RP-2004-0188

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

AND IN THE MATTER OF the 2006 Distribution Rate Handbook for electricity distributors, to apply to applications for orders approving or fixing just and reasonable rates for 2006.

SUBMISSIONS IN CHIEF

of the

SCHOOL ENERGY COALITION

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INTRODUCTION

1. These are the Submissions in Chief of the School Energy Coalition with respect to the issues raised by the January 10, 2005 draft of the proposed Ontario Energy Board 2006 Electricity Distribution Rate Handbook (the "Draft Handbook").

Interest of the Intervenor

2. The School Energy Coalition is a coalition established to represent the interests of all Ontario publicly-funded schools in matters relating to energy regulation, policy, and management. It is made up all of the associations representing school interests in the province of Ontario: the four associations of school boards and their trustees, and the three professional associations of school management personnel. School boards, in their 5,000 schools and administrative buildings, spend almost $290 million per year on electricity, of which about $70 million per year is distribution charges alone. As part of the prudent management of their organizations, school boards are required to keep their energy costs as low as possible, and one way they do so is through joint participation in the regulatory processes of the OEB.

General Comments on the Submissions

3. The following submissions deal primarily with the issues identified in the Draft Handbook as contested, and in most cases we propose that the Board adopt a specific Alternative, with or without modifications. In some cases we also comment on wording that is not formally contested, either to propose modifications or additions or to raise concerns about clarity or completeness. Where possible we have proposed specific wording to assist the Board.

1. INTRODUCTION TO THE 2006 HANDBOOK

1.1 Application Components

4. ***Electronic Filing Requirement.*** The Draft Handbook, in its current form, does not expressly require filing of the application electronically. It is submitted that, given the number of applications the Board and other parties will be receiving, efficiency requires that applications be filed in electronic form, and rules be established to ensure that electronic filing is as efficient as possible.

5. Therefore, we propose that the Board add the following wording as a new sub-heading under Section 1.1:

"*Electronic Filing*

The applicant will be required to file all components of the application in both hard copy and electronically. The following rules will apply to the electronic version of the filing:

(a) Each distributor in applying for rates must provide an electronic copy of all components of the application, including, for example, the 2006 EDR Model and the 2006 OEB Tax Model, any supporting schedules, and the Description of the Application.

(b) Any component of the application that is a spreadsheet must be filed electronically in live version, ie. in native format such as Excel with all formulae intact, so that relationships between numbers, and calculations, do not have to be done manually. This will include the 2006 EDR Model, the 2006 OEB Tax Model, and any Schedules that are in spreadsheet format. Applicants may also file a PDF version of any spreadsheet, but it shall be in addition to the live spreadsheet version.

(c) Any component of the application that is not a spreadsheet can be filed in Wordperfect, Word, or PDF format, but must be identical to the hard copy filed and complete in every respect.

(d) The Board will post electronic versions of all applications on the Board's Web site when received from applicants.

(e) *Applicants may make copies of their Application or any part of it available to the public and/or other interested parties via posting on their own Web site. However, applicants who do so shall still comply with sections (a) through (c) above*."

6. The School Energy Coalition notes that lack of a similar set of rules seriously limited the ability of ratepayers to review the 2005 rate applications of the distributors, as we have described in our parallel submissions on those applications that are being filed this week. The 2006 applications will be much more complex, and the inefficiencies, delays, and lack of public access that could arise without timely electronic filing could be significant.

Additional Section - Customers and Other Stakeholders

7. It has become apparent to the School Energy Coalition and other ratepayer groups, through the experience of the Regulatory Assets proceeding, and now the reaction of electricity distribution utilities in the 2005 rates process, that the participation of ratepayers and other stakeholders in the review of distributors' rates is not universally welcomed. We believe it would be appropriate for the Board to set a tone in the Handbook that creates suitable expectations on the part of the applicants in this regard, and therefore we propose that a new section be added to the Introductory Chapter dealing with stakeholder involvement. In these Submissions we will suggest wording for the three components of that section.

8. ***Consultation Prior to Filing.*** It is proposed that the new section start with a general statement of principle on pre-application consultation, along the lines of the following:

"*Notwithstanding that the Handbook prescribes rules or procedures for most aspects of setting 2006 rates, applicants have a positive responsibility, at all times before and after rates are approved, to communicate with their customers about rate changes and how they will be affected. Prior to filing a 2006 application, each applicant should consider whether, or the extent to which, the applicant should consult with ratepayers or other stakeholders on all or any aspect of the application. The applicant should particularly consider whether any aspect of the proposed rates is likely to be contentious or have severe impact on any stakeholder group, and consider whether consultation prior to filing would be appropriate to reduce either potential conflict or any negative impacts.*

Where the applicant has engaged in consultations with its ratepayers or other stakeholders prior to filing, it would assist the Board if a summary of those consultations is included in the Description of the Application."

9. ***Provision of Application and Information to Stakeholders.*** We also propose that the new section set out clearly the obligations of the applicants to co-operate with legitimate intervenors to the rate-setting process. In particular, it is we believe important that the Board authorize and direct applicants to provide copies of their application to registered intervenors. We found, in both the Regulatory Assets proceeding, and in the 2005 rate applications, that many applicants were reluctant to co-operate with intervenors – even if the intent was to make the process more efficient – without the express instructions of the Board to do so.

10. Therefore, it is proposed that the new section include words such as the following:

"*Ratepayer groups and other stakeholders may intervene in the applications of all or some of the applicants. In order to make the process more efficient, the following rules shall apply*:

(a) *Ratepayer groups and other stakeholders who intend to be involved on an overall or individual basis in all of the 2006 rate applications may provide notice to the Board of their intention to do so on or before June 1, 2005. The Board will, on or before June 10, 2005, establish and post on its Web site a list of those whose overall interventions have been accepted (the "General Intervenors"), with their contact information.*

(b) *At the same time as an applicant files its application, it shall provide an electronic copy of all parts of that application to each of the General Intervenors. This may be done by electronic transmission or by prompt delivery of a disk containing the information. The electronic filing shall be identical in content and format to the electronic filing required to be filed with the Board, as set forth in section 1.1 of the Handbook. No hard copy of the application need be provided to any of the General Intervenors, but the applicant may do so if it so chooses.*

(c) *Thereafter, the applicant shall provide to each General Intervenor by electronic transmission copies of all additional filings or official communications to the Board relating to their 2006 rate application."*

11. ***The Role of Stakeholders in the Rate Regulation Process.*** Finally, given the potential for resistance by distributors to intervenor involvement in the 2006 rates process, we propose that the Board deal with this up front in the Handbook, and establish a protocol for ensuring that neither applicants nor intervenors make participation difficult for the other.

12. To this end, we propose that the Board include in this new section words such as the following:

"*Public participation is an essential and valuable part of the Board's rate-setting process, and it is the responsibility of all parties to ensure that public participation is facilitated and its value is maximized. For example, whether intervenors are General Intervenors or are intervening only in one applicant's case, it is the responsibility of the applicant to co-operate with their participation as long as it is reasonable and does not generate material unnecessary costs to the applicant. Similarly, it is the responsibility of all intervenors to ensure that their participation does not unduly increase the financial or other costs of the rate-setting process, nor impede the ability of the Board to establish and implement just and reasonable rates.*

To ensure that, in this transition period to full cost of service regulation, public participation adds to the quality of the Board's process, the Board will appoint, by May 15, 2005, a member of staff (the "Application Co-ordinator") to act as a liaison to deal with any concerns of applicants or intervenors with respect to participation in the 2006 rate *applications process. If an applicant feels that any intervenor is imposing unreasonable burdens on the applicant or the process, or any intervenor feels that any applicant is failing to meet its responsibilities to co-operate, that person can advise the Application Co-ordinator, who will use their best efforts to assist the parties in improving their interaction. The Application Co-ordinator will have no decision-making power, but may elect to refer any concerns to the Board if they appear to be impeding the process, and are not capable of being solved through informal discussion*."

2. DESCRIPTION OF THE APPLICATION

13. No submissions.

3. TEST YEAR AND ADJUSTMENTS

3.0 Test Year and Adjustments

14. ***Disclosure of Material Events Expected in 2006.*** The issue in this section is whether, if an applicant knows that something material is going to happen in 2006, it is obligated to tell the Board. Some parties argue that the applicant should be allowed to withhold that material information from the Board. Others argue that it should not.

15. It is submitted that it should be obligated to disclose. While the Handbook does not stipulate any consequences of that disclosure, the Board at all times has a responsibility to consider whether to give effect in its decision to any material facts before it. Those who oppose this disclosure are in effect proposing that the Board establish just and reasonable rates without all the material facts.

16. In our view, there is today a general obligation on every applicant before the Board to disclose to the Board all facts in the applicant's possession that are material and are relevant to the setting of just and reasonable rates. Alternative 1 on page 16 merely recognizes that general obligation. If that obligation is now to be undermined, it is submitted that the Board will be left attempting to exercise its jurisdiction with a blindfold on.

3.1 Historical Test Year vs. Future Test Year

17. No submissions.

3.2 Test Year Adjustments

18. ***OEB Annual Dues and Similar Costs***. We are in agreement with the Tier 1 adjustment of distribution expenses for increases in OEB annual dues. However, the wording that has ended up on page 18 of the Draft Handbook and page 25 does not track that sentiment. It uses "regulatory costs", which could be interpreted to include, for example, the internal and external personnel costs associated with filing 2005 and 2006 rate applications, etc. We believe that the wording that was intended by the parties in the working groups, and is consistent with the original concept, is "OEB annual dues and other fees paid to energy regulators". This would limit this, as intended, to the charges imposed by the regulators, and would ensure that items such as Workers Compensation fees would not inadvertently be included.

19. ***Low Voltage/Wheeling Adjustments.*** The difference between Alternative 1 and 2 in this case is whether adjustments should include amounts on which the Board has not made any

decision. It is submitted that such amounts should not be included, and therefore that Alternative 2 should be adopted.

20. There are two types of costs that could be adjusted in Alternative 1 but not in Alternative 2: post-2005 Hydro One LV charges, and ad hoc wheeling charges.

21. In the case of Hydro One LV charges, we believe that the Board should establish a general rule for the flow-through of Hydro One LV charges, likely consistent with the recent Regulatory Assets decision, so that the result is clear, well-reasoned, and consistent throughout the province. It is not appropriate for that general issue to be decided in the context of 95 individual rate applications for 2006.

22. In the case of wheeling charges, this item has not been discussed or debated before the Board in this proceeding, and there is no evidence on which to reach a blanket decision that all should be recoverable in all circumstances.

23. ***New Transformer Stations.*** The issue of new transformer stations on pages 18 and 21 of the Draft Handbook is whether new transformer stations in both 2005 and 2006 can be included in rate base as a Tier 1 adjustment (Alternative 1), or just new stations in 2005 (Alternative 2).

24. There is really no issue about whether, in principle, ratepayers should be required to bear the cost in 2006 of transformer stations in-service in 2006. In a cost of service proceeding based on a forward test year, such an addition to rate base would be included, and no-one would object.

25. The difference here is that we are not using a forward test year. As a result, many other changes in the costs, rate base, and revenue that build rates are not being included – some of which would increase rates, and some of which would decrease rates. For example, a utility with high growth (such as one that is building new transformer stations in 2006) will also be able to spread some costs over greater volumes, thus tending to drive rates down. There will be many other such changes, going in both directions, that would be necessary if a fair balance of 2006 impacts is to be achieved. Just picking one and saying that it can be adjusted, without considering the others, lacks balance.

26. It is already true that the Tier 1 adjustments approved – all of which relate to 2004 or 2005 - tend to favour rate increases rather than decreases, but the working group sought as much of a balancing of interests as possible. Adding a further adjustment or adjustments for 2006 would skew that balance, and should not be permitted.

27. It is our submission that inclusion of 2006 costs that increase rates without considering 2006 events that decrease rates creates an inherent bias against ratepayers and is not appropriate.

28. ***Smart Meters Adjustments.*** Both distribution expenses and rate base have a placeholder for

Tier 1 adjustments related to smart meters. In the event that the smart meters rollout requires either capital or operating expenses in 2006, incremental to 2004, those amounts should adjust rate base and distribution expenses respectively in 2006.

29. However, there is one important exception to this. Many utilities have capital or operating expenses in 2005 and/or 2006 for smart meters in their 2005 C&DM plans. It is submitted that, since those amounts have been paid for in full by the third tranche, it is not appropriate to add them to either rate base or distribution expenses for 2006. If an applicant were to do so, it would in effect be recovering those expenses from ratepayers twice – once in 2005, and again in 2006.

30. ***C&DM Adjustments.*** The same placeholder is inserted for the impact of C&DM expenditures on distribution expenses and rate base in 2006. For the same reasons, we agree that incremental capital and operating expenses for C&DM in 2006 should be Tier 1 adjustments to rate base and distribution expenses respectively.

31. However, for the same reasons as are set forth in para. 29 above, it is submitted that capital and operating expenses in 2005 or 2006 under the 2005 C&DM plans should not be Tier 1 adjustments to rate base or distribution expenses. As with smart meters, this would amount to charging the ratepayers twice for the same costs.

32. ***2004 Bad Debts.*** The Draft Handbook, on page 22, notes a possible discrepancy between the treatment of 2004 bad debts in Chapter 3 and in Chapter 6. It is submitted that the treatment in Chapter 3 is appropriate, and Chapter 6 should be amended accordingly. Our submissions on this point are in that Chapter.

33. ***Tier 2 Adjustments – Catchup Amounts.*** Alternative 1 on page 23 allows a utility in financial difficulty (with a clear definition) to seek an additional rate increase to bring its normal day to day spending up to a level that it believes is necessary to run the utility safely, reliably, and efficiently on an ongoing basis. It contains tight controls over who can get such an adjustment, and how much the adjustment should be, in effect amounting to a truncated version of a forward test year application. Alternative 2 on page 23 provides that, in addition to bringing spending up to the correct ongoing level, a rate rider can be added to deal with system degradation or deficiencies that arose because of limited resources in prior years. This would not relate to the financial shortfalls in prior years, but instead to the cost of bringing the system up to par. These two Alternatives both appear as well on Schedule 3-3, which is the form for Tier 2 adjustments.

34. Schools are in a difficult position on this issue. As major customers of the utilities, it is in our interests to ensure that any system deficiencies are corrected promptly, and to pay our share of the cost to do so. On the other hand, allowing a catchup could in some cases amount to funding past failures of utility management to keep their system up to a proper standard. Further, any catchup payment amounts to retroactive ratemaking, and so on principle should

be avoided if possible.

35. In our view, the choice between Alterative 1 and Alternative 2 is not black and white, and for utilities in financial difficulty it is not appropriate for the Board to establish a one-size-fits-all type of rule. Therefore, we propose that the Board adopt Alternative 2, but with the following additional caveats with respect to the part of the adjustment that relates to catchup costs:

(a) The applicant should be required to file a detailed budget of what catchup activities will be undertaken, why, when, and at what cost, and justify that budget.

(b) The catchup budget should be funded first by reducing the shareholder's return on equity. Once the shareholder's return has reached zero, the remainder of the budget can be included as a rate rider.

(c) The plan must include an analysis of the impact on rates, and if proposed distribution rates in 2006 (calculated on a standard customer impact basis using the Board's typical customers in each class) are more than 15% higher than 2005, the plan must include a proposal to spread the catchup costs over more than one rate year.

36. While adoption of Alternative 2, even with these caveats, could result in significant adjustments for some applicants, and therefore significant rate increases, it is submitted that the goals of system safety, reliability and efficiency cannot be compromised. With the protections we have proposed in place, we believe that this category of adjustments will only arise where the need is clear, and therefore the work should actually be done.

37. ***Schedule 3-2.*** This Schedule, on page 27 of the Draft Handbook, is for Tier 1 "Non-routine/unusual" adjustments. On this form, the applicant looks at distribution expenses and rate base in 2004, and identifies any material items in 2004 that are not normal annual items, and are not expected to recur in 2006. There is a similar adjustment for revenue on page 87.

38. Our concern is that, while the utility is required to report on this form the details and impacts of those non-routine and unusual occurrences in 2004 that the applicant has determined in its judgment should be adjusted, the reporting of other such occurrences that the applicant believes should not be adjusted is less complete. In paragraph 4 of the form, those excluded items must be identified, but no dollar amounts or other impacts are required. It is submitted that the applicant should be required to provide the same information for a non-routine/unusual item that it decides should not be adjusted as for those for which it seeks an adjustment, together with the explanation of why some items are excluded. This way, the Board will better be able to assess whether the adjustments achieve the appropriate balance.

4. RATE BASE

4.1 Definition of Rate Base

39. ***Level of Detail in Filing.*** The School Energy Coalition supports the level of detail set forth in Alternative 1, and in the 2006 EDR Model and Appendix B, all as defined by the working group in this area. It is submitted that, for this transition year, this finds an appropriate balance between sufficient information to review prudence, and keeping the regulatory burden on the applicants within reasonable bounds.

40. ***Effective Date for Rate Base Calculation Purposes.*** Neither Alternative 1 or Alternative 2 is correct in principle, because in both cases they are based on 2004 data, as are all calculations in a historical year model. If a utility's rate base is growing, Alternative 1 will be a closer proxy to 2006. If a utility's rate base is falling, Alternative 2 will be closer. No rule that applies to all utilities will create the correct proxy for rate base.

41. However, because the rate base number is within the context of an application that is historical in all respects, there is another approach that can identify the fair result. Since volumes (of kwhr., KW, and customers) are also based on 2004 (actually, an average of 2004 and prior years), but are being used as a proxy for 2006, calculating rate base in parallel with the treatment of volumes will tend to cause any errors in using historical test year to balance each other out.

42. In this instance, the volumes for 2004 that are being used to establish rates in 2006 are those volumes derived from the rate base as it increased or decreased during the year. If rate base was growing, volumes were probably also growing through the year, and the volumes for 2004 will reflect the average rate base during 2004. Similarly, if rate base was falling, volumes were probably also falling through the year, and the volumes for the year will still reflect the average.

43. Therefore, it is submitted that Alternative 2, which calculates rate base in the same way as the proxy for the volumes (revenues) it was generating, produces the best result, consistent with the other aspects of the 2006 EDR Model.

