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

AND IN THE MATTER OF the preparation of handbook for electricity distribution rat applications.

SUBMISSIONS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

INTRODUCTION

These are the submissions of the London Property Management Association ("LPMA") on the second draft of the electricity distributor rate handbook dated January 10, 2005. As requested, the submissions are structured by chapter and section of the second draft of the handbook.

Due to funding constraints LPMA has not actively participated in the oral hearing and has not provided comments on all aspects of the draft rate handbook, concentrating only on those areas of most concern to it.

SUBMISSIONS

CHAPTER 3 – TEST YEAR AND ADJUSTMENTS

Section 3.0 Test Year and Adjustments

The draft handbook provides two alternatives related to material events that are expected to occur in 2006. LPMA supports Alternative 1, whereby the applicant is obliged to disclose such events in the description of the application. This is because this alternative is symmetrical – that is disclosure of such events may be positive or negative. Alternative 2 is asymmetric in that it allows the applicant to only disclose such events if it wishes. LPMA submits that this could lead to applicants providing biased disclosures. In the interest of fairness to both ratepayers and shareholders, a balanced disclosure should be mandated by the Board.

<u>Section 3.1 Historical Year versus Future Test Year</u>

LPMA notes that the use of an historical test year, along with the limited number of adjustments contemplated in the draft handbook, does not constitute a true cost of service method of regulation. At best it is an attempt to approximate what the revenue requirement will be in a future period without the benefit of incorporating costs from the same period. Given the Board's inability to deal with nearly 100 such applications the proposed methodology is acceptable, but only as an interim measure. The Board is expected to require the distribution utilities to file cost of service evidence for a 2008 rebasing. LPMA suggests that this filing should be a true cost of service filing, including the use of a forward test year by all utilities. This is required especially if the rebased 2008 year (or a subsequent year) is to be used as the for a PBR plan, the base must be as accurate as possible. With mergers and acquisitions, the number of applications should be fewer. The Board may also want to consider the option of staggering the 20087 rebasing applications over a three or four year period. This would allow the Board, Board staff and intervenors to deal with a significant reduction in the number of applications each year. This is similar to proposals that have been advanced by a number of parties at the Natural Gas Forum.

Section 3.1 concludes with a statement that three years of historical data (2002, 2003, and 2004) must be included with the application. Throughout the handbook, there are a number of sections that indicate these three years of data are to be used to arrive at the adjusted figures for 2006 (for example, average use per customer, losses, etc.). LPMA notes that there are at least two instances where this may be problematic. First, there are a number of utilities that are relatively new and were not operation for this full three year period. The Board should indicate that where this is the case, the data to be used should be limited to those years during which the utility was operating for the full year. By eliminating partial years during which a utility was operating, the problem of trying to adjust a portion of a year to an annualized basis with all the inherent problems related to seasonality of consumption (as one example) can be avoided.

The second instance arises with the merger or amalgamation of two or more utilities over the 2002-2004 period. One of the problems that may arise in this case is the lack of comparability of data between the new utility and the old utilities. The Board should review whether or not it believes special reporting requirements are required in this instance.

Section 3.2 Test Year Adjustments

LPMA submits a number of comments on the table on page 18 of the draft handbook.

Adjustments are permitted to rate base for new transformer stations and directly associated assets with an in-service date of 2005. LPMA submits that in addition the actual costs should be used. Given that applications need to be filed by the middle of 2005, actual costs may not be known. LPMA is concerned that utilities that include these types of adjustments may tend to overestimate the costs if actual data is not yet available, thereby increasing rates to ratepayers unnecessarily. LPMA suggest two approaches that the Board could use to resolve this. The first is the use of a variance account to track the difference between the actual cost impact and the estimated impact. This calculation can be complex since the difference in the capital expenditure impacts rate base, which in turn can impact the dollar value associated with the return on equity and the cost of debt (through the deemed capital structure), income taxes (through the CCA) and capital taxes, as well as the depreciation expense. The second approach, which LPMA recommends, is to require all the utilities that use tier 1 adjustments to update these adjustments as soon as the actual information becomes available in 2005. This adjustment would be a simple change in the spreadsheet model and could be done quickly and easily. This would protect ratepayers from over-estimates and from projects that were expected to proceed in 2005, but for some reason did not.

The preceding comments in the above paragraph also apply to the allowed adjustment to rate base for the actual costs related to wholesale meters.

Also under the rate base section in the table, there are the alternatives to deal with new transformer stations and directly associated assets with an in-service date of 2006. LPMA submits that the Board should accept Alternative 2 and exclude these adjustments. The rationale for this is as follows:

i) because this adjustment is for a year further out from the present, there is more uncertainty related to the project proceeding in 2006 as compared to a project in 2005; and

ii) the magnitude of the difference in the actual cost incurred in 2006 may be greater than any difference that may occur in 2005 because of the longer time horizon.

The impact on rate base is likely to be small, given the proposal to use the half-rate rule (see end of table on page 18). If, however, the impact is significant, and of significant importance to the utility, then that utility should opt for the forward test year and provide detailed evidence to justify the inclusion of such a cost in rate base.

LPMA notes that the purpose of using a historical year for rate making purposes is to simplify the process and eliminate controversial adjustments. Adjusting for new transformer stations with an in service date in 2005 and using actual costs (including updating if necessary) does not add to the complexity of the process or add controversy to the adjustments. However, forecasting adjustments for 2006 does. Forecast adjustments of a major amount should be left to the realm of a forward test year. To do so otherwise defeats the purpose of an historical test year.

LPMA also notes that it is unclear how the impact on rate base for the addition of items such as wholesale meters and new transformer stations is to be calculated. Page 17 of the draft handbook states that Tier 1 adjustments are to be made to the relevant year-end balances (i.e. distribution expense, rate base, or revenue). LPMA suggests that a clear reference to depreciation associated with the Tier 1 adjustments should be included. In particular, accumulated depreciation should be estimated on a 2006 basis for ant Tier 1 adjustments made to gross assets. The following simple example reflects the need for this.

Consider the Tier 1 adjustment to add $100 for wholesale meters that are put in service in 2005. Assume also that the depreciation rate for this class of assets is 5%. At the end of 2005, the net impact on rate base would be $95 ($100 - $5 of accumulated depreciation). At the end of 2006, the impact on rate base is $90 ($100 - $10 for two years of accumulated depreciation). LPMA submits it is the $90 that should be added tpo rate base, not the $100. Also note that his example uses year-end figures for rate base, for simplicity. Elsewhere in this submission LPMA, in fact, supports using the average for the year as the methodology for calculating rate base.

With respect to the low voltage/wheeling adjustments, LPMA submits that if these costs are flow-through items, then the do not need to be dealt with as part of the rates handbook. LPMA believes that it would be problematic to deal with these costs if they form part of the base distribution rates as a forecast would be required. Not only would this deviate from the rationale for using an historical period, it involves utilizes guessing what rates would be approved by the Board for these services. LPMA, therefore, submits that Alternative 2 is appropriate.

Under the heading "New Transformer Stations" on page 20 of the draft handbook, it states that if the applicant "*anticipates*" that any new transformer stations … . LPMA believes that the wording should be stronger and more specific. In particular, "*anticipates*" should be replaced by "*knows*". LPMA again re-iterates that any adjustment for 2005 should be based on actual costs.

At the top of page 22 of the draft handbook, Board staff notes the inconsistency between chapters 3 and 6 with respect to the treatment of unusual bad debt expense in 2004. LPMA supports dealing with a material unusual bad debt expense in 2004 as described in chapter 3 as this clearly falls into the category of a non-routine adjustment for 2004. If such a bad debt met the materiality criteria, it would be a mandatory Tier 1 adjustment. Under the proposal in chapter 6, the adjustment is not mandatory and defeats the purpose as stated in the draft handbook on page 17 that Tier 1 adjustments are to move the 2004 rear figures closer to a "typical" year of capital investments, operations, and revenues through the use of non-routine unusual adjustments, applying to 2004 only.

On page 22 the draft handbook states that mergers and acquisitions taking place after 2004 are to be dealt with outside of the 2006 rate-setting process and are not discussed in the 2006 handbook. LPMA submits that for mergers and acquisitions that take place in 2004, special provisions should also be used. Expected reductions in operating costs and efficiency gains resulting from a merger or acquisition should be reflected in a lower revenue requirement for 2006. It would be unfair to ratepayers if the 2004 actual results for two or more utilities are used to determine rates. Any efficiency gains and\or cost reductions would flow to the shareholder and would violate the goal of cost of service regulation. The Board may wish to consider requiring such utilities to file a forward test year filing in these circumstances.

Turning to the Tier 2 adjustments, the draft handbook (on page 23) states that utilities must provide details on the activities that will be undertaken if the proposed incremental spending is approved, including specific details as to the nature of the envisaged activities and their timing on a monthly basis. LPMA submits that the Board also needs to deal with a number of specific issues related to these expenditures. For example, not all of the expenditures (operating and\or capital) may be required in 2006, but could be spread over a multi-year period. In such a case, not all of those expenditures should be built into 2006 rates. On the other hand, if all the expenditures take place in 2006, some of which are non-recurring, the if the 2006 rates are unchanged for 2007 and/or subsequent years, the utility will be recovering non-existent costs in those years. LPMA recommends that the Board treat the increase in costs related to Tier 2 adjustments through a rate rider rather than as part of base distribution rates. This allows the Board to apply the rate rider for a distinct period of time independent of when base distribution rates are reset. LPMA also urges the Board to require utilities that apply for Tier 2 adjustments to use a variance account to track differences in 2006 between actual expenditures and those proposed as Tier 2 adjustments on a forecast basis.

LPMA supports the adoption of Alternative 1 on page 23. Part of the responsibility of the utility and its owner is to maintain a safe and reliable system. If the system has suffered material degradation, it is the owner’s responsibility to fix the system. If revenues are insufficient to cover these costs, the utility should finance these costs through increased borrowing or an injection of equity from the shareholder. Both of the last two options have been available to utilities over the period in question.

The Board should also ensue that any utility that applies for any Tier 2 adjustments did not pay down the principal on shareholder debt or reduce its amount of equity (including paying any dividends to its shareholder). If any utility did do this, their request for a Tier 2 adjustment should be denied. The utility should have considered the prudence of paying amounts to its shareholder instead of re-investing those dollars into its distribution system and creating the hardship.

At the bottom of page 24, the handbook indicates that if an applicant departs materially from its Tier 2 proposals, The Board will establish deferral accounts, including interest. LPMA submits that this is problematic, since by the time the Board is made aware of the deviation, much of the deviation could have taken place. Will the Board be able to set up these deferral accounts on a retroactive basis? This would seem to go against the Board/s policy in approving retroactive deferral or variance accounts. LPMA also submits that the reference to “deferral accounts” in this paragraph should be replaced with the more accurate “variance accounts”. As noted above LPMA recommends the automatic establishment of variance accounts for all utilities that are granted Tier 2 adjustments.

<u>Schedule 3.1: Tier 1 Adjustments</u>

LPMA submits that Alternative 2 on page 26 be accepted. As discussed previously, there is too much uncertainty regarding the timing of the associated assets in 2006 and in the costs for these assets. If a utility feels strongly that these assets should be included, they have the option of doing a forward test year filing.

<u>Schedule 3.2: Tier 1 Non-routine/unusual Adjustments</u>

The draft handbook states that "If the applicant is not making any such adjustments, a statement to that effect should be incorporated into the description of the application." Given that Tier 1 adjustments are mandatory, the statement should be "If the applicant does not have any such adjustments, a statement to that effect should be incorporated into the description of the application."

<u>Schedule 3.3: Tier 2 Adjustments</u>

AS previously indicated, LPMA submits that the establishment of a variance account to track differences between the forecasted Tier 2 expenditures and the actual expenditures should be done automatically for all utilities that are granted Tier 2 adjustments.

As indicated previously, Alternative 1 should be approved by the Board.

<u>CHAPTER 4 – RATE BASE</u>

<u>Section 4.1 Definition of Rate Base</u>

LPMA submits that the level of detail should be the same as the level of detail for rate base, as shown in Table B.1` in Appendix B. The level of detail shown in Schedule 4.1 is not adequate for a number of purposes, including the calculation of rate base, the calculation of depreciation, the calculation of capital cost allowance, etc. Further if the various rate base/capital expenditure categories are treated differently for cost allocation purposes in 2007, this level of detail will be required. The level of detail should be available and presented in the level described and prescribed in the uniform system of accounts. LPMA therefore submits that Alternative 2 should be adopted by the Board, