCP Reg	90,329,523	0	90,329,523	91,241,943	912,419	401,008	1,313,428	
Total Reg	514,374,626	54,552,334	459,822,293	410,270,260	-49,552,033	-22,878,243	-72,430,276	
Total Temp (6)	922,176	76,342	845,834	733,417	-112,417	-51,876	-164,294	
CASUAL	103,456,175	11,171,324	92,284,851	79,555,906	(12,728,945)	0	(12,728,945)	
Total	**619,900,000**	**65,800,000**	**554,100,000**	**490,559,583**	**-62,393,395**	**-22,930,120**	**-85,323,515**	**-12,798,527**

Notes: (1) The Mercer Compensation Benchmarking study did not include overtime costs so it has been excluded from the estimation.

(2) As per the Mercer Compensation Benchmarking study, PWU compensation is 21% above median, Society 5% above median and MCP 1% below median

(3) Mercer derived base labour multipliers to estimate the value of benefits and pension, as used in the Compensation Benchmarking Study were applied

(4) Based on Rudden study inputs, 16% in 2009 and 15% in 2010 of Total Networks compensation costs are in the Transmission OM&A work program

(5) Source of Compensation Data is I-1-19 Attachment 1. These values do not reflect the revenue requirement for compensation for this Application

(6) Average Base Pay for Temporary (Non-Regular) employees are not meaningful because the period of employment could be significantly less than 1 year.