44. ***Inclusions in 2004 Net Fixed Assets.*** On page 31 of the Draft Handbook, there is a list of fixed assets that are included in the rate base for 2006. It is submitted that this list may give the wrong impression to some applicants, and therefore some clarification would be useful.

45. In particular, we note that the list implies that some items, like capital expenditures for C&DM or smart meters, will be included in 2004 net fixed assets as adjusted. This presupposes the results of the placeholders for C&DM and smart meters, on which we have commented in paragraphs 28 through 31 above.

46. Therefore, we propose that the bullet relating to those items on page 31 of the Draft Handbook be deleted. This will avoid any confusion, and other parts of the manual will in any case make clear how C&DM and smart meters are dealt with for rate base purposes.

4.2 Amortization Rates

47. No submissions.

4.3 Capital Investments

48. ***4.3.1 – Reporting Requirements for Non-IT Related Capital Investments.*** The reporting requirements for IT capital related investments are already stipulated in 4.3.2. It is submitted that establishing a separate requirement for non-IT related capital expenditures is unnecessarily complex, and the appropriate course for the Board to take is Alternative 1, which adopts the same thresholds as 4.3.2.

49. We note that Enbridge and Union, which are large relative to most of the electricity distribution companies, report all individual capital expenditures in excess of $500,000, which is the same as the top level in Alternative 1 and section 4.3.2. This suggests that at the top end the reporting requirements proposed is reasonable for large electricity distributors as well. It is submitted that the dollar amounts at the other levels bear a reasonable relationship to the highest figure, and therefore are prima facie reasonable themselves.

4.4 Interest on Deferral Accounts and Construction Work In Progress (CWIP)

50. ***Interest on Deferral Accounts.*** We believe that the evidence of the Vulnerable Energy Consumers Coalition, filed as Exhibit B.1, demonstrates that for most deferral accounts the appropriate interest rate is the short term rate. It is therefore submitted that Alternative 2 is the general rule that the Board should adopt for 2006.

51. We note that the evidence shows that there may be exceptions, where a deferral account will be outstanding long enough that a medium term or other rate should be employed. While this will be rare, we believe the best way for the Board to deal with this is to order the use orf a different rate on that account when it is established (or for those that are already established, via accounting orders). This reflects the fact that these will be exceptional circumstances, and so should be dealt with individually.

52. ***Interest o*n *CWIP.*** We agree with the consensus that appears to have emerged that AFUDC is the appropriate approach for construction work in progress.

4.5 Capitalization Policy

53. ***Filing of Capitalization Policy.*** The method used by the applicant to determine when and to what extent operating expenses are to be capitalized can have a significant impact on rates, both for the current year and for future years. The issue in this section is whether the Board and ratepayers are entitled to disclosure of the utility's capitalization policy, if there is a formal policy in place. Since there is no issue of secrecy, or confidentility to protect a competitive advantage, possible here, the only legitimate consideration could be the administrative burden on the utility of including this in the application. It is submitted that filing the policy, if there is one, is likely to reduce the burden by making the narrative in the Description of the Application shorter. Further, for any utility that has gone to the trouble of having a written capitalization policy (likely the larger and more sophisticated distributors), the administrative burden of attaching it to the application is likely to be trivial.

54. We also note that the Board is expecting to look at policies relating to capital expenditures in 2007 or 2008. Filing by the utilities of their capitalization policies will provide an open and transparent starting point for dealing with this issue at that time.

4.6 Contributed Capital

55. No submissions.

4.7 Treatment of Capital Gains and Losses

56. No submissions.

5. COST OF CAPITAL

5.0 Introduction

57. ***Removal of Unnecessary Narrative.*** It is submitted that this Chapter, including the Introduction, contains some explanations that are not necessary and should be removed. This is especially true since, with a few exceptions, the capital rules will be built right into the 2006 EDR Model, so no active steps will be required by the utility to calculate these items.

5.1 Maximum Return on Equity

58. **Removal of Unnecessary Narrative.** We believe that this section should simply say: "*The maximum allowed return on equity is 9.61%. A utility may elect a return on equity less than the maximum allowed. The utility should state the return on equity it is seeking, if less than the maximum, in the Description of the Application*."

59. ***Updating of ROE Calculation.*** The disputed issue in this section is whether ROE should be updated late in 2005, and a variance account established to track the difference between the amount collected in rates and the revised ROE. It is submitted that this is unnecessarily complex and is not appropriate. Further, if there is an increase in ROE, the result is that ratepayers in 2007 or later are retroactively charged for the ROE in 2006. This retroactivity should be avoided unless there is a clear need for such an update. No such need has been demonstrated by any party to this process.

5.2 Debt Rate

60. ***Weighted Average Debt Rate.*** Page 41 of the Draft Handbook (and the related Schedule 5-1) has two choices for calculating the weighted average debt rate. The difference is the deemed rate to be used for debt held by affiliates. In Alternative 1, the affiliate debt is deemed to be at the lesser of the actual interest rate, or the deemed rate for 2006. In Alternative 2, the affiliate debt is deemed to be at the lesser of the actual interest rate, or the deemed rate at the time the debt was originally issued.

61. The purpose of have a deemed rate for affiliate debt at all is that the shareholder has a conflict of interest. On the one hand, it wishes to maximize the interest it receives on its debt. On the other hand, through its control of the utility board it has an obligation to keep the cost of capital as low as possible. The deemed rate ensures that the shareholder does not favour its desire to maximize the interest it receives.

62. The problem with moving back to the date the debt was issued is that it re-engages that

conflict of interest by incenting the shareholder to game the rule. When the shareholder lends to the utility, it establishes as the interest rate the deemed rate. The next year, if the deemed rate has gone up, it cancels the old debt and lends instead at the new, higher rate. On the other hand, if the deemed rate has gone down, the old debt is retained, as it allows the shareholder to receive an above-market interest rate.

63. As a result, over time the interest recovered from ratepayers will never be less than the market rate, and often will be more because of the gaming that is available.

64. We note that, in a different context, this type of gaming is quite commonplace. For example, the Income Tax Act provides that certain debt has favourable tax treatment if it is set at the market rate at the time it is originally incurred. That tax treatment is better if the interest is lower. Therefore, it is normal practice to terminate and re-lend the debt whenever the market interest rate drops, so that the lowest possible rate is always locked in. Although the situation of the utilities here favours the opposite strategy (locking in the highest possible rate), the concept is identical.

5.3 Capital Structure

65. No submissions.

5.4 Working Capital Allowance

66. ***Adjustment of Commodity Cost.*** Increasing the working capital allowance to reflect anticipated higher commodity costs in 2006 is but another example of adjustments that increase rates being favoured but adjustments that decrease rates being ignored. Since 2004 historical is the proxy for the rate year 2006, it is submitted that the working capital allowance should be based on the 2004 data consistently. Therefore, Alternative 1 should be adopted by the Board.

67. ***Customer Security Deposits.*** Page 44 raises the question of whether customer security deposits are an appropriate offset from the working capital allowance. Some distributors have tens of millions of dollars of customer deposits on hand.

68. It is submitted that this is about the need for working capital. To the extent that the distributor has cash on hand from customer security deposits, it does not need that amount for working capital. Therefore, it is submitted that Additional Adjustment Alternative 1 on page 44 should be adopted.

6. DISTRIBUTION EXPENSES

6.0 Introduction

69. ***Level of Account Detail.*** Page 47 of the Draft Handbook raises the question of the level of detail applicants should report distribution expenses. Alternative 1 is the full trial balance of the utility (ie. all of the USofA accounts), while Alternative 2 groups them into categories.

70. It is submitted that in 2006 the overriding imperative of giving the Board and the parties detailed information should be tempered with a recognition that the utilities are in a transition from very limited (by government restrictions) regulation to a cost of service model, at least for a couple of years. In this case, and subject to the requirements of the Comparators and Cohorts process, we believe that the grouped information we have seen in draft form will be sufficient for the 2006 rate-setting process.

71. We do suggest one additional provision, though. If the Board adopts the grouped approach, we are concerned that the result may simply be additional interrogatories of some applicants, increasing rather than decreasing the regulatory burden for them. Therefore, to "head that off at the pass", we propose that the Board add the following in the "Level of Account Detail" section of this Chapter:

"*While the grouping of distribution expenses is the basic filing requirement, applicants should review each of the grouped totals to identify any that are unusual in their size, or in their pattern from year to year. Where either of those factors exist, the applicant should file a breakdown of that total by USofA account, together with an explanation of any unusual amounts or variances*."

6.1 Definition of Distribution Expenses

72. ***6.1.3 - C&DM Placeholder.*** We have made general submissions on C&DM in new Chapter 16.

6.2 Detailed Reporting for Specific Distribution Expenses

73. ***6.2.1 – Insurance Expense – Self-Insurance Costs.*** The alternatives on page 49 of the Draft Handbook turn on whether a reserve for self-insurance is equivalent to a payment to a third party insurer. Alternative 1 would treat a change in reserve as if it were an insurance premium. Alternative 2 would include in self-insurance costs claims paid, but not reserves. It is submitted that Alternative 2 should be adopted by the Board.

74. Self-insurance is a common and legitimate way for large companies to deal with routine

risks. In fact, many third party insurance plans are actually self-insurance, since while premiums are paid and claims are made to the third party insurer, there is a periodic true-up that ensures that the premiums equal the claims plus an administrative charge. Further, it is common for companies in a similar business for form co-operatives to take their insurance risks. Most professional groups do this, and so do many manufacturing and commercial sectors.

75. Pure self-insurance is actually no insurance. A risk is simply accepted by the business itself, and claims are paid when received and proved. The "expense" related to that risk is the amount of claims paid out in the year. For example, while many companies have product liability insurance with commercial insurers covering things like injury and death, most companies do not have product warranty insurance to cover the performance of their products. Instead, if they have a warranty claim, they pay the cost of responding to it as a current expense.

76. The use of reserves for self-insurance is a method of smoothing the sometimes lumpy expenses associated with annual claims costs. When done prudently, the annual self-insurance reserve represents a type of average of annual claims costs for a number of years.

77. The difficulty with treating self-insurance reserves as distribution expenses in 2006 is that they are heavily driven by actuarial calculations and judgment. The first means that, if it wishes to test the expense, the Board must embark on a complex analysis that is not efficient in the context of the 2006 rate cases. The second, judgment, means that the Board can only test the expense by obtaining information on the basis for the relevant judgment calls in the analysis. This is usually done by oral evidence, which all parties are, we think, trying to minimize in 2006.

78. Therefore, we believe that the appropriate choice is to use the amounts that are known and readily identifiable, which is the claims paid in the base year. This is a non-controversial, easy to determine amount that will simplify the process and ensure that neither ratepayers nor distributors are disadvantaged.

79. ***6.2.2 – Bad Debt Expense – 2004 Recovery.*** It is submitted that paragraph 3 on page 50 of the Draft Handbook should be reworded to be consistent with page 21 in Chapter 3. The concept in Chapter 3 is that a bankruptcy or other bad debt, <u>if non-routine or unusual</u>, is a mandatory Tier 1 Adjustment. This is clear on page 21. However, in paragraph 3 on page 50 it is not as clear.

80. Therefore, it is proposed that the two sections of the Handbook be made consistent by replacing paragraph 3 with the following:

"*3. Bad debt occurrences, including bankruptcies, are a mandatory Tier 1 Adjustment if they are material and they are non-routine or unusual. If the applicant regularly experiences material bad debt occurrences each year, either of a certain type or due to a common cause* *(e.g. continued winding down of a major local industry sector), they may be routine and usual. If the applicant believes that to be the case with respect to any of its bad debt occurrences in 2004, it should explain the circumstances in detail in the Description of the Application, together with historical data and other background evidence sufficient to demonstrate the routine nature of the occurrence*."

81. ***6.2.4 – Charitable Donations.*** Unlike many ratepayer groups, Schools believe that charitable donations by utilities should be allowed within reasonable bounds. The government, the Board, and ratepayers want the distributors to act like well-managed private sector companies. But for well-managed private sector companies, we expect that part of their responsibility is to be good corporate citizens. This includes participating in community activities and causes, and contributing to worthwhile charitable activities. The Imagine Campaign, for example, is a well-known and broadly supported program under which companies contribute 2% of net profits to charities. Many of Canada's best-managed companies are participants in the Imagine Campaign.

82. Therefore, it is submitted that the Board should adopt Alternative 3 on page 52 of the Draft Handbook.

83. However, we have a concern that Alternative 3 is completely open-ended, and does not place any limited on charitable activity. In a rate-regulated environment, a spending authority without limits is inappropriate. We therefore propose that the Board add a cap on Alternative 3, and that cap should be the lesser of 1% of MARR and $500,000.

84. We note that, because this would be a change to past practice, and because 2006 will for most applicants be based on historical year data, the charitable donations actually allowed for 2006 may be quite limited. It does, though, establish the principle for future years, and free up utility management to take one more step towards acting like well-managed private sector companies.

85. ***6.2.4 – Meals/Travel and Business Entertainment Expenses – Filing Policy.*** In paragraphs 53 and 54 above we discuss the rationale for requiring the filing of the applicant's formal capitalization policy, if they have one. For the same reasons, applicants should be required to file their meals, travel and business entertainment policy if they have one.

86. ***6.2.5 – Total Compensation Filing Requirements for Small LDCs.*** It is submitted that Alternative 1, which exempts very small distributors from certain employee compensation reporting, is appropriate and should be adopted.

87. However, we wish to register a concern, discussed in more detail below, that this exemption may be applied to exempt larger but "virtual" utilities from providing the Board with compensation information. We believe that the provision of information for the Board on human resources costs should include both internal and external FTEs, so that comparisons can be made and the Board can determine on a reasonable basis whether the utility's overall

human resources costs are prudent.

88. ***6.2.5 – Disclosure of Remuneration Above $100,000.*** It is now commonplace for public sector employees, including employees of many Crown corporations, to have their remuneration published if it aggregates more than $100,000 in a year. While for the most part the figures on the annual remuneration lists surprise no-one, on occasion this transparency disloses a remuneration package that is excessive or otherwise inappropriate. Similar rules apply to senior employees of public companies in both Canada and the United States. Alternative 1 at the top of page 55 of the Draft Handbook would apply this same $100,000 disclosure rule to employees of the distributors. Alternative 2 would allow the distributors to keep their compensation of senior executives secret from the public.

89. It is submitted that the distributors, who operate public franchises, usually for public sector shareholders, and get all of their money from members of the public, the ratepayers, who have no other supplier of their service, should be held to the same level of transparency and public scrutiny as other public sector employees. Senior executives of the LDCs should not be paid so much that they would be embarrassed for the members of their community – their customers – to know how much they make. This level of transparency can only be of concern to those who are being paid unreasonable compensation, and we do not feel the Board should have a role in protecting the secrecy of their pay packet.

90. ***6.2.5 and Schedule 6.1 – Eligible Incentive Plans.*** The second set of Alternatives on page 55 of the Draft Handbook distinguishes between recoverable and non-recoverable incentive plan payments. Alternative 1 sets the recoverability test at “substantial benefit to ratepayers”. Alternative 2 sets the non-recoverability test at “immediate benefits primarily to the shareholder”. While we believe that the difference between the two is largely semantics, the clearer wording is probably Alternative 2, and therefore we ask the Board to adopt that choice.

91. The easiest way to test this is to look at how each wording would deal with common examples. The two examples in the preamble are obvious. Both Alternatives would allow recovery from ratepayers if the incentive plan is based on reducing OM&A expenses. Both Alternatives would disallow recovery from ratepayers if the incentive plan is based on increasing share value.

92. One that is perhaps somewhat more difficult is an incentive based on meeting approved MARR. This is also, by the way, one of the most common performance measures for LDC executives, and it clearly creates benefits “primarily to the shareholder”. On the other hand, it could be argued that meeting the MARR threshold is in the interests of the ratepayers too, since it ensures a financially healthy distributor. On balance, we believe that incentives for such a performance measure should come from he who gets the money, which is the shareholder, although we accept that the opposing view is arguable as well.

93. Another example that is becoming more common in companies is a performance measure based on customer satisfaction surveys. Where a company is privately owned, this type of measure clearly is for the benefit of the customers. However, where a company is owned within the public sector, it could easily be a measure designed to generate voter satisfaction rather than customer satisfaction. Despite this twist, we believe that the balance favours treating such a performance measure as for the customers rather than the shareholder.

94. While we have submitted that the Board should adopt Alternative 2 on this point, whichever choice the Board makes we would ask that the Board in its decision identify some examples such as these and explain how it views the recoverability of incentives in those borderline situations.

95. ***6.2.7 and Schedule 6.3(a) – Distribution Expenses Paid to Affiliates – Filing Requirements.*** The first set of Alternatives on page 58 of the Draft Handbook relates to whether market testing data, and affiliate cost data, should be filed where distribution expenses paid to an affiliate are based on cost-based pricing by the affiliate. Alternative 1 would require that to be filed, and Alternative 2 would not.

96. This is really a practical matter more than anything else. We have the experience of substantial affiliate transactions in the gas distributors' rate cases, and the information requests and other results those transactions generate. One of the things many ratepayer groups, and perhaps the Board, are trying to avoid is extensive interrogatories on individual applications, and disputes on the scope of the inquiry. We believe the most efficient approach in the face of 95 applications is to require the initial filing of all information that is material and relevant, and that the Board can reasonably expect will be filed at some point in the process anyway.

97. We note that this is not a case where the information is immaterial or irrelevant. It is now well accepted that, while compliance with the Affiliate Relationships Code is technically a matter that should be dealt with in a proceeding under that Code, in any rate case distribution expenses must be tested for prudence, and when they are amounts paid to affiliates the factors outlined in the Code are important aspects of that prudence review. A number of utilities have elected to move many of their operating functions out of the regulated utility and into affiliates, in some cases creating "virtual" utilities. Where functions are billed from affiliates, and the billing is on a cost basis, the only way the Board and ratepayers can test prudence is to look at those costs.

98. It is therefore submitted that affiliate cost information should be required at the outset, thus avoiding interrogatories and limiting disputes over the information to be filed.

99. ***6.2.7 – Distribution Expenses Paid to Affiliates – Compliance Information.*** A related question arises in the second set of Alternatives – should applicants have to show in their initial filing how they complied with the Affiliate Relationships Code? Alternative 1 says

they should, and Alternative 2 says they should not.

100. Some of the practical reasons set forth above apply equally here. However, the answer to this may be simpler than that. One must ask whether anything in the second paragraph of Alternative 1 is untrue? If it is true – which clearly it is – then it is only fair to tell the applicants this, and give them an opportunity to explain why they did not comply with the Code in some way. There is little doubt that a utility with material affiliate payments that are non-compliant will face tougher scrutiny of those costs, and full recovery may in some cases be in doubt. This is consistent with the Board's past practice, and with the requirement that rates be just and reasonable. Failing to advise the applicants of that fact, when the Board knows it to be true, seems to us to be prejudicial to the applicants.

101. ***6.2.7 – Distribution Expenses Paid to Affiliates – FTE Equivalency Data.*** The "virtual" utility creates another problem, human resources costs. Two utilities with the same customers, throughput, and systems, and the same number of people actually serving those customers, could have dramatically different human resources costs due to outsourcing. This creates a difficulty for comparison of costs and efficiencies between distributors.

102. We propose that the Board add, on page 59 of the Draft Handbook, the following additional section to deal with this:

"*Equivalent FTEs*

Any applicant that spends more than 10% of their distribution expenses on payments to affiliates and/or shared services shall prepare a schedule of equivalent FTEs, listing for each major functional area of the distributor's activities the FTEs employed to deliver that function, broken out into FTEs who are employees of the distributor, and FTEs who are provided through affiliates or shared services arrangements."

103. We note that, while the addition of the above wording does not lead to a complete and comparable FTE filing for all applicants in 2006, it will go one step in the direction of solving a comparability problem that has been identified by Mr. Camfield and others as an issue for the Comparators and Cohorts process, so it will have value not only in 2006, but for subsequent years as well.

7. TAXES/PILS

7.0 Rules and Principles

104. ***Proposed Removal of Explanatory Narrative.*** The Draft Handbook contains, at the beginning of Chapter 7, the note "This draft of the 2006 Handbook retains explanatory detail in Chapter 7 which may be removed in the final version." It is submitted that, while in most cases throughout the Handbook the wording should be simple and direct, and explanations of the rationale behind instructions may not be required, in the tax chapter additional explanatory information on the directions given would be useful.

105. There are two specific reasons why additional narrative is appropriate. First, it is clear that tax issues are particularly difficult for non-specialists to understand, so simple explanations of some of the instructions will assist distributors in following those instructions. For example, the explanation of the difference between "tax-driven factors" and "operations-driven factors" on pages 68 and 69 will help the distributor to understand the nature of the true-up and will help them to understand what will be going in their Taxes/PILs variance account.

106. Second, we note that, whatever the Board decides with respect to the tax issues in the Draft Handbook, it will be a significant change from the current rules. Distributors will need explanations to help them understand changes from their past practice in this complex area. Otherwise, it is simply human nature for distributor management to assume that the existing rules continue to apply, and understand the instructions in the Handbook in that context. For example, if the Board determines that CCA and ECE are to be calculated taking into account the FMV Bump (see below), this is a change that some distributors may not immediately understand unless there is a fuller explanation of the new rule.

7.1.1 General Principles Underlying the 2006 Tax Calculation

107. ***After The Fact True-Up to Actual Taxes Paid.*** Pages 68 through 70 of the Draft Handbook raise the issue of the extent to which variances in taxes or PILs from forecast to actual should be debited or credited to a variance account, to be recovered or repaid to ratepayers.

108. The Board will receive general submissions on this issue, saying, in effect "Why should the ratepayers pay either more or less in rates than the actual taxes paid?" Those submissions may come from either ratepayer representatives, or distributor representatives.

109. The Taxes Working Group was made up of more than a dozen utility and ratepayer representatives, many of them with extensive background in tax issues. Unlike many other issues, which clearly have utilities on one side and ratepayers on the other, in this case most

of the representatives from all groups realized that, on this issue, the devil is most clearly in the details. In a series of lengthy discussions in which a possible true-up was contentious, then a consensus emerged, then it was lost, and so on, the Working Group finally drilled down below the surface of the issue and identified the appropriate break point.

110. It should be noted that "no true-up" is not proposed as an option in the Draft Handbook. While the debate on this was at many times a true-up vs. no-true-up debate, in the end there is complete consensus that there should be a true-up. There is also a consensus that the true-up should cover all of the tax-driven factors that create variances between forecast and actual taxes, ie. the factors that are clearly outside of the control of utility management. The question that the parties are asking the Board to consider is: *"Should variances in actual taxes costs by operations-driven factors be trued up after the fact?"* Alternative 1 would exclude those factors, and Alternative 2 would include them.

111. Before dealing with Alternative 2, it is appropriate to consider some elements of Alternative 1 (which, of course, is a subset of and therefore necessarily included in Alternative 2). Alternative 1 lists the types of changes in the "tax rules", using that term loosely, that could cause actual taxes to be different from forecast taxes. There are three categories:

(a) Changes in the formal tax rules.

(b) Changes in the way the tax authorities interpret the rules, which changes are usually referred to as changes in assessing policy or changes in administrative policy.

(c) Changes in the "opening balances" for the distributor as a result of re-assessments of prior years.

112. In the case of each of the categories of changes set forth in Alternative 1, it is only those changes that arise after the rate application is filed that are relevant for variance account purposes. For example, it is expected that the tax rules in place or known as of the filing date will be incorporated into the OEB Tax Model. If the federal budget on February 24th increases corporate income tax rates by 1% on January 1, 2006, the 2006 OEB Tax Model will assume tax rates in 2006 that include that increase. Similarly, if the Ontario budget comes down in April, and includes a change in the regulations increasing investment tax credits in 2006, we expect that Board staff will revise the model to take that into account, and advise all applicants accordingly.

113. But what if the federal budget <u>in February 2006</u> contains that 1% increase in corporate tax rates? In those circumstances, there is a complete consensus that the additional taxes payable by a distributor as a result of that change have to be charged to a variance account, and recovered from ratepayers in subsequent years. And, conversely, if the hypothetical increase in investment tax credits above is introduced in the 2006 Ontario budget, rather than 2005, any incremental tax reduction as a result of that change would be credited to the same

variance account, to be refunded to ratepayers in subsequent years.

114. Board members and other parties asked a number of questions during the hearing with respect to the clarity of changes in assessing policy or administrative policy, the second of the two tax factors creating variances. There appear to be two questions here:

(a) How will the Board know that a change in assessing policy or administrative policy has occurred?

(b) How will the Board determine whether such a change should be treated as equivalent to a change in the formal tax rules?

115. On the first of these points, we believe that the Board will be advised of these changes directly through public information, and by the distributors or, in some cases, by ratepayers.

116. In practice, changes in assessing or administrative policy are promulgated in two ways. First, some are published in press releases, interpretation bulletins, information circulars, and public rulings by the tax authorities themselves. If Board staff do not already subscribe to one of the main tax services that provide this information (and are relied on by members of the tax community including many utility personnel), we believe that they should do so. That way, any public changes in assessing or administrative policy will be known to Board staff at the same time as they are known to the distributors.

117. Second, some changes are seen only in the individual audits or private rulings for specific taxpayers, in this case distributors. This is particularly likely with some narrow utility-specific assessing policy changes, which may not have sufficient general interest to be publicly reported. In this case, we believe that the Board should instruct distributors to bring any changes in assessing policy that come to their attention to the attention of Board staff at the time they occur. If Toronto Hydro, for example, receives audit results that, for example, disallow Class 8 CCA treatment of particular assets and require them to be in another class, Toronto Hydro should advise Board staff accordingly as this could impact all distributors.

118. It is submitted that, between the tax services and information from individual distributors, Board staff will in fact have better information on assessing policy as it affects LDCs than anyone else in the industry.

119. The second question is how the Board should determine which changes in assessing or administrative policy should be treated as general changes warranting variance account entries.

120. For most interpretation changes, in practice it will be quite clear whether the change is similar to a change in formal rules. For example, virtually all changes that are publicly announced in interpretation bulletins, information circulars, and public rulings are intended to be changes of general application. That is generally the point of making the

announcements public and formal.

121. Changes that come to the surface through audits of or rulings on individual distributors can require a little more judgment. In each case, someone has to determine whether the audit or ruling result is driven by the particular facts of the case, specific to that taxpayer, or whether the result reflects a change in the taxing authority's thinking on the subject generally. This is a non-trivial task requiring specialized knowledge and good judgment, but it is also one that a number of people on Board staff have both the qualifications and experience to do. Further, and perhaps fortunately, the number of changes of this sort that arise through audits or private rulings is quite small in any given year (ie. a handful, or less). The time commitment required of Board staff is not likely to be material, and if issues are difficult it will be possible to convene a small ad hoc group of utility and ratepayer tax specialists to help characterize the impact.

122. Therefore, it is submitted that the second category of tax-driven changes – changes in the interpretation of tax rules – is sufficiently clear and administratively manageable that it should be included in the true-up.

123. The third category is even more clear, but it is important to understand how limited it is. Where a distributor receives a re-assessment of taxes for a year prior to 2006, two things are likely to happen:

(a) First, the tax bill for that previous year is changed, and the distributor either owes more taxes to the government, or will get a refund.

(b) Second, the 2006 opening balances for certain tax accounts will be changed due to changes in credits and debits to those accounts in prior years, and those changes in opening balances will affect the calculation of 2006 taxes.

124. The changes to the prior year tax bill (item (a) above) are not part of the 2006 true-up mechanism. Under the heading "Tax re-assessments" on page 70 of the Draft Handbook, the wording makes clear that the prior year tax increases or decreases are not part of the Handbook, and will be dealt with separately through the old Account 1562. Thus, the comments of Mr. Krakowski on this point (Tr. 1-246 to 258) are a bit confusing unless read in conjunction with his later explanation (Tr. 1-333 to 343).

125. But a change to 2004 can affect 2006 as well, and it is that change that is trued up. For example, in 2004 the distributor may have claimed $1,000,000 in capital cost allowance on a particular asset, but been re-assessed on the basis that the allowed CCA was only $500,000. In that example, the undepreciated capital cost at the end of 2004 would be changed to a higher amount as a result of the re-assessment. Since CCA in subsequent years is based in part on the undepreciated capital cost at the beginning of the year, the 2004 change would increase CCA in 2005, and also in 2006 (it flows through year to year). That increase in 2006 CCA would reduce 2006 taxes, and that tax reduction is credited to the 2006 taxes

variance account, to be refunded to ratepayers.

126. As a result of this distinction between prior year impacts and 2006 impacts, the issue of truing up interest or penalties does not arise. The 2006 impacts, which are the ones that are being trued up, are current and therefore do not generate either interest or penalties.

127. Turning to operations-driven tax variances, which is the contested issue, there are two categories of these variances that can arise. As noted in the Draft Handbook, at page 69, they are:

(a) Variances driven by changes in the mix of expenditures of the utility that have different tax attributes.

(b) Variances driven by higher or lower than expected earnings.

128. We should note that, of these two factors, the first has a very small impact, in most cases almost zero. The main impact would be from changes in the overall earnings.

129. In the case of mix-driven variances, we believe that management takes these impacts into account when they make operational decisions. Take a simple example. The forecast includes $1,000,000 for capital expenditures that would be depreciated for accounting purposes at 4%, and for tax purposes at 10%. During the year, management decides to divert those funds to $1,000,000 of capital expenditures that have an accounting depreciation rate of 20%, and a tax depreciation rate of 50%. The difference between the two rates of accounting depreciation drives one tax change, but that is a change in accounting earnings. To the extent that the difference in tax depreciation rates is greater (or lesser) than the accounting difference, that would be a change in mix rather than a change in earnings. In deciding whether to divert the funds from one project to another, management in its cost-benefit analysis would normally consider all financial impacts of the change, and that small tax differential should be one of them.

130. It is submitted that truing up for amounts such as this is inappropriate for two reasons:

(a) Variances such as this are within the control of management, who should manage them the same as they manage other costs arising out of their operating decisions.

(b) The small amounts involved do not justify the administrative burden, given the often complicated calculations necessary (see above) to determine the exact impact of changes of tax mix. Further, those calculations are often likely to involve significant judgment (what part of this tax impact is because of the change in expenditure mix, and what part is because earnings changed?), leading to potential disputes over small dollar items.

131. If there is a variation in earnings, though, that can drive a large change in taxes. Higher

earnings than forecast will mean taxes will be greater, and lower earnings will mean taxes will be lower. In those circumstances, in which the shareholder is receiving more or less than the allowed rate of return, what is the appropriate treatment of the PILs?

(a) In Alternative 1, any increase in the shareholder's return above the allowed return is net of the taxes on those increased profits (ie. the net of each dollar of overearnings to the shareholder is the same as each dollar of regular earnings), and any decrease in the shareholder's return below the allowed return is also net of the taxes saved on the lower profits (ie. the cost to the shareholder is only the net earnings they would have otherwise received from the utility).

(b) In Alternative 2, any excess profits generate a higher tax that is charged to the variance account and billed to the ratepayers. Conversely, a profit shortfall means a credit to the variance account, and the shareholder in effect has to refund taxes to the ratepayers.

132. It is submitted that the result in Alternative 2 is inappropriate for four reasons:

(a) *It is "symmetrically perverse".* If the profits of the utility are higher (in effect, the utility has recovered more in rates than was needed to cover its costs and a reasonable return), the ratepayers are penalized for the shareholder's overearning by a further bill in a subsequent year for the taxes on the excess. This is, in effect, the opposite of earnings sharing. In this case, the shareholder gets a bonus for overearning, because overearnings are tax free whereas regular earnings are on an after-tax basis. Conversely, if the utility misses its profit target, it not only loses the actual profits it failed to achieve, but it also has to pay a penalty to the ratepayers of a refund of some of the rates collected. It apparently didn't collect enough to cover its costs plus a reasonable return, so it has to give some more back. ("That'll teach 'em to miss their target"?) It is submitted that this is obviously inappropriate, and an unfair penalty to the utility.

(b) *It creates a counter-productive incentive.* A distributor, faced with system in which there is a true-up of taxes driven by earnings variances, is incented to estimate revenues as low as possible. While the 2006 process has limited room to adjust revenue forecasts, there still is some judgment, and in any case the PILs rules will apply to those who file on a forward test year basis as well. All of them will want to keep their forecast revenues as low as possible, thus increasing rates initially, and increasing the problems associated with (a) above. Why does this incentive occur? Because this true up increases the reward for overearning, and increases the penalty for underearning. Utilities are already incented to underestimate volumes in order to keep unit rates high and thus increase probable profits. By making overearning a dollar worth $1.60 because it is tax free, and by making underearning a dollar cost $1.60 because of the required tax refund, the

Board would be increasing the incentive to underforecast volumes. We note that this also increases the incentive to overforecast costs and rate base, for the same reasons.

(c) *It is biased in favour of the shareholder and against the ratepayers.* Profit of the utility is to some extent within the control of management. While there are clearly external factors that drive profit up and down as well, management has some level of control, and can respond to those external factors by mitigation or investment to ensure that the shareholder's rate of return is met in the end. The clearest evidence of this is that, despite revenue caps in the past few years that have often been unfair to utilities, many utilities have still been able to meet their target rates of return. This stands to reason. Management is told by their shareholders that the target rate of return is their earnings goal for the year, and management responds to that challenge by cost and revenue actions that attempt to generate that result. In practice, this will mean that there are more likely to be overearnings – and therefore an additional bill to ratepayers – rather than underearnings, with the resulting refund. The asymmetrical nature of this earnings variation in practice will be exacerbated by the point in (b) above, ie. that overearnings are worth more than regular earnings, and underearnings attract an additional penalty.

(d) *It may create significant administrative inefficiencies*. The last two points raise an additional issue that may be of concern to the Board. Most utilities will file on a historical test year basis for 2006 in any case, and some will file on a forward test year basis regardless of the tax true up decision. There will be a few large utilities on the fence: able to afford a forward test year application, but wary of the resources required to participate in such a process. For those few large utilities, the incentive to create tax-free overearnings rather than taxable regular earnings, and the fear of a penalty for underearnings, may cause them to undertake the forward test year filing so that those impacts can be managed more effectively. In effect, the Board in choosing Alternative 2 could be inviting some utilities to game the system by filing on a forward test year basis.

133. For the above reasons, it is submitted that the Board should include in the Draft Handbook Alternative 1, and limit true-up to tax-driven factors outside the control of management.

7.1.2 Principles Applicable to Specific Components of the Calculation

134. ***Non-Recoverable and Disallowed Expenses – General Submissions.*** The Board heard evidence from two experts on whether expenses that are deductible for tax purposes, but not recoverable from ratepayers, should be included in calculating the taxes recoverable in rates. Dr. Jack Mintz, an expert in corporate tax matters with a national and international reputation, gave evidence sponsored by the School Energy Coalition. Dr. Mintz readily

admitted that he is a tax expert, not a regulatory expert, and he approached the issue from the point of view of tax and economic principles. Kathy McShane, a well-known expert in regulatory accounting who has appeared before the Board many times before, gave evidence sponsored by the Coalition of Issue Three Distributors, including most of the province's largest LDCs. Ms. McShane readily admitted that she is a regulatory expert, not a tax expert, and she approached the issue from the point of view of regulatory principles.

135. It is, of course, not possible to determine with any rigour the likely PILs component of rates in 2006, but the School Energy Coalition estimates that it will be in the range of $300 to $400 million across the province, before taking into account the reductions from non-recoverable items. Current public filings of utility information do not disclose how much their current PILs are reduced by deducting non-recoverable expenses, but it is clear from this process that the utilities believe the amount in issue is very substantial. We estimate that it could be as high as $100 million per annum.

136. But the problem, from a ratepayer point of view, is more significant than that. Amounts recovered from ratepayers to pay tax are actually grossed up, since tax is not a deductible item and so, in effect, tax must be paid on the tax recovery such that the net amount is sufficient to pay the tax on the allowed profits. If the utilities need $300 million to pay their tax bills, they have to recover $450 million or more from ratepayers, pay the tax on that additional revenue, and then have $300 million left over to pay the tax on allowed profits. That means that, if taxes could vary by as much as $100 million in 2006, depending on the result of the decision on this issue, then rates could vary by as much as $150 million as a result of the decision on this issue. While this may seem like double counting, any simple calculation of variations in underlying tax cost and its impact on rates will show that this is true. And, although the impacts are not known with precision, whatever the actual figures it seems clear that the dollar impact of this tax issue will be substantial.

137. In this section of our submissions, we propose to consider the issue on the basis of general principles. First, we will look at the reasons why the taxes collected in rates should be calculated taking these deductions into account (ie. Alternative 2 on page 72 of the Draft Handbook). Then, we will consider the evidence of Ms. McShane, and look at why the Board should not be persuaded by her contrary position. , Commencing at paragraph 187 and following of these Submissions, we will look at four specific examples of non-recoverable expenses and their tax consequences: charitable donations, interest, purchased goodwill, and the fair market value bump.

138. It is submitted that there are five main reasons why taxes collected in rates should be those actually expected to be paid, rather than a higher amount of taxes calculated by excluding the impact of non-recoverable expenses:

(a) *Follow the money.* When amounts are collected in rates for taxes but are not used to pay taxes, they end up in the hands of the shareholder, constituting a subsidy of the ratepayers of the shareholder's unregulated activities.

(b) *What costs should be recoverable from ratepayers?* If all deductions are not taken in calculating taxes for ratemaking purposes, the utility is overstating the tax expense and thus, unlike any other cost, is recovering more for that cost than it is actually incurring.

(c) *Regulation as a proxy for competitive markets.* In an unregulated competitive market, tax savings from all sources are, and have to be, passed on to customers in prices so that the company can stay competitive. The economic principles make clear that the last place tax savings would go is to the shareholder, since that would result in overcompensating the shareholder for their capital invested.

(d) *PILs is a closed system.* Every dollar of PILs collected by distributors from ratepayers and diverted to shareholders constitutes another dollar of Debt Retirement Charge that ratepayers will have to pay later on. This results in the ratepayers paying down the stranded debt twice rather than once.

(e) *Wrong incentives to the shareholders.* By allowing shareholders to use the regulated utilities that they own as a type of tax shelter, the Board would be encouraging negative behaviour by utilities, including spending utility funds on shareholder priorities in order to save tax, and selecting financially risky capital structures in order to save tax.

We propose to look at each of these five reasons in turn.

139. Perhaps the single most compelling reason to favour Alternative 2 on this issue is the implicit subsidy of non-recoverable amounts that arises if tax savings they generate are diverted to the shareholder. Dr. Mintz, in his direct evidence, gave an example to help the Board understand this impact (Tr. 1-487 et. seq.). He described what happens when the utility spends $100,000 for political donations. In short, if the shareholder spends $100,000 on political donations, it costs the shareholder $100,000. If the utility spends $100,000 on political donations, it in effect comes out of the shareholder's money in the utility, and so initially costs the shareholder $100,000. However, then it is deducted for tax purposes, saving $35,000 of tax. If that tax money was collected from the ratepayers in rates, then saving that tax means it is diverted to the benefit of the shareholder. The net cost to the shareholder of the political donation is thus reduced from $100,000 to $65,000. As Dr. Mintz put it, the $35,000 is converted from being an amount for taxes, when charged to ratepayers, to being a political donation subsidy provided by the ratepayers. The effect is that the ratepayers pay 35% of the political donation.

140. It is submitted that there is no way around this result, and no amount of throwing "regulatory principles" at it can change the dollar impact. Non-recoverable expenses paid in the utility will, if the tax savings are not used to reduced rates, constitute a subsidy by the ratepayers of

unregulated activities. This is because money is actually collected in rates for taxes, but is not used to pay taxes. Therefore, it must be used for something, and that something is to reduce the net cost of the unregulated activity.

141. The Coalition of Issue Three Distributors will argue that different activities within the corporate entity should have their profits, and taxes, calculated separately, an application of the standalone principle. We saw in cross-examination that they want to use the example of two profitable activities in the corporate entity, one of which is regulated, to show that the standalone approach is fair. They argue that just as revenue and expenses should be allocated between regulated and unregulated activities, so should taxes be allocated in the same way.

142. This argument is a red herring. Of course it is true that if there are two profitable activities in the corporate entity, one of which is the regulated distribution business, all revenues, costs, and taxes should be allocated between the two activities to produce separate profits from each source. Indeed, this result would occur whether the two activities were in the same corporate entity, or in two different corporate entities, the latter being in any case the most common corporate structure in which utilities hold multiple profitable businesses.

143. In the case of two profitable activities, utilities do not seek to use any money collected from ratepayers to fund an unregulated activity. The revenues from the unregulated business pay the costs, taxes, and profits of that business, just as if it were legally separated. None of the revenues from the ratepayers are needed for that unregulated business. It is self-sufficient.

144. The problem with this argument is not the initial paradigm of two profitable business. The problem is what happens when you try to apply it to a profitable regulated activity coupled with an unprofitable (or even non-profit) unregulated activity. Activity A is a regulated distribution business that makes a profit of $1,000,000 a year and pays $350,000 in tax on that profit. The costs of that business, plus the $350,000 of tax, plus the $650,000 of after-tax profit, all come from the distribution ratepayers. Activity B is an unregulated activity (either unprofitable or not profit-driven) that loses $1,000,000. Revenues from that activity, if any, are insufficient to cover its costs, and there is a $1,000,000 shortfall. The shareholder can redirect its $650,000 of after-tax profits from the regulated business to cover part of the shortfall. This is fair, since those funds are the shareholder's return, and it can do with it what it wishes. But this still leaves a $350,000 shortfall. The Coalition of Issue Three Distributors wants the Board to allow it to use the money collected from the ratepayers for taxes to instead pay that shortfall.

145. The difference between the two examples is striking. In the case of two profitable activities, there is no cash flowing between activities. In the case where the unregulated activity is not profitable, ratepayer funds have to flow to the unregulated activity to cover its loss. Also, in the case of two profitable activities, they can be carried out in two separate corporations, as they often are, since the cash flow and tax consequences are the same either way. In the case where the unregulated activity is not profitable, there would be no flow of tax funds from the

regulated activity to the unregulated activity if they were in two separate corporations, so they have to be in the same corporation for the subsidy to be available.

146. The second reason for Alternative 2 is based not on the practical result of what happens to the money, but on the general principle of what should be recovered from ratepayers in rates. Taxes are a cost of providing the distribution service. This is the reason why they are recoverable from ratepayers. With all other costs, the amount recovered from ratepayers is the actual amount expected to be paid. The question is fairly raised: Why should taxes be any different?

147. Now, the Coalition of Issue Three Distributors will argue that, using the standalone principle, the costs recovered from ratepayers are not the actual costs. Instead, they are a lesser amount representing the portion of the corporate entity's costs that are allocated to the regulated business. In fact, they may point out that in some cases it is exactly this allocation of only some costs to the regulated activity that means the tax results should also follow that allocation.

148. Once more, this argument is a red herring, for the same reasons as their defence of the cross-subsidization. If the corporate entity pays $1,000,000 in taxes, of which $700,000 arises as a result of the regulated activity, and $300,000 arises as a result of the unregulated activity, the customers of the regulated activity have $700,000 allocated to them, and the customers of the unregulated activity have $300,000 allocated to them. This is exactly the same as any other cost of the entity that is shared between regulated and unregulated activities.

149. But that is not what the Coalition of Issue Three Distributors is seeking. It is seeking a situation in which, for example, the corporate entity pays only $700,000 of net taxes, of which $1,000,000 "arises" as a result of the regulated activity, and ($300,000) "arises" as a result of the unregulated activity. They argue that although only $700,000 is paid in taxes, $1,000,000 should be allocated to the customers of the regulated activity, and a $300,000 credit should be allocated to the customers of the unregulated activity.

150. That seems fair on the surface, but the way to test it is to ask how it would be applied if the cost were something other than taxes. Take, for example, the IT Department. The total cost of the IT Department is only $700,000. The company argues that the portion of that cost that "arises" as a result of the regulated activities is $1,000,000, since that is what the regulated activity would have paid on its own for these IT services. Therefore, it says, the cost to the unregulated activity should be a credit of $300,000, in effect an amount that the regulated activity ratepayers should pay to the credit of the unregulated activity to pay for the savings generated by the economies of scale and synergies between the two.

151. We fully recognize that the example is ridiculous, but that is not the fault of the example. It is ridiculous because the idea that an allocation between regulated and unregulated activity within a corporate entity would produce a cost to the regulated activity and a negative cost

(ie. a credit) to the unregulated activity is completely absurd and contrary to every principle the Board has ever used to allocate common costs shared with unregulated activities.

152. In our submission, taxes should no more be allocated so that the unregulated activity has a negative cost than should any other cost of the corporate entity carrying on the utility business.

153. The third reason why Alternative 2 is the appropriate result is rooted in the basic concept of utility price regulation. Regulation of monopoly prices is intended to be a proxy for competition. In an unregulated competitive market, the tax savings in issue would necessarily go to the company's customers. The regulator should therefore follow the competitive market and allocate those tax savings to the customers as well.

154. Dr. Mintz began his discussion of this key issue by describing the concept of the "incidence" of taxes (Tr. 1-463 to 472). Simply put, when a competitive company has a change in a cost input, including taxes, it has three places it can reflect that change. First, it can raise or lower the return to its shareholders. Second, it can raise or lower the wages it pays its workers. Third, it can raise or lower prices. There is nowhere else the impact can be felt in the typical competitive company.

155. In fact, companies in a developed economy open to capital flows to and from global markets cannot raise or lower the return to shareholders. The after-tax cost of capital at a given risk level is set by the marketplace. If a company pays less than the market rate for capital, it will not attract sufficient capital, and will fail. If a company pays more than the market rate for capital, its competitors will be able to pay less and thus have a price advantage. In a competitive market, this can also be fatal. Therefore, to all intents and purposes variations in tax costs cannot be paid to or deducted from the return to the shareholders.

156. We note that this is particularly applicable in the regulatory environment, where the return to the shareholder is not just set by the market, but is set by the market and then fixed by the regulator after reviewing that market. At least on a forecast basis, the return on capital to the shareholder of a distribution company is not a variable amount.

157. In short, the last place that variations in taxes should be reflected is in the cost of capital, and therefore using the competitive model the last place that tax savings should go is to the shareholder.

158. Cost increases, including increases in taxes, can sometimes be borne by the employees, either through reduced compensation, or increased productivity. In either case, the units of production per dollar of employee cost are increased. Conversely, if costs go down, some portion of the savings can go to employees, for example as incentive bonuses. This generally happens after the fact, though, rather than in advance when setting prices. In general, companies have to compete on the labour market for the best talent. If they pay too little, they will not attract sufficient good staff, and will be uncompetitive. If they pay too much,

they will be undercut on prices by competitors who have optimized their labour costs.

159. Again, the normal impacts are exacerbated in the case of regulated entities, because under cost of service regulation labour costs are set at the lowest reasonable amount, before prices are set. While incentive bonuses might be paid if employees are able to drive down other costs during implementation, the starting point is the lowest reasonable labour costs necessary to attract sufficient quality personnel.

160. That leaves prices. In this regard, Dr. Mintz explained the economic principle as follows:

"An unregulated competitive company is under constant pressure to reduce prices, and the means to do so is, generally, a reduction of costs. For this purpose, you can treat the cost of capital as given. The capital markets will stipulate how much the company has to pay for its capital at a risk level. Management has to reduce other costs to drive prices down. If it does that successfully, its prices will be lower than its competitors and it will be able to sell its products. And, if it fails to bring down costs, and competitors are able to do so, the competitors will have lower prices and make the sales. This is the essence of competition in markets.

For this reason, all unregulated competitive companies have to minimize their taxes. When they do so, those tax savings are passed through at lower prices. If they do not minimize taxes, [or] they do so but they don't pass them in through lower prices, their competitors can do so, and that can give competitors a competitive advantage.

If regulation is to be a proxy for competition, then tax minimization should be a required goal of all regulated entities. And all tax savings should be passed on into lower rates. This is precisely what would happen in an unregulated competitive company. I do not see any principled way that a regulated entity could have as a different rule and still be consistent with its competitive counterpart." (Tr.1-496 to 500)

161. So many aspects of economics are difficult for the non-economist, but this is really just common sense. Companies compete to offer a product or service at the lowest possible price for a given quality or functionality. They do that by cutting costs, including taxes. If their competitors cut costs better than they do, the competitors will have a competitive advantage. Cutting costs doesn't count if the savings are not passed on in lower prices, since a competitor who does pass those savings on will have lower prices and a competitive advantage.

162. As regulator, it is submitted that the Board should adopt Alternative 2 on this issue, since it tracks the workings of the competitive market by passing cost savings on to the customers in prices.

163. The fourth reason that Alternative 2 is the correct one is the special nature of PILs, which is unique to Ontario and has no parallel in any other North American jurisdiction. This is straightforward enough. Every dollar paid in PILs reduces the amount that, over time, ratepayers have to pay in Debt Retirement Charge. (Which Ms. McShane admits: Tr. 5-370.) If ratepayers pay $300 million in rates to pay PILs in 2006, that is $300 million less debt to pay. The amount of the debt goes down immediately, so interest ceases to accrue on that component, and over time the Debt Retirement Charge is reduced by both the $300 million of principal and the interest costs it would otherwise have generated.

164. But that is not true if the utilities don't use that $300 million collected from ratepayers to pay PILs. If $100 million is diverted to the shareholders, instead, to subsidize unregulated activities, then the ratepayers will have paid $300 million towards the stranded debt, but the debt will have only gone down by $200 million. That additional $100 million will continue to accrue interest, and eventually the ratepayers will have to pay both the $100 million, and the accumulated interest, again even though they have paid for it once already.

165. In questions asked of Dr. Mintz, the Chairman got this balance exactly right by looking at the Alternative 2 scenario. At Tr.1-1124 to 1234, Mr. Kaiser goes back to example of the $100,000 donation. If Alternative 2 is selected, so that all of the tax savings from this deduction are credited to the ratepayer, rates go down by $35,000. However, over time the ratepayers will have to pay an additional $35,000 (plus interest) in Debt Retirement Charges to cover this part of the stranded debt. This – Alternative 2 – produces a fair balance. The ratepayers do get a saving today, but they pay for it later with interest. This is, as the Chairman pointed out, just like getting money from the bank, and then paying it back with interest over time.

166. And, as Dr. Mintz confirmed during that exchange, the opposite is also true. If Alternative 3 (all savings to shareholder) is selected, the ratepayers will be in the position where they would not have received the $35,000 in the first place, but they have to pay it back with interest over time as if they did. This would be like going to the bank and getting a $35,000, but the bank saying that you have to make the payments, but you can't actually have the initial money. Who would think it is fair if they have to repay a loan that they never actually received?

167. The fifth and final reason for choosing Alternative 2 is a practical one. Whenever the Board establishes rules for a given activity, it must identify the behaviours it is implicitly promoting or incenting, and those that are being restricted or disincented. In this case, giving the shareholder a benefit from causing the utility to spend on non-recoverable items, as either Alternative 1 or Alternative 3 would do, promotes the use of the utility as the shareholder's captive tax shelter vehicle.

168. The problem stems from the fact that most of the shareholders of the distributors are tax exempt entities. That, of course, should generally be a good thing, but there is one downside.

Typically the cost of goods or services does not change based on whether the payor is taxable or non-taxable. If it costs $10 million to build a park, it costs that same $10 million whether the payor can take a tax deduction for the cost, or not. In the result, if the shareholder of a distributor pays for a park, it actually costs that $10 million. But, if the distributor builds the park, and takes the tax deduction, the net cost after taking the tax savings into account is only $6.5 million. Unless the Board selects Alternative 2, it will be in the financial interest of the shareholder to cause the distributor to pay for anything that is deductible, at least until PILs is reduced to zero. Under Alternative 3, they can spend about three dollars inside the utility for every two dollars outside the utility (or, in the case of Alternative 1, six dollars for every five).

169. Of course, one way the Board can deal with this problem is to establish a set of rules that prohibit any spending by the regulated corporate entity except amounts that are recoverable from ratepayers. This is in fact how Ms. McShane said, in an exchange with Ms. Chaplin, she would solve this problem (Tr. 5-693 to 702). To a limited extent, this is what the Board does with gas distributors, for example, through the Undertakings which severely restrict the activities of the gas distribution companies. While some non-recoverable expenditures still take place in those companies, their scope is very limited.

170. But this, it is submitted, is an unnecessarily complicated response to the problem. The simpler approach is to ensure that there is no benefit from the inappropriate behaviour. If the shareholder doesn't get any financial benefit from washing non-recoverable expenditures through the utility, it will be less likely to do so.

171. We note that a particular example of this problem is interest deductions. As we will discuss in more detail below, unless the Board mandates Alternative 2 on this issue, the tax-exempt shareholders of the distributors will be encouraged to impose capital structures and terms on their local distributors that are not in the public interest. Everyone agrees that would not be appropriate. The way to prevent it is to take away the financial incentive favouring that behaviour.

172. Before turning to the specific examples of this issue identified separately in the Draft Handbook, it is useful to look at the evidence of Ms. McShane purporting to support Alternative 3. Ms. McShane says there are four reasons why shareholders should get the benefit of utility tax savings from non-recoverable expenses:

(a) *Benefits follow costs*. Since the shareholder's money is being used to fund the non-recoverable expenses, the shareholder should get the tax benefits associated with that spending.

(b) *The standalone principle*. It is a longstanding regulatory rule that rates should be calculated as if the regulated activity "stands alone", separate from any outside influences on its costs.

(c) *Keeping a level playing field.* The same rules should apply to LDCs that pay taxes as those that pay PILs.

(d) *No harm to ratepayers.* Regulatory rules must meet the threshold test of not generating any harm for ratepayers.

173. If the shareholder's money is used to fund the non-recoverable expenses, why shouldn't the shareholder get the tax benefits associated with that spending? The answer is that they should, of course. But Ms. McShane, not a tax specialist but a regulatory specialist, misses a key point here. The tax benefits associated with a tax exempt entity (like a municipality) spending money are zero. Tax exempt entities do not get tax benefits, because they do not pay tax. Therefore, if it truly is the <u>shareholder's</u> money being spent, there is no tax benefit to give to the shareholder. In the situation being debated for the Board here, however, it is precisely because it is the (taxable) regulated entity spending the money that a tax saving arises. Further, that tax saving is made up, dollar for dollar, of money collected from ratepayers to pay tax. If benefits are truly to follow costs, the shareholder has no benefits to receive, but the ratepayers, who would be providing the tax money in the first place, should not have to pay it if it is not needed for tax costs.

174. The standalone principle is a longstanding and well-accepted regulatory principle, and the School Energy Coalition supports its continued use. However, Ms. McShane and the Coalition of Issue Three Distributors seek to give an interpretation to that principle that is inappropriate in Ontario and produces results that are unfair to the ratepayers.

175. The standalone principle has at its root the notion that a single corporate group (in the U.S., where corporate groups consolidate their accounting and tax filings) or corporate entity can have more than one business activity, some regulated and some not. In order to establish rates, the costs of the entity, including taxes, have to be allocated between those activities. Each activity in effect stands on its own, and is treated as if it were unrelated to the others. As we have discussed in detail in paragraphs 141 to 145 above, this principle cannot be applied in the same way when one activity creates a profit, and the other a loss, because the result is cross-subsidization, which is expressly contrary to this Board's regulatory principles and practice.

176. The level playing field argument is also enticing, except that as formulated in paragraph 46 of Exhibit B.9 it is an argument in desperate need of a target. The Draft Handbook, in Alternative 2, does not propose that it only applies to PILs paying distributors. Alternative 2 would, if adopted, apply to all distributors. A true level playing field would arise.

177. Of course, a variation on this argument is that, while electricity distributors owned by private sector interests can take deductions for non-recoverable expenses in another taxable corporate entity and get the tax benefits, that is not true for electricity distributors owned by the public sector. This variation is also incorrect. The difference is not a function of who

owns the distributor. Any distributor, whether privately or publicly owned, that has profitable unregulated activities can take its tax deductions in those unregulated entities. This would be true of many publicly owned distributors that have sister companies with unregulated businesses. If the shareholder wants to mine tax benefits, let it do so in the unregulated entities, and leave the ratepayers, and the money they pay in good faith to reduce the stranded debt, out of it.

178. A second variation on the level playing field argument is that there should be the same rules for electricity distributors as there are for gas distributors. As we have noted earlier, in paragraph 170, the gas distributors in Ontario have tight restrictions on what they can spend in the regulated entity, including limitations on both activities and capital structure, that make it difficult for them to use the utility as a tax shelter. Indeed, as we saw in the recent Enbridge 2005 rate case (RP-2003-0203), Enbridge Inc. engages in complex inter-company tax planning activities throughout the corporate group, but the gas distributor, Enbridge Gas Distribution, is excluded from those activities. Therefore, even if the government's intent was to create a level playing field between gas and electricity distributors on this particular question the gas distributors are already tightly controlled.

179. Finally, Ms. McShane uses the "no harm to ratepayers" argument. Now, some principles are positive, and some principles are negative. A positive principle forms a justification for doing something. A negative principle prohibits you from doing something.

180. The "no harm to ratepayers" rule is a negative principle. It does not justify anything. Rather, as Ms. McShane agreed in reponse to questions from Ms. Chaplin, it is simply a threshold you must reach or else a proposed action is prohibited. Having met the threshold, it's value is spent, and the proposed action still requires justification by some positive rule or principle.

181. In this case, though, Ms. McShane failed to take account that only Alternative 2 meets the "no harm to ratepayers" test. Alternative 2 ensures that every dollar collected from ratepayers to pay down the stranded debt is used for that purpose. Alternatives 1 and 3, to varying degrees, require the ratepayers to pay down the stranded debt twice (see para. 163-166 above).

182. In her direct evidence, Ms. McShane led a new piece of evidence, Exhibit D5.1, which suggests that if Alternative 3 is not selected, distributors will not be able to earn their allowed rate of return.

183. The problem with this piece of evidence, as shown in cross-examination of Ms. McShane (Tr 5-476 to 520) is that it completely begs the question. As Ms. McShane admits (Tr. 5-505 to 506), her chart is only correct if you assume her interpretation of the how the standalone principle should be applied is correct. (At another point commenting on the Chairman's bank example, she took the position that it misses the point because it isn't based on the standalone principle Tr. 5-345 to 350.) Bluntly, one must assume that the tax savings on

non-recoverable expenses should go to the shareholder. If you assume that, her numbers are correct. If you assume, as the School Energy Coalition believes and has argued above, that those tax savings are the ratepayers money and belong to the ratepayers, the chart shows that that conclusion produces the right return on equity.

184. In Appendix A, annexed to these Submissions, we have reproduced page 6 of Exhibit D5.1. The "McShane" and "Mintz" columns, reproduced from D5.1, show the ROE results if you assume that the ratepayers should pay the "standalone income tax", as Ms. McShane characterizes it, being not the actual tax payable but the pretend tax before the deductions in question. We have added to Ms. McShane's Exhibit two additional columns, "McShane2" and "Mintz2". These show the results if the tax amount on line 30 is not a pretend amount, but the actual amount of tax paid by the distributor. One can readily see that, if the ratepayers only pay the actual tax cost (just as they pay only actual costs of any other utility expense), Ms. McShane's approach would result in the utilities earning substantially above their allowed ROE, while Dr. Mintz's approach would leave them bang on the approved ROE. We note that all numbers are Ms. McShane's. We made nothing up. We just removed her assumption that the figures must produce the result she is supporting.

185. It is therefore submitted that, at best, Exhibit D5.1 has to be ignored, since it has no probative value of its own. At worst, from the point of view of the Coalition of Issue Three Distributors, Exhibit D5.1 demonstrates that unless the Board agrees that it is appropriate to recover more from ratepayers in taxes than are actually paid, and divert the difference to the benefit of the shareholders, only Alternative 2 produces the correct ROE for the shareholders.

186. Underlying the entire argument of Ms. McShane is a motif that should be addressed squarely. As she admitted in cross-examination (Tr.5-608), the real basis of her argument is that everyone else is doing this one way, and this Board should follow the crowd. She says, in fact:

"*So if you want to say, If it [ain't] broke, don't fix it, that's fine. I mean, that's essentially what I'm saying. And it's not just this Board, though; it's every regulator in North America has determined that the stand-alone approach to income tax is the way to set the income tax allowance.*"

There is no question that if a practice is common in other jurisdictions, it should be considered carefully for adoption in Ontario. On the other hand, at some point the Board also has to be satisfied that there is a substantive basis for the practice in the Ontario context. Here, the Coalition of Issue Three Distributors has provided no substantive basis to interpret the standalone principle in the way they propose, ie. that distributors should be given the authority to collect extra tax money from the ratepayers and keep it for themselves rather than pay it in tax, thus subsidizing their unregulated activities. It is one thing to say something is OK because "Everyone else is doing it". It is another thing to persist in that approach in the face of clear evidence of the harmful results it will cause.

187. ***Non-Recoverable and Disallowed Expenses -Charitable Donations***. A specific example of an expenditure that could be in part non-recoverable is charitable donations. On page 74 of the Draft Handbook, and consistent with our submissions above, it is submitted that the Board should adopt Alternative 2.

188. We note that, in other parts of these Submissions, we support recoverable spending by distributors on charitable activities within their local communities. LDCs should be good corporate citizens, and part of that is spending on local charities.

189. However, charitable activities are also a particularly difficult temptation for publicly-owned shareholders, since there is a material overlap between some types of charitable activities and the social and cultural spending by municipalities. If Alternative 1 or 3 is adopted, then in addition to the charitable spending that the distributor would otherwise do as a good corporate citizen, it is in the financial interest of the shareholder to have them spend non-recoverable amounts on charitable activities that would otherwise be municipal responsibility. If the town would otherwise be spending $1,000,000 on homeless shelters, why would it not cause the distributor to spend that money, and generate a $350,000 tax saving for the benefit of the municipality?

190. It is submitted that everyone will agree that would be wrong, but we disagree on how to prevent it. Rather than this Board establishing a series of prohibitions to cover every type of abuse like this, it is submitted that taking away the financial incentive is the simplest and most elegant way to get the right result.

191. ***Non-Recoverable and Disallowed Expenses -Interest Deduction***. Another specific example of this issue is found on page 78 of the Draft Handbook, the deductibility of interest. The Submissions set forth above apply equally to this issue, but there are two other considerations that need to be addressed.

192. First, the Board will note that there are four Alternatives on this issue. The reason is that in addition to spending more on interest than is recoverable in rates, the distributor could also spend less, thus increasing taxes/PILs and increasing rates. This possibility does not generally arise with other non-recoverable items.

193. Therefore, for this sub-issue one can start by looking at the possibility that a distributor will set up its capital structure or terms to decrease its interest expense. For utilities owned by municipalities, this is really an issue of prudence. The Board stipulates a particular capital structure for LDCs, and calculates a deemed interest expense that is included in rates. For a utility that is owned by a municipality, the shareholder will be indifferent as to whether it receives its return as interest or dividends (neither is taxable, because the shareholder is tax-exempt), so the only impact of reducing the interest component would be to increase utility taxes and therefore rates. Since there is no benefit to doing so, the utility should keep the interest at the maximum allowed level in order to keep taxes and therefore rates as low as

possible.

194. Contrast this with the utility owned by the private sector. If the taxable parent company is providing both debt and equity financing, it will typically prefer equity from a tax point of view, since the return through dividends is tax free. Thus, if the privately-owned LDC is allowed to calculate taxes based on actual interest expense, it is incented to reduce interest expense, which increases utility tax and rates, and reduces parent company taxes, thus increasing parent company after-tax profits.

195. To avoid this inappropriate incentive, it is submitted that Alternative 2 – deduction of actual interest expense – should not be adopted. Privately-owned utilities should not be allowed to shift tax obligations from unregulated parent to regulated utility by changing the capital structure.

196. Once Alternative 2 is removed, the other three Alternatives are the same as the three for each of the other related issues, but the order is different. Alternative 1 for interest is the same as Alternative 3 on page 72, ie. tax savings to shareholder. Alternative 3 for interest is the same as Alternative 2 on page 72, ie. tax savings to ratepayers. Alternative 4 for interest is the same as Alternative 1 on page 72, ie. shared savings.

197. Once we are down to the same three Alternatives, the Submissions set forth under the general question all apply to this specific example. Any interest in excess of the amount recoverable from ratepayers will produce additional tax savings, and for all the same reasons those savings, otherwise collected from the ratepayers to pay taxes, should not be collected for that purposes and then diverted to the shareholder's use.

198. We note, however, that in the case of interest the fifth reason – the nature of the incentive being given to the shareholder – is of particular importance. Many distributors are owned by tax-exempt municipalities, and are financed by both debt and equity from their parent municipalities. The total amount the ratepayers should pay as return on the debt and equity is mandated by the Board, so the dollars received by the municipality are fixed. Whether those dollars are received as interest or dividends doesn't matter to the municipality, since it is tax free. If increasing the debt and reducing the equity of the utility creates a significant tax saving, and that saving is allowed to be paid over to the shareholder, it is in the financial interest of the municipality to mandate either a higher interest rate on its distributor debt (thus increasing interest and reducing dividends), or a higher debt equity ratio, or both. In eiither case, by undermining the capital structure or terms of the utility, the shareholder can scoop some of the money ratepayers have paid for taxes, and instead use that money for the shareholder's purposes. The effect is to increase the effective cash on cash return paid by the distributor to the shareholder (see, eg. Tr. 1-705 to 717).

199. Take a simple example. The utility is financed \$1,000,000 (50%) through municipally-owned debt at a mandated interest rate of, say, 5%, and \$1,000,000 (50%) through

municipally owned equity at a mandated ROE of (to make the calculations easier), 10%. The municipality is entitled to receive $50,000 in interest and $100,000 in dividends, total $150,000, from the distributor, and that is the amount that is recovered in rates. The overall return is 7.5% ($150,000 on $2 million). If the shareholder changes the debt equity ratio to 90:10, that same $150,000 (which is still collected from the ratepayers) will be paid $90,000 in interest (5% on $1.8 million of debt) and $60,000 in dividends. But, there is an additional tax deduction for interest of $40,000, producing $14,000 in incremental tax savings. This can also be dividended out to the shareholder, increasing the overall return to $164,000, or 8.2%. The additional return comes from diverting money collected for taxes and paying it to the shareholder instead. Clearly there is a significant financial incentive to the shareholder to increase the interest component of the return, and decrease the dividend component.

200. It is submitted that a structure that makes it better for the shareholder to undermine the Board mandated capital structure is inherently flawed, and for this reason, and for the general reasons set forth earlier, it is submitted that the Board should adopt Alternative 3 on this issue.

201. ***Non-Recoverable and Disallowed Expenses - Eligible Capital Expenditures on Purchased Goodwill***. When a company is purchased, the buyer can acquire assets or shares, or can amalgamate. If shares are acquired, or if the entities amalgamate, there is no purchased goodwill. However, if the assets are acquired, and a premium is paid over book value, some portion of that premium may be allocated by the parties to goodwill. Where that is the case, the Income Tax Act provides that half of that purchased goodwill can be deducted for tax purposes, spread equally over the next seven years, as “eligible capital expenditures”, or ECE. ECE for purchased goodwill is not recoverable in rates, but it does reduce taxes each year that it is deducted. It cannot be shifted to other entities, or applied to reduce the taxes of other profitable activities, because it is inherently connected to the utility assets that were purchased in the first place.

202. All of the same considerations go into this sub-issue as we have discussed earlier with respect to non-recoverable expenses generally. However, here there is a twist. In those cases where ECE on purchased goodwill still exists in 2006, the entities that acquired those utility assets have no way of earning any return on their purchase premium except through the tax savings ECE generates. The allowed rate of return for the utilities purchased is set based on book value only. The premium would otherwise be lost money to the purchaser.

203. The problem here is not one of tax benefits, though. The problem lies in whether a purchase premium should attract a rate of return. If the policy decision is that it should not, then like all non-recoverable items the ratepayers’ tax money should not provide a return through the back door. If the policy decision is that the purchase premium should attract a rate of return, then it should be done overtly and transparently, and the return should be calculated in a clear manner based on balancing the interests of the ratepayers and the shareholder.

204. As an aside, it is the view of the School Energy Coalition that, if a purchaser of a distributor can generate economies of scale or other savings from combining the purchase with their other activities, some part of those savings should be used to provide a return to the purchaser on their purchase premium. That is the fair result. However, that result should be implemented in a disciplined manner, so that the resulting return is fair, and there are appropriate protections for both shareholder and ratepayers.

205. The back-door tax subsidy of purchase premiums is not appropriate, and therefore for this reason and for the reasons set forth in our general submissions earlier, it is submitted that the Board should adopt Alternative 2 at the bottom of page 73 of the Draft Handbook.

206. ***Non-Recoverable and Disallowed Expenses - Fair Market Value Bump – ECE and CCA Calculations***. The final example of this general issue is found at the top of page 73, where the three alternatives are the same as the general alternatives, and on page 77, where Alternative 1 is equivalent to general Alternative 2 (ie. tax savings to ratepayers), and Alternative 2 is equivalent to general Alternative 2 (ie. tax savings to shareholder).

207. In brief, in 2001 electricity distributors were required by the Ministry of Finance to revalue their assets to fair market value (for tax purposes only, and not for accounting purposes). In general, values were increased over book value. This generated ECE on goodwill, which is dealt with in the Alternatives on the top of page 73, and it generated higher undepreciated capital cost for depreciable assets, thus increasing annual CCA deductions, which is dealt with in the Alternatives on page 77.

208. The general submissions on the tax impacts of non-recoverable expenses apply equally to this issue.

209. However, there is an additional consideration that should be taken into account. The effect of this change in the tax rules was, effectively, to lower taxes for the distributors. Normally, if taxes are lowered, for example through lower rates, or through greater deductions made available, the lower taxes are reflected in rates. It is no different here. The tax rules were changed to decrease taxes, and like any change in tax rules the cost or benefit should flow through to ratepayers.

210. It would be different if the Ministry of Finance or other government officials had said that this tax change was intended to benefit the municipal shareholders, not the ratepayers. Nothing of the sort was said. Therefore, this Board should treat that change in tax rules like any other change in tax rules, and flow through the benefit of that reduction in taxes to the ratepayers. To do that, the Board should adopt Alternative 2 at the top of page 73, and Alternative 1 on page 77 of the Draft Handbook.

211. ***Conservation and Demand Management Expenditures.*** On page 81 of the Draft Handbook, there is a placeholder for the impact of C&DM expenditures on the calculation of PILs or taxes. It is submitted that the method used in the 2005 PILs model, in which C&DM

expenditures are expressly set out and their impact on PILs or taxes calculated for the rate year, is the appropriate method of accounting for the tax impacts of C&DM in 2006. This would include, for example, expenditures of the utilities in 2006 from their 2005 C&DM plans. Those expenditures cannot be included in 2006 rates, of course, because they have already been included in 2005 rates, but they are still deductible for tax purposes and therefore should be accounted for in the amount of taxes recoverable from ratepayers in rates.

212. We therefore propose that the Board include, in Section 7.1.2.15, the following:

"*The applicant must identify all C&DM expenditures expected to be made in 2006 that are not otherwise included in their distribution expenses or amortization recovered in rates, including without limitation all expenditures from the applicant's 2005 C&DM Plan that are planned for 2006, and shall record all such expenditures on Sheet XX of the 2006 OEB Tax Model. That Sheet then calculates the reduction in PILs or taxes that will result from the deductibility of all or part of those C&DM expenditures*."

213. ***Smart Meters Expenditures.*** Also on page 81, there is a placeholder for Smart Meters tax impacts. For the same reasons it is submitted that the Board should use a similar approach to C&DM to deal with the tax impacts of smart meter expenditures in 2006.

214. We therefore propose that the Board include, in Section 7.1.2.16, the following:

"*The applicant must identify all smart meters expenditures expected to be made in 2006 that are not otherwise included in their distribution expenses or amortization recovered in rates, including without limitation all smart meters expenditures from the applicant's 2005 C&DM Plan that are planned for 2006, and shall record all such expenditures on Sheet XX of the 2006 OEB Tax Model. That Sheet then calculates the reduction in PILs or taxes that will result from the deductibility of all or part of those smart meters expenditures*."

7.2.1 Minimum Information to be Provided with 2006 OEB Tax Model Filings

215. No submissions.

7.2.2 Future Tax Information Disclosure

216. ***Exceptions to the General Rule***. This section provides that distributors must file information on their actual taxes paid in 2006, when they are known, so that the Board and parties can determine whether the rules for taxes in this Handbook are striking the right balance between the interest of shareholders and ratepayers. Some distributors seek an exemption from this requirement if they do not have a separate tax return for the distribution portion of their business.

217. It is submitted that this proposal is disingenuous. Under Canadian tax rules, corporate entities do not file separate tax returns for their separate business activities. They file a single tax return for all of their business activities, sometimes but not always separating out the income and expenses of each, but in any case calculating the tax obligation on a consolidated basis. While there are some special situations in which separate tax filings are required within a single corporate entity, they are not the norm.

218. Therefore, what this proposal amounts to is a "Get out of jail free" card. Any utility that does not want to show the Board and its ratepayers how it actually spent the money it collected from ratepayers to pay taxes can simply "taint" the regulated entity with unregulated activities, then claim that their tax return isn't limited to distribution activities so they are exempt from filing.

219. There may be a very limited number of situations in which it is appropriate to bend this rule. Hydro One, which has both transmission and distribution in the same corporate entity and therefore the same tax return, comes to mind. It is submitted that the way to deal with this small number of situations is not to create a giant loophole, but allow those exceptional cases to be brought before the Board individually through a request for exemption from the Handbook's requirement in this area. Then, the Board can design an alternative that ensures that proper disclosure is made, but that fits the unusual circumstances of the particular applicant.

8. REVENUE REQUIREMENT

8.0 Introduction

220. No submissions.

8.1 Service Revenue Requirement

221. No submissions.

8.2 Service Revenue Requirement and Base Revenue Requirement

222. ***Non-Routine/Unusual Tier 1 Adjustments.*** Page 87 of the Draft Handbook, after the numbered paragraphs at the top, deals with the two Tier 1 adjustments relating to revenue. The first deals with revenues from embedded distributors, and is self-explanatory. The second deals with non-routine/unusual adjustments. We have three concerns with the way these adjustments are described:

(a) The draft says "an adjustment may be made". This is inconsistent with the rules relating to Tier 1 adjustments which are supposed to be mandatory.

(b) This refers only to non-routine/unusual events that produced revenue, but that limits the scope unduly. Revenue impacts could include revenue in 2004 that is unusual, or a lack of revenue in 2004 from a source that normally does generate revenue.

(c) Schedule 8-1, where the adjustments are to be reported, does not include the same level of detail as Schedule 3-2, where the equivalent adjustments to distribution expenses and rate base are to be reported. The format of Schedule 3-2 should be carried forward to an appropriate revenue schedule, perhaps a new Schedule 8-4.

223. We also note that the non-routine/unusual adjustment for revenue applies not only to revenue requirement, but also to load in Chapter 9 (at page 93). As we note there, it is not clear how these adjustments are related. It would appear to us that the adjustment in Chapter 8 is limited to regulated charges and other non-distribution revenue, but that is not clear from the wording in the Chapter. Additional explanation both in Chapter 8 and Chapter 9 of revenue-releated Tier 1 adjustments may be appropriate to clarify how these adjustments work, individually and together.

8.3 C&DM et al Revenue Requirements

224. No submissions.

9. COST ALLOCATION

9.0 Introduction

225. No submissions.

9.1 Customer Classes

226. ***No Changes for Re-Allocation of Costs.*** The third paragraph of section 9.1 on page 92 deals with distributors who wish to change their customer classifications. There may be many legitimate reasons why changes are necessary. However, it is also true that cost allocation and rate design are scheduled to be considered for 2007 rates, not 2006, and class changes in the absence of a disciplined look at cost allocation and rate design run a significant risk of being made on insufficient information.

227. Therefore, we propose that the following wording be added to the subject paragraph:

"Changes in customer classes should only be undertaken if there are unusual circumstances in which a change is clearly required, and it cannot wait until 2007. The Board has scheduled to review cost allocation and rate design for 2007 rates, and applicants should consider whether any changes to customer classes would be better incorporated into that more rigorous review. In particular, changes in customer classes that arise because of the applicant's concerns about cost allocation or rate design issues will receive a higher level of scrutiny so the the Board can be satisfied that they should not be dealt with as part of the cost allocation review."

9.2 Determination of the Appropriate Share of 2006 Revenue Requirement…

228. ***Default Allocation of Revenue Requirement.*** It is not clear to us, after considerable review, how the proposed default cost allocation between classes is supposed to track the allocation for either 2004 or 2005. While it would appear to be possible that it will cause shifts between classes from 2004 or 2005 to 2006, the narrative description does not provide sufficient detail to determine whether that is the case.

229. We believe that a statement of cost allocation principle might be of assistance, not only in understanding the methodology, but also for distributors to understand where an adjustment might be appropriate. For example, the narrative could say:

"*The intention of this cost allocation model is to allocate costs to customer classes in the same proportions as costs were allocated on average in 2002 through 2004, but with adjustments where the number of customers or the throughput of any class has undergone a* *material change*."

230. ***Adjustment for Gain or Loss of Major Customer.*** As we have noted earlier, it is not clear how the adjustment for gains or losses of load, which is a Tier 1 adjustment, relates to the revenue adjustment in Chapter 8. If, as we believe, Chapter 8 adjusts only for non-distribution revenue offsets, and adjustments driven by load are dealt with only in Chapter 9, this should be made explicit.

231. Of more concern, in our view, is the lack of detail in the reporting of load adjustments. These adjustments could easily have a larger impact on final rates than the adjustments to distribution expenses or rate base set forth on Schedule 3-2, yet little in the way of reporting appears to be required. It is submitted that a Schedule 9-4, similar in content to Schedule 3-2, should be added to require detailed reporting of these Tier 1 adjustments relating to load.

232. We also note that the "Gain or loss of a major customer" section on page 93 appears to be limited to customers that are entirely new, or are entirely gone. We have seen a number of examples over the past few years where customers remain, but a significant change in their operations means that the load is materially increased or decreased. For example, a customer on layoff during 2004, but now back in full production, could have a material impact on 2006 rates. Similarly, a customer that had a manufacturing operation, but has changed to a warehouse operation, as happened with one utility recently, could also have a material impact on 2006 rates. We believe that the adjustment on page 93 should be expanded to take these into account.

233. Finally, we note that there is no materiality test for this section. We believe that the test that has been used elsewhere – 2% of distribution revenues – should be expressly set forth in this paragraph to make clear that this is a mandatory adjustment with a fixed threshold.

234. ***C&DM Program Impacts.*** We have dealt with issues relating to C&DM in Chapter 16 below.

235. ***Smart Meters Program Impacts.*** We are concerned that the applicants are not being given any guidance on page 94 of the Draft Handbook as to how to adjust load for impacts relating to smart meters. The Handbook appears to leave applicants to estimate this impact on their own. Given the lack of experience in this initiative, and the varying levels of load forecasting expertise amongst the distributors, this would appear to create a potential for widely varying estimates of load reductions, and therefore widely varying rate impacts.

236. It is submitted that there are two ways smart meters load adjustments can be made without this problem:

(a) The Board can stipulate, as part of its smart meters implementation plan, a formula or formulae for adjusting load based on smart meter implementation targets for the rate year, by class. This is a sensible part of the smart meters process (since the expertise in determining these adjustments relates more to smart meters than to normal load forecasting), and would provide a consistent method of adjusting for all utilities. The formulae could in fact be built into the 2006 EDR Model in its final form, so that this section of the manual would simply require the applicant to fill in their smart meters plan targets by class for 2006. The Model would then calculate and adjust for the load impacts of those levels of smart meters installations.

(b) If it is not possible to establish standard load adjustment approaches by the time the model is released, an alternative approach is to allow distributors to establish a variance account for smart meters lost revenue (much like a C&DM LRAM), which can then be cleared in a subsequent year. By the time the account needs to be cleared, there will be sufficient experience with smart meters around the province that load impacts will be fairly well known, and lost revenue that should be in the variance account can be readily calculated.

237. If the Draft Handbook is left as it is, we are concerned that the tendency will be to overestimate lost loads from smart meters, thus driving up rates for 2006. Since there will be no mechanism to true this up after the fact (as would be the case with an LRAM), any overestimation of the impact of smart meters would accrue to the benefit of the shareholders and be an unnecessary cost to the ratepayers.

9.3 Determination of Appropriate Shares of Other Revenue Requirements

238. ***Regulatory Assets Allocations to Classes.*** The Draft Handbook contemplates that in same cases the revised allocations of Regulatory Assets will not be available for distributors in time for 2006 rates. It was our understanding that some distributors were to implement the revised cost allocations in 2005 (adjusting for the first year over the next three), and the remainder in 2006 (adjusting for the first two years over the next two). Given the significant impact that these re-allocations have on some rate classes, it is submitted that any further delay beyond 2006 would be unfair, and would generate too big an adjustment in the fourth and final year of the payment period.

239. Therefore, it is proposed that the last paragraph on page 94 be replaced with the following:

"*It is the responsibility of each applicant to ensure that they apply for a Phase II regulatory assets order in time to implement that order when received as part of 2006 rates*."

10. RATES AND CHARGES

10.0 Introduction

240. No submissions.

10.1 Fixed/Variable Split

241. ***Differences Between 2004 and 2005.*** Page 101 of the Draft Handbook proposes that the fixed/variable split in 2004 will be applied to rate design for 2006. However, we note that the 2005 RAM Model adjusts the fixed/variable split for most classes and most distributors. While some distributors have proposed a partial reduction of that adjustment, no-one, to our knowledge, has proposed that the 2005 fixed/variable split be the same as 2004. Therefore, if the 2006 Rate Handbook is left as it is, there will be a changed in fixed/variable split for all customers one way in 2005, and back the other way in 2006. It is submitted that this is not good ratemaking.

242. Therefore, subject to our comments below on province-wide variations in fixed charges, it is submitted that the appropriate approach for 2006 is to apply the formula as proposed, but using the data – the fixed/variable split - from 2005 rates rather than 2004.

243. ***Province-Wide Variations in Fixed Charges.*** We are this week making submissions with respect to 2005 distribution rate applications that include a proposal to narrow the gap between fixed charges around the province, as a transition to cost allocation and rate design changes for 2007 and in order to minimize rate shock driven by cost allocation and rate design. If that proposal is accepted, it contemplates a similar adjustment for 2006. For convenience of the Board, our submissions in this regard for 2005 are repeated in these Submissions, with the appropriate modifications to wording where applicable.

244. The Board is already acutely aware that fixed monthly charges across the province have a surprisingly large range. This represents a challenge to the Board's mandate to set just and reasonable rates, since it is unlikely that geographic differences or other externally valid factors account for a significant part of the variation in fixed charges.

245. Cost allocation and rate design issues are scheduled for consideration and implementation in the 2007 distribution rates, with additional harmonization taking place mainly in 2008 and beyond. The concern will be that, to the extent that those processes impact the fixed/variable split – which they must inevitably do – there will be substantial bill impacts for individual customers or customer groups. This will be particularly true where the fixed/variable split for a distributor or for a particular class is strongly divergent from provincial averages. For schools, this is of considerable importance, since a) schools are especially vulnerable to large

rate shifts due to their relatively inflexible budgets, and b) schools are funded similarly throughout the province, but experience major differences in some costs, of which electricity distribution can be one of them.

246. The School Energy Coalition believes it would be in the interests of the ratepayers and the distributors to make some initial steps in the direction of harmonization of fixed charges in 2005 and 2006, rather than waiting until 2007 or 2008 and having a single major shift. We believe that, since the Board can be relatively certain today that some form of mitigation will be needed when the fixed/variable splits are reviewed and/or harmonized, it is appropriate to get started on this now, in order to smooth the impacts over several years.

247. To this end, the School Energy Coalition has proposed that utilities with very high fixed charges in a class (relative to the median across the province) be required to reduce their fixed charges in that class by a small amount in 2005 and again in 2006, and utilities with very low fixed charges in a class (relative to the median across the province) be required to increase their fixed charges in that class by a small amount in 2005, and again in 2006.

248. Our specific proposal for 2006 is as follows:

(a) If the fixed monthly charge in any of the residential, GS<50, or GS>50 classes of a distributor is 20% or more greater than the median of the fixed monthly charges for that class throughout the province (on a 2006 as filed basis), the distributor should be required to reduce the fixed monthly charge for that class in 2006 by 10% and re-allocate the revenue requirement to the volumetric charge. This adjustment should be calculated by Board staff after all applications have been filed, and applied to the 2006 EDR Model results of each utility affected.

(b) If the fixed monthly charge in any of the residential, GS<50, or GS>50 classes of a distributor is 20% or more lower than the median of the fixed monthly charges for that class throughout the province (on a 2006 as filed basis), the distributor should be required to increase the fixed monthly charge for that class in 2006 by 10% and re-allocate the revenue requirement to the volumetric charge. This adjustment should be calculated by Board staff after all applications have been filed, and applied to the 2006 EDR Model results of each utility affected

249. It is submitted that, if the Board adopts a proposal such as this one for 2005 and 2006, the impacts on individual customers in 2005 and 2006 will be small, but by 2007 and 2008 the range of variation of fixed charges will have been reduced throughout the province, making the impact of changes at that time less onerous. For schools across the province, the result will be a more gradual move toward consistent charges, reducing over time one component of the large cost differences between schools for the same service, and reducing the impact of any changes that will take place in 2007 or 2008.

250. Attached at Appendix B is a list of fixed charges for each of the affected classes for 2005, together with our proposed adjustments to those fixed charges for 2005, based on the information we have obtained from the 2005 rate applications. This can be taken as indicative of the impact that would occutr for 2006 if this proposal is adopted.

10.2 Unmetered Scattered Loads

251. ***Reliance on Impact Evidence.*** A consensus was formed supporting an interim solution to the problem of varying rate treatment of unmetered scattered loads throughout the province. Part of that consensus was an allocation of the cost of adjusting the unmetered scattered load rate to all rate classes, which clearly was not the most appropriate cost allocation approach. It allocated parts of the cost to some customers who should not bear it, and it did the re-allocation without any cost allocation study or cost causality data. Despite this, the School Energy Coalition, adopted the consensus, and continues to support it.

252. The consensus was reached on the basis of anecdotal evidence that the impact across the province of this cost re-allocation was minimal. Some evidence indicated that the total re-allocation would be less than $1 million, and generally it was agreed that the re-allocation could not exceed $3 or $4 million. This allowed those who would have preferred a proper cost allocation study to support the consensus.

253. Given the evidence before the Board that the impact is not known with accuracy, it is submitted that the Board should require applicants to which paragraph 2 on page 102 of the Draft Handbook applies to file, with their application, a calculation of the rate impacts of the change to the unmetered scattered load rate. When all applications are in, the Board will be able to confirm that the impact is sufficiently small to justify the interim solution adopted. Conversely, if the impact is very large (e.g. $20 million as opposed to $2 million), the Board can consider at that time, based on empirical data, whether the appropriate rate classes are bearing the appropriate costs for this interim solution.

10.3 Time of Use Distribution Rates

254. No submissions.

10.4 Transformer Ownership Allowance

255. No submissions.

10.5 Update of Loss Adjustment Factor

256. No submissions.

10.6 Distributed Generation

257. ***Introduction of New Allocation Methodology.*** The School Energy Coalition supports the rapid introduction of distributed generation. However, on page 104 of the Draft Handbook Alternative 2 proposes a new methodology to re-allocate transmission savings caused by new distributed generation. It is submitted that this new methodology is being proposed without a proper evidentiary base, and in particular without any analysis of the impacts on other customers of the change. Therefore, it is submitted that this Board ought not to approve this new methodology at this time, but should instead adopt Alternative 1 above.

258. Proponents of the new methodology argue that because it applies to new generation only, it will have no impacts on the bills of existing customers. No evidence has been provided of this conclusion, and it is in fact counterintuitive. Typically distributed generation will not drive an immediate reduction in the costs of the transmission utility (although it may do so over time). Rather, it may create a drop in the transmission charges to a given distributor, but this will usually mean an increase in transmission charges to other distributors to generate the same revenue requirement for the transmission company.

259. All of this, of course, is open to dispute, but that is exactly the point. Without evidence of the actual impacts that will occur from changing the methodology, it is impossible for the Board to determine how this will bear on setting just and reasonable rates.

260. Our alternative proposal, therefore, is as follows. The Board should adopt Alternative 1 for the purposes of the Handbook, thus retaining the status quo. In the event that any distribution company, either as part of its 2006 rates, or subsequently, wishes to adjust its allocation of transmission charges to reflect the value of a new distributed generation plant proposed for its franchise area, it should file with the Board a request for a rate adjustment. The distributor should be required to include in its application a detailed rate impact analysis showing the net cost, if any, to other ratepayers of the change proposed. The distributor should also be required to provide notice to the transmission company of its application, and the transmission company should be asked to file an impact analysis with respect to transmission costs and charges. In this way, when the change is actually needed it will be made by the Board, if at all, on solid evidence, and the Board will thus be able to determine the exact change that fairly balances all interests.

261. In the event that no distributor makes such an application in 2005, the issue of the allocation of savings from distributed generation should be considered by the Board either in the next Hydro One transmission rate application, or in the 2007 cost allocation and rate design process.

10.7 Standby Charges

262. No submissions.

10.8 Low Voltage Charges

263. No submissions.

10.9 Demand Determinants

264. No submissions.

10.10 Recovery of Regulatory Asset, C&DM, and Smart Meter Revenue Requirements

265. ***Regulatory Assets.*** We note that page 107 of the Draft Handbook indicates that Regulatory Assets are to be allocated based on volume. This is inconsistent with the Decision of the Board on December 9, 2004, relating to Regulatory Assets. It is submitted that this wording should be adjusted to be consistent with that decision.

266. ***C&DM Costs.*** We have made submissions on C&DM in Chapter 16.

267. ***Smart Meter Costs.*** The recovery of smart meter costs is an issue in a parallel process. It is submitted that this draft of the Handbook should stipulate that the recovery of smart meter costs will be determined by the Board as part of the Smart Meters implementation planning process, and the 2006 EDR Model will be adjusted accordingly.

11. SPECIFIC SERVICE CHARGES

268. No submissions.

12. OTHER REGULATED CHARGES

269. No submissions.

13. MITIGATION

13.0 Introduction

270. No submissions

13.1 Impact Analyses

271. No submissions.

13.2 Mitigation Methodologies

272. ***Comparison of 2005 Rates of LDCs.*** The School Energy Coalition has, in its submissions on 2005 distribution rate applications, made a proposal to require mitigation plans by distributors that have much higher than average bills to their customers. This proposal would be implemented in part at the end of the 2005 rate process, and in part at the commencement of the 2006 rates process. Therefore, for the convenience of the Board we have replicated those submissions here in paragraphs 273 through 285.

273. Of serious concern to the School Energy Coalition is the wide range of overall distribution costs between distributors and franchise areas throughout the province. While many of the differences between rates and bill impacts from place to place around the province are the result of geographic, demographic, historical, and other factors beyond the control of utility management, from a ratepayer point of view enormous differences in the price of the same service, sometimes delivered within a few kilometers of each other, raise questions about whether those prices are just and reasonable.

274. For example, where a high school in Belleville (one of the cheapest places in the province for a school to obtain electricity service) would have an annual distribution cost only one-fifth the level it would pay if it were in nearby Napanee (which is already well below the provincial average), that is an anomaly that needs to be addressed. When that same high school, if located in Toronto, would have a bill more than fifteen times the level of Belleville, and more than double the provincial average, that is a serious concern that needs to be considered.

275. To investigate this issue, the School Energy Coalition has developed a model that tests rates from various distributors against the usage of sample schools. The results of that model for 2005 are presented in Appendix C to these Submissions. The model applies the applied for rates for 2005, for each of the distributors or, where they have multiple rate schedules, for each of the franchise areas, to the energy usage of those sample schools, and so produces an

"apples to apples" comparison of the cost of electricity distribution for schools in the various areas of the province.

276. The model starts with energy use data for three typical schools. Sixty-six schools across the province were profiled, and from this sample the electricity use profiles of the three typical schools were developed. Those schools are a typical small school, like an elementary school, a typical medium school, like a large elementary or middle school, and a typical large school, like a high school. While individual schools throughout the province differ, these samples are a useful tool to make rate comparisons.

277. From the 2005 rate applications, we have taken the applied for rates for 2005, for each different rate schedule. The model then calculates the annual bill for each size of typical school, the mean and median for all franchise areas for a school of that size, and the variance of each distributor's bill for that size school from the median. Additional non-commodity charges are then added to produce the total non-commodity bill, and then commodity charges (at 2004 rates to be consistent) are added to produce the total electricity bill.

278. Appendix C has two components. Pages 86 to 89 are the school bills at the distribution rates applied for in 2005, with a comparison to median for each of the three school sizes sorted alphabetically. Pages 90 to 93 are the same list sorted by most expensive to lease expensive for a small school.

279. What the results in Appendix C show is that the cost of electricity distribution for a small school varies more than 1900% across the province, with the high being almost 300% above median, and the low being almost 80% below median. For a medium school, the cost of electricity distribution varies 2200% across the province, with the high being more than 240% above median, and the low being more than 80% below median. The large school has the biggest variation – more than 4000% across the province - , with the high being more than 240% above median and the low being more than 90% below median.

280. The School Energy Coalition, given its particular interest, has carried out these comparisons for a sample of schools. But there is no magic in the selection of the sample. A similar comparison done for sample residential customers (e.g. the samples used for the bill impacts on Sheet 13 of each 2005 RAM model), would produce similar wide variations, as would any other comparison of any of the sample customers used in the RAM model.

281. There are many reasons for these variations. Some of the reasons relate to the last five years of history, and the differences in profitability and overall revenue availability of individual distribution companies. Some of the reasons relate to a longer history, for example the evolution of cost allocation and rate design in different franchise areas. Some of the reasons are fundamental differences in the cost of delivering electricity in different parts of the province – differences driven by topography, geology, demographics, historical investment, etc. And, some of the reasons are the differing abilities of management of distributors to

operate their franchises efficiently.

282. The School Energy Coalition is aware that the Board has established a multi-year process for the review of electricity distribution rates. 2005 brings in the final third of MARR, and starts the change to a conservation culture. 2006 moves the revenue requirement forward to a 2004 base, and attempts to adjust forward from that so that most distributors are on a rough cost of service basis. 2007 addresses historical and other anomalies in cost allocation and rate design, and may perhaps deal with some other issues that have not been included in 2006. 2008 then moves cost of service closer to current costs, and as well may focus more on rate harmonization to the extent that previous years have not improved the situation. It also appears likely that, in 2006 through 2008, some form of cost and/or rate comparisons between distributors will be used to identify potential efficiency differences and highlight best practices.

283. On the other hand, a ratepayer can fairly ask the question: "How can rates be just and reasonable when there exist such wide variations, many of which cannot be explained by external factors?" The existence of these variations at the very least creates an urgency to investigate their cause, so that rates can become truly just and reasonable as quickly as possible.

284. Since many aspects of rate differentials will be dealt with in 2006 and beyond, we did not propose that the Board make any general rate adjustments in 2005 to correct these differentials. The Board must balance the urgency of fixing apparent problems with the practicality of keeping the regulatory process efficient and moving forward incrementally. The School Energy Coalition supports the Board's multi-year plan to get distribution rates where they should be, and does not propose that it be pre-empted because of this issue.

285. Instead, we proposed that the Board do the following:

(a) At the time it issues its decision with respect to the 2005 rate applications, the Board should prepare and publish (on its Web site) a comparison between all franchise areas/distributors of the monthly distribution charges for each sample customer listed in Sheet 13 of the 2005 RAM model. The comparison lists should in our submission be presented in a manner similar to Appendix C to these submissions, and should include maximum, minimum, median, mean, and variations from median calculations.

(b) In that decision, and in order to ensure that the published comparisons are not misunderstood by stakeholders or members of the public, it is submitted that the Board should prepare an explanation of the various reasons why rates can differ from one area to the next, and a caution that the raw data comparison is only a starting point to a review of the reasons for the disparities.

(c) The Board should, either in the 2006 Rate Handbook or in the 2005 rate decision, require each applicant whose charges to any of the standard sample customers are more than 20% above the provincial median (a "Major Variance") to report to the Board as part of or prior to their 2006 rate application:

(i) Advising the Board in detail the primary reasons for each Major Variance, including in particular any reasons that are driven by 1) higher than average costs of the utility, 2) cost allocation and rate design anomalies, and 3) historical problems with their rates;

(ii) Where any Major Variance is capable in whole or in part of being reduced or eliminated, a plan for reducing or eliminating such Major Variance in 2006 or in multiple years, including an analysis of options and the reasons for selecting the plan proposed; and

(iii) Where any Major Variance is not capable of being reduced or eliminated, the reasons why the Major Variance should be allowed to remain outstanding.

286. ***Mandatory Filing Requirements for High Priced LDCs.*** The School Energy Coalition's proposal in 2005 thus requires, in most cases, that high priced LDCs be required as part of the 2006 rates process to develop and file a mitigation plan. As the Chairman noted in questions of Mr. Hasbrouck (Tr. 4-1275 to 1293), that plan may be something like "We can't think of a plan", or "This can't be fixed", or something like that, but the requirement would be to put their minds to the issue and determine whether anything can be done.

287. It is submitted that this is the most suitable starting point for the discussion of rate impacts in 2006. Without a requirement going in to put their minds to mitigating the impacts of their application, the utility management are basically being left to respond only to criticism. That is not good management. It is much better if applicants are advised, up front, that it is first and foremost their responsibility to figure out how to deal with the bill impacts of their application. If there is a problem, because rates or high or because the rate increase is high, it is not up to the Board to figure out how to solve it. Before the Board even looks at the application, the utility's management should have looked at the problem and proposed a solution. In our submission, the Rate Handbook should establish this expectation in a clear and uncompromising way.

288. In addition to being the right thing to do, it is submitted that this approach will produce a better outcome, on two counts:

(a) First, it empowers utility management to solve the problems of their own utility, with the result that the applicant does not present the Board with a problem, but with a problem and a proposed solution. This means that the Board and intervenors do not start off being critical of the utility and its management, but are more constructive in working with them to either make their solution work, or modify it into one that does. In our submission, placing primary responsibility for mitigation planning on management, before an application is filed, is likely to generate a more co-operate and positive regulatory process, with less conflict and lower regulatory burden.

(b) Second, this approach taps the creativity and local knowledge of the utility's management. Far too often intervenors and even the Board, located as most of us are in Toronto, think that they are best able to solve local problems. One of the strengths of the local distribution companies is their local knowledge. This is a resource that should be tapped where rates or rate increases are high. Not only is this likely to generate better locally acceptable solutions, but in some cases creative solutions from one distributor can be applied to similar mitigation issues faced by other distributors.

289. We note that the discussion in the oral hearing amongst the mitigation witnesses focused on rate increases. We support the proposals of the Vulnerable Energy Consumers Coalition with respect to the filing of mitigation plans for applicants with large rate increases proposed for 2006.

290. On the other hand, we believe that, while the size of rate increases is important, from a ratepayer's point of view of equal importance is the comparative cost of the service. For ratepayers like schools, that have similar operations throughout the province, the fact that a local distributor has much higher prices than others around the province is an even bigger concern, and thus high prices should be a major factor in mitigation planning. So, for example, if a distributor has very low overall rates, as some do, a 20% increase in 2006 may warrant attention, but it may not be the end of the world as long as the overall cost is still below average. Conversely, if a distributor starts out 30% above the provincial median, a 5% increase, or even no increase, is cause for concern, because that distributor should be explaining why their prices are so high.

291. From the point of view of schools, it is of critical importance that high priced suppliers of this service be required to justify why they are out of step with provincial averages. While of course some adjustments have to be made for external factors, we believe there should be a de facto type of competition between the LDCs, and those that have higher prices than the "market" (ie. the provincial medians) should have a responsibility to try to get those prices closer to market.

292. ***Mitigation Issues to be Considered in Mitigation Plans.*** It is also submitted that it would be useful for the Board to give some guidance in the Rate Handbook on what types of things can be included in the mitigation plan. While rate mitigation is not new to most distribution companies, a formal analysis of it may be. The Board can assist by providing some framework within which the applicant can develop and present a mitigation plan.

293. To this end, we propose that the following components of a good mitigation plan be described in the Rate Handbook:

(a) A breakdown of the causes of higher than average rates or high rate increases, including:

(i) High costs due to external geographic, demographic or similar factors.

(ii) High costs due to historical problems or current unusual business issues.

(iii) High costs due to other factors.

(iv) Cost allocation or rate design anomalies.

(v) Class-specific costs or other factors.

(vi) Economic development or social priorities included in existing or proposed cost allocation or rate design.

(vii) Low starting point for class or overall rates, producing high increases to get back to normal levels

(b) Possible mitigation actions to consider, and discussion of why each is either used or rejected:

(i) Temporary or permanent reductions to operating costs in the rate year.

(ii) Delay of operating costs to a subsequent period.

(iii) Reduction or delay of capital program to reduce long term impacts.

(iv) Changes in financial structure to make it more efficient.

(v) Generating new sources of revenue.

(vi) Temporary or longer term reductions in shareholder returns (as some utilities have already implemented).

(vii) Shifting of economic development or social priorities out of the utility.

(viii) Spreading of rate increase over more than one year, with or without a deferral account to capture variances.

(c) Analysis of who bears the cost of mitigation depending on the plan selected, including:

(i) Employees or suppliers.

(ii) Shareholder.

(iii) Ratepayers in future years.

(iv) Ratepayers in other classes through cross-subsidization.

(v) Cost-less mitigation, such as increased productivity or reduction in discretionary expenses.

294. ***Comparison of 2006 Rates of LDCs.*** Finally, it is submitted that asking the distributors through mitigation plans to fix all price or cost disparities in one year is unreasonable. It makes much more sense, it is submitted, to assume that distributors will over a period of years, through plans such as these, get their costs and bills into closer line, both with each other and with an objective standard of an efficient utility.

295. In order to continue to encourage this direction, we propose that, when all rates have been established by the Board for 2006, the Board should publish the final rates and standard bill comparisons on its Web site in the same manner as we have proposed in paragraph 285 (a) above. A continuing comparison of the bills of LDCs will, we believe, by itself motivate utility management throughout the province to seek their most efficient operating levels.

13.3 Rate Harmonization

296. ***Proposals for Merged, Acquired, or Amalgamated Service Areas.*** On page 141 of the Draft Handbook are two Alternatives for rate harmonization. Alternative 1 allows applicants to include such requests in their 2006 applications. Alternative 2 requires that those requests be deferred until 2007.

297. We agree with the principle that rate-setting should generally be done in the context of disciplined and rigorous cost allocation and rate design. Therefore, most utilities that want to move in the direction of harmonization, either within their utility, or with neighbouring utilities, should wait and carry this out in the context of the 2007 process.

298. However, we can conceive of circumstances in which rate harmonization in 2006 would be appropriate, even without a full cost allocation process. We have, for example, proposed a narrowing of the fixed charges around the process in a step by step way, to avoid rate shock in future years. A number of distributors have similar situations in which they might be able to smooth the transition to new rates in 2007 by some partial steps in 2006.

299. Therefore, it is submitted that Alternative 1 is the appropriate choice for the Board to adopt in this case. We do suggest, though, that the Board add wording to the effect that rate

harmonization should generally be left until 2007, unless there are particular reasons (like transition changes) why some change in 2006 is more appropriate.

14. COMPARATORS AND COHORTS

14.1 Methodology

300. No submissions.

14.2 Filing Requirements

301. No submissions.

14.3 Publication of Price Comparisons

302. ***Proposal to Publish Price Comparisons with Explanations.*** In its submissions with respect to the 2005 distribution rate applications, the School Energy Coalition has introduced a proposal to compare the average bills of distributors across the province, and to require mitigation plans for the biggest outliers. That proposal, and its application to this 2006 process, is discussed under heading 13.2 – Mitigation Methodologies, above.

303. It is submitted that the comparison of distributors by price solves most of the data problems described by the Comparators and Cohorts experts, and deals with the primary issue of concern to ratepayers – overall price. Thus, it is a good first step to assist the Board in its comparison of distributors across the province.

15. SERVICE QUALITY REGULATION

304. No submissions.

16. CONSERVATION AND DEMAND MANAGEMENT

16.0 Introduction

305. ***New Chapter.*** As advised by the Board during the oral hearing, we are including all of our submissions relating to conservation and demand management under a new heading, Chapter 16. We understand that many of these issues may end up in a separate document solely for C&DM.

306. There is no separate issues list for C&DM, but the issues were canvassed at some length in the evidence of Mr. Chernik, Mr. Goulding, Mr. Gibbons, Mr. Heeney and Mr. Love. While the evidence was extensive, we will for the most part not make direct references to it, as the issues are clear. We have endeavoured to structure this Chapter to deal with the issues raised in a logical order.

307. In all our submissions in this important area, we are conscious of Mr. Goulding's statement in his oral evidence – "the perfect is the enemy of the good". We agree that C&DM could be hurt by trying to be too precise in what we do at this early point in the process. However, to the extent that the Board can impose some incremental discipline in this area, we believe that ratepayers and the public will be well served. It is also true, we note, that – "the sloppy, the slapdash, and the ill-conceived are the enemies of the good". As with many aspects of the Board's decision-making, the key is to find the right balance, in which we are as careful as possible, without caution becoming a barrier to action.

16.1 C&DM Plans for 2006

308. ***Who Should File a Plan?*** The C&DM issues for 2006 are considered against the backdrop of two important facts. First, while some distributors have a limited experience delivering C&DM programs, for most of them it is new, and they are moving up the learning curve. Therefore, as was clear in the oral evidence, the urgency with which the government, and most ratepayers for that matter, view C&DM has to be tempered with a need to make haste slowly lest money be wasted during the startup period. Second, almost all distributors have filed 2005 C&DM Plans that include very substantial spending targets, usually over two or three years. For many, those plans already include significant 2006 amounts.

309. That having been said, we believe that applicants that feel they are able to do more in 2006 than their existing commitments from the 2005 C&DM Plan should be encouraged to do so, and the Handbook should stipulate that the mechanism for this is the filing of a 2006 C&DM Plan. The 2006 C&DM Plan should contain only incremental 2006 spending, not spending included in the 2005 Plan.

310. ***Contents of 2006 Plans.*** The 2005 C&DM Plans were, as the Chairman noted in a number of comments in this hearing, necessarily more limited in their contents than would normally be expected of spending plans being considered by this Board. The Board dealt with those limitations by strict monitoring and reporting conditions, but everyone recognizes that is not a complete substitute for disciplined and rigorous planning going in. For the 2006 Plans, it is submitted that a more thorough presentation of options, programs selected, and results targetted, should be required.

311. In particular, the 2006 Plans should include at least:

(a) A full description of each major program proposed, and the rationale for its selection.

(b) A budget for each program, with a summary of how the budget was arrived at including sources of data for assumptions.

(c) A description of all steps taken to verify the feasibility of each program, including in particular contacts with channel partners, customer groups, and others whose participation is required.

(d) Target TRC savings for each program, including all assumptions used in calculating those target savings and the sources of those assumptions.

312. The 2006 C&DM Plans should be limited to customer side of the meter programs, as is the case with the gas distribution companies today. The 2005 C&DM Plans already for the most part contain substantial utility side of the meter programs, and there is no evidence that more are required for 2006. A focus on the customer side in 2006 is more likely to generate the "conservation culture" that is the current goal.

313. ***C&DM Stakeholder Consultative.*** The evidence is clear that the stakeholder consultation processes of Enbridge and Union Gas have, at least in the last couple of years, added considerable value to their successful conservation initiatives. It is also true that few conservation issues make it to the hearing stage in Enbridge's rate cases, because the thorough consultation means there is consensus on almost everything.

314. It may be that the new Conservation Secretariat will, over the course of time, take responsibility for common actions of the distributors, and their consultations with the various ratepayer and environmental groups that have an interest and expertise with respect to C&DM. In the meantime, we believe that the Board should take on this role, especially at this critical time when distributors have many C&DM opportunities, substantial available budgets, and limited expertise and experience in the field.

315. We therefore propose that the Board establish a joint Conservation Consultative, to review program design, monitoring, and evaluation. The Consultative can be managed by the Board,

but it would be preferable if the Board were to arrange for a group of larger LDCs to take charge of the process for the benefit of all LDCs in the province. The Coalition of Large Distributors, or another group of that type, may be an appropriate sponsor. Funding for the Consultative should be part of the costs process for the 2006 rates, to simplify the administrative details.

316. The Consultative should be established as soon as possible, and should be made up of utility, ratepayer, and environmental representatives. The first task of the Consultative should be to develop a roster of programs that have been reviewed and are available for use by any LDC in the province. In our view, the Consultative can identify such programs in two ways:

(a) By reviewing program lists from other jurisdictions to identify those that are likely to have potential in Ontario, and

(b) By receiving proposals from LDCs for programs they are considering for their own plans.

In the case of each proposed program, the Consultative should not only discuss and reach consensus on whether the program is suitable in Ontario, but also seek consensus on input assumptions, typical costs, expected penetration levels and TRC benefits, etc. We anticipate that the development of this roster will be an ongoing task, but that within a relatively short time a fairly extensive menu can be available for LDCs in crafting 2006 C&DM Plans. There is a great deal of information currently out there, so this work does not need to be done from scratch.

317. In proposing the establishment of a Consultative, we are not suggesting that it be granted any authority or decision-making power, nor that it be constituted as a formal ADR process. the 2006 EDR Process had no authority, nor was it a formal ADR, but in fact consensus was reached on most issues because all parties sought that goal. We believe the same will be true in the case of this Consultative, as it is currently true with the Enbridge and Union Gas DSM Consultatives.

318. In practice, we believe what will happen is that LDCs will have complete freedom to select for their 2006 C&DM Plans both programs that have been considered by the Consultative, and those that have not. However, LDCs will find that the “vetted” programs will have two advantages. First, they are essentially off the shelf, meaning that a lot of the more difficult tasks, like estimating participation rates and TRC targets, have been wholly or partly dealt with. Second, they are supported by a broad consensus, so the likelihood that there will be ratepayer or environmental opposition to a C&DM Plan based on these programs is much less.

319. Some parties believe that a Consultative such as this should have dedicated resources, such as a consulting firm, available to it. While activities of monitoring and evaluation, which would be added later to the responsibilities of the Consultative, will require technical

advisors, we believe that this is not necessary at the beginning. Between the utility sponsors, the environmental groups, and the ratepayer representatives there is sufficient experience in C&DM that the program components can be handled. If the Consultative needs technical support for particular tasks, it should have the ability through the sponsoring utilities to retain experts to assist as required, as is currently the case with both Enbridge and Union Gas.

320. We also propose that the Consultative be available to review program results for any LDC, again on a completely voluntary basis. Any LDC that has its results for a particular year, and wishes to have that audited or reviewed, can bring it to the Consultative, and the Consultative would supervise the audit of the results and report to the LDC on their conclusions/consensus. LDCs could also choose to have audits done outside of the Consultative process, but in practice we believe LDCs will prefer to have consensus when they bring their audits to the Board, for example for an SSM or LRAM approval.

321. ***Co-ordination with 2005 C&DM Plans.*** As we have noted above, we believe that the 2006 C&DM Plans should be incremental to, and more thorough than, the 2005 C&DM Plans.

322. Despite that, we believe that a distributor that elects to file a 2006 C&DM Plan, containing incremental 2006 spending, should file a reconciliation showing the combination of the 2005 C&DM Plan spending in 2006, plus the spending in the new Plan, with a description of how the two plans fit together.

323. ***Extended Filing Deadline.*** It is, of course, preferable that distributors file their 2006 C&DM Plans with their 2006 rate applications. However, we also understand that a well-thought-out plan may not be possible by the end of June, especially with all of the other responsibilities on the heads of the distributors.

324. Therefore, we propose that the distributors be expressly allowed to include in their 2006 rate application an incremental budget for 2006 C&DM, without actually filing a plan supporting that budget at the same time. We propose that there be two extended filing dates. For a normal 2006 C&DM Plan, the filing deadline should be September 30, 2005. However, if a distributor has a 2006 C&DM Plan made up solely of programs that have been reviewed and approved by the Consultative, the deadline should be November 30, 2005.

16.2 Principles Applicable to Establishing C&DM Budget

325. ***Target Budget Range.*** The Board heard a number of suggestions as to the appropriate range for C&DM spending in 2006. After hearing that evidence, we believe that utilities should be expected to spend between 2% and 4% of distribution revenues on C&DM in 2006, inclusive of money from their 2005 C&DM Plans. This would amount in most cases to just under 1% of gross revenues. While in future years we would hope that the range can move upwards, we are conscious that in this early year there is a danger that money will be wasted if we ask distributors to spend too much while they are still learning.

326. ***Exceptions.*** While most distributors are likely to come in between 2% and 4%, if that is the range proposed by the Board in the Handbook, there should be room for exceptions, in each case with an explanation.

327. In the case of utilities that seek to spend more than 4% of distribution revenues, they should be required to demonstrate:

(a) They have the expertise or capability to have a more aggressive C&DM Plan and implement it efficiently. This could be done simply by tabling a detailed and well thought out plan, or by leading evidence that the utility has established an internal infrastructure to deliver in this area, or whatever other proof is available to the utility.

(b) The short term bill impacts are not unreasonably negative. In most cases, this will be easy to show, as C&DM does not need to generate sharp rate spikes if it is delivered thoughtfully. However, a calculation of bill impacts should be required to ensure that this is the case for the most aggressive plans.

328. In the case of utilities that seek to spend less than 2% of distribution revenues, we believe the Board should make clear that level is the minimum expected of all distributors. However, there will be cases where it is not realistic to ask the distributor to reach that level in 2006. The onus should be on the distributor to show why that is the case, for example by demonstrating that a Tier 2 catchup program has to be the focus of management energies in 2006 and 2007.

329. ***Variance Account for C&DM Expenditures.*** Various experts have proposed a variance account, under which if C&DM expenditures are below budget they are returned to the ratepayers, and if they are over budget, they can be recovered in rates in subsequent years. This type of system, called a DSMVA in the gas world, is in use for both Enbridge and Union Gas, and has been successful. For the most part, it is used by them to take opportunities that arise during the course of the rate year. For example, if a program turns out to be more successful than expected, the utility can use the DSMVA to add budget to the program and thus increase its value.

330. Two limitations are often put on the DSMVA mechanism, and we recommend that the Board adopt them in this case. First, expenditures can only go over budget by 20% and still be recovered. Second, over budget expenditures must be program-only expenditures (not internal costs), and must be spent on programs that produce a positive net TRC benefit. Sometimes a minimum TRC to cost ratio is stipulated, but given the nature of the SSM we propose, below, we do not believe that is necessary in this case.

16.3 Accounting Principles Applicable to C&DM Expenditures

331. ***Capitalization of Expenditures.*** Operating costs of C&DM programs, such as the internal personnel managing the programs, etc., should, in our view, be expensed in the same manner as most other operating costs. Program costs, however, should in our view be capitalized and added to rate base, then amortized over the useful life of the measure. This reflects an appropriate matching of costs to benefits.

332. Most of the program costs will, however, be deductible for tax purposes. In keeping with normal practice, those deductions should be taken, and the tax savings thus generated will, as with all tax to accounting timing differences, be reflected in lower rates. The 2006 OEB Tax Model should include a calculation to reflect this timing difference.

333. ***Allocation of C&DM Costs to Classes.*** We have in the past expressed a concern that requiring a class to pay a share of the cost of C&DM is in some respects unfair if there are no programs available for that class. However, our conclusion is that there is still a significant benefit to all, and therefore that, until we have more experience in how costs and benefits track through the classes, all C&DM costs (whether distriibution expenses or rate base) should be allocated to all classes.

334. In terms of the nature of the allocation, we believe that C&DM saves both kwhrs. and peak KW, and also reduces long term system costs. All should be reflected in the allocation. We therefore propose that C&DM costs be allocated to classes on the basis of distribution revenues.

335. ***Rate Recovery Methodology.*** We propose that C&DM costs be included in the volumetric charges within classes.

16.4 Revenue Loss and Lost Revenue Adjustment Mechanism (LRAM)

336. ***Forecasting Adjustments in Chapter 9.*** Given the timing of 2006 C&DM Plans this year, it would appear to us to be difficult for many utilities to make timely estimates of the volume impacts of their plans. This will be especially true for any who file C&DM Plans later, as we have proposed. They would have to revise the rest of their application to deal with the volume impacts.

337. To avoid this, we propose that utilities have the option, with respect to the 2006 impacts of their 2005 C&DM Plan, and with respect to the impacts of their 2006 C&DM Plan if it is filed with the rate application, to adjust the 2006 volumes to reflect the anticipated impacts of those Plans. The adjustment should include a full justification for the impacts proposed.

338. Unless a distributor meets those criteria and elects to make the adjustment in their application, they should not be allowed or required to make an adjustment for C&DM

volumes. Lost revenues should instead be dealt with in the LRAM mechanism.

339. ***Incremental Lost Revenues Variance Account.*** The Board heard evidence about various types of lost revenue adjustment mechanism. It is submitted that both gas distributors use an LRAM that has been working well for some time. Rather than reinvent the wheel, we believe that the Board should adopt that same mechanim for the LDCs in 2006.

16.5 Shareholder Incentive

340. ***Principles Applicable to C&DM Incentives.*** It is submitted that it is not appropriate to reward a distributor that produces "insipid results", as Mr. Chernik described it. Yet the proposal put forth by Pollution Probe, and reluctantly supported by Mr. Chernik, rewards exactly that. Under that proposal – a 5% SSM from the first dollar – each distributor gets a budget of ratepayers' money to spend on C&DM, and if any net TRC benefits are generated from that spending (how could there not be?), the distributor is rewarded. It is submitted that this incentive structure sends the wrong message, and wastes ratepayer money rewarding performance that does not require incentives.

341. In fact, it is clear that neither Mr. Gibbons nor Mr. Chernik (nor anyone else, at least not in the hearing room) really supports the Insipid Results SSM. Both Pollution Probe and the Green Energy Coalition, as well as every single ratepayer group, oppose this structure for either Enbridge or Union Gas (both of whom are proposing it now that it has been approved on an interim basis for 2005 electricity C&DM). No-one has led any evidence that shows that this is a preferred structure in other jurisdictions.

342. In fact, the only thing that it appears to have going for it is that it is simple. In our view, simplicity is not a positive attribute if it produces a poor result. In this case, unless simplicity is the sole goal of the Board for an SSM, the Insipid Results SSM has no foundation to be approved.

343. As a matter of principle, we believe that the Board should establish a threshold of minimum performance that all distributors are expected to meet. While there should be no penalties today for failing to meet that threshold, the Board should communicate that in the future distributors that fail to meet minimum C&DM performance standards will, just as would be the case with failure to meet safety or reliability standards, be subject to penalties or other Board action.

344. It is submitted that the Board should, therefore, implement an SSM that rewards only good performance, while ensuring that poor performance is not penalized today, but the prospects of future penalties are known.

345. ***Structure of 2006 Incentive.*** The problem with an SSM that relies on a threshold and only rewards performance above the threshold is that setting the target or pivot point can be a

difficult and contentious task. That is especially true here, where most utilities will not even file on a future test year basis, so will be doing very little forecasting as part of the rate-setting process.

346. It is submitted that a threshold or target is only a problem if it is set in advance, and is fixed. In Ontario, we have a relatively unusual situation in which we have 95 distributors, all with roughly the same responsibilities, although in some cases markedly different service areas. We believe that the Board can use this fact to advantage by setting the threshold based on the actual C&DM performance in 2006 of all LDCs.

347. Specifically, we propose that when the C&DM results from all LDCs across the province are available for 2006, they be compared, and the distributors that have performed the best in C&DM results relative to their peers be given a substantial SSM bonus based on that success.

348. ***Calculation of 2006 Incentive.*** The C&DM results we propose that the Board should compare for purposes of the SSM are the following:

(a) *Total volumes saved as a ratio of base year volumes*. This measure of kwhr reductions resulting from the distributor's programs is the simplest way to determine who has had the best overall success at meeting the province's reduction goals. It adjusts for the size of the utility, and is an easily understood measure. If a utility saves 3% of its volume through C&DM programs in one year, pretty soon everyone will know how well that stacks up to the performance of its peers.

(b) *TRC Benefits as a ratio of C&DM budget spent.* This measures productivity or efficiency. It determines which utilities are getting the biggest bang for the buck.

We have deliberately proposed two measures, rather than one, after listening to suggestions from other parties. By balancing two measures, we avoid encouraging distributors to go after small volume but high leverage programs exclusively, and we avoid encouraging them to seek high volume programs with less significant TRC benefits.

349. Once the Board has the comparison between the distributors' results as above, the median across the province should be calculated for each of the two measures. An SSM equal to 5% of net TRC benefits should be paid to any utility that is above the median in both categories. A further, additional SSM equal to 5% of net TRC benefits should be paid to any utility that is above the median in one category, and is 20% or more above the median in the other category. These are the top performers, and should be rewarded accordingly with an SSM at 10%.

350. We believe that the cost of this SSM is probably similar to that of the Pollution Probe proposal (or maybe a little less), but the higher incentive to the top performers will spur better results, and so the overall benefit to the ratepayers and the province will be increased.

351. ***Incentives in Future Years.*** An SSM of this sort will be more effective if distributors see that it will be in place more than one year. We propose that the Board advise utilities of its intention to retain this structure for three years, so that distributors who do not achieve an SSM in 2006 feel that they can strive to reach that target in 2007 or 2008.

352. We also propose that the Board advise utilities now that, commencing in 2008, it is considering implementing a penalty (perhaps 2%) for utilities that are more than 20% below the median in either of the two categories of measurement. The reason for doing this now is to promote utilities working together to develop common programs. One of the advantages of doing so is that common programs are less likely to have performance well below provincial medians.

353. It is submitted that an SSM structure that rewards top performers, and ultimately penalizes the very poorest performers, is the best way to encourage excellence in C&DM programs. It is a structure that tracks the design of incentive programs for corporate management, and it spends money only where distributors deliver beyond a minimum threshold.

CONCLUSION

The 2006 EDR Process

354. The School Energy Coalition believes that the 2006 EDR Process has been – perhaps surprisingly to many who were involved – a very successful process. While it was true that many initially thought it would be all talk and no action, in fact the opportunity to exchange positions and thinking between distributors and ratepayers proved to be invaluable. Utilities and ratepayers who had not in the past had the opportunity to try to understand each others' views were able to do so.

355. The proof is in the results. Even prior to the issues proceeding in November, more than 90% (by our estimation) of the potential issues for the Handbook were resolved by discussion and consensus. Then, even though the "discussion" part was essentially complete, in fact many of the remaining issues were either agreed or narrowed in scope. What the Board was presented with at the oral hearing is a very short list of disputed issues requiring evidence, and the number of items on which we and other parties are filing submissions is quite limited. Most of the Draft Handbook is, today, presented to the Board by agreement between the parties.

356. We should point out that this is against the backdrop of the size of the task the Board faced in drafting this Handbook. The electricity distribution business is, to say the least, in a period of transition, and the regulation of that business is also in a period of transition. To go from the old Handbook, with very different assumptions and goals, and with limited stakeholder involvement, to a new Handbook that is much closer to a cost of service model, was not a trivial task.

357. The School Energy Coalition believes that the Board's overall strategy of splitting up the transition issues between 2006, 2007 and 2008 is the first reason why this has, so far, been successful. While schools stand to benefit the most, perhaps, from the review of cost allocation and rate design, we accept the additional delay in order to implement what we believe is the correct strategy of updating revenue requirement first, then reviewing cost allocation and rate design, and then completing the process of moving to true cost of service by 2008.

358. But we note that the second important reason why this process has been successful so far has been the intense involvement of Board staff in pushing and managing the process, on the one hand making sure the goals were achieved, but on the other hand staying out of the way and letting the market participants – the distributors and the ratepayers – work things out wherever possible.

359. Finally, it is clear that the distributors and the ratepayer groups have invested considerable

time, resources, and goodwill in this process. Many issues were resolved because distributors accepted the fairness of adjustments that would result in lower rates, while others were resolved because ratepayers accepted rate increases because the underlying causes were fair. The reason the Board sees a Draft Handbook that is largely by consensus is that both distributors and ratepayers sought the fair solution, and limited their adversarial urges.

<u>Future Distribution Rate Adjustment Processes</u>

360. For the reasons above, the School Energy Coalition believes that the model used in the 2006 EDR Process should be considered, with appropriate adjustments and improvements, for use in the 2007 Cost Allocation and Rate Design Review. We believe that many of the potentially contentious issues that may arise in that process can be overcome by using the co-operative and consensus-building approach that made the 2006 EDR Process successful.

<u>Costs</u>

361. The School Energy Coalition hereby requests recovery of its reasonably incurred costs in this process. We note that Bill 100 has now been passed, allowing the awarding of costs in policy processes as well as proceedings. While we understand that the Board's initial decision was to continue with the non-costs funding program originally announced and approved, we invite the Board to reconsider that at this time.

362. It is submitted that the 2006 EDR Process has been more successful than the Board or anyone else expected, in part because of the participation of ratepayer and environmental groups such as the Vulnerable Energy Consumers Coalition, Energy Probe, Green Energy Coalition, Pollution Probe, and the School Energy Coalition (to name just a few). All five of those groups, for example, led expert evidence that assisted the Board in the oral phase of the hearing, and participated actively in the working groups prior to that time. Other groups also participated in the working groups and/or in the oral hearing.

363. Therefore, we believe that this is a circumstance in which it is appropriate for the Board to exercise its newly-broadened powers to award costs, and to respond to the contribution of the intervenor groups, including the School Energy Coalition, by ordering the recovery by them of their reasonably incurred costs.

All of which is respectfully submitted.

Jay Shepherd
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APPENDICES

APPENDIX A

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WITH ADDITIONAL COLUMNS

APPENDIX B

PROPOSAL FOR

PHASE I HARMONIZATION OF

FIXED MONTHLY CHARGES

[Note: At the time this chart was prepared, applications for six of the distributors were not available and so 2004 fixed charges were used. The chart must be updated before completion.]

APPENDIX C

COMPARISON OF ANNUAL DISTRIBUTION CHARGES

PAID BY SCHOOLS IN DIFFERENT FRANCHISE AREAS

[Note: In reviewing these charts, note that no 2005 rate applications have been seen for Eastern Ontario Power, Espanola, or Sioux Lookout.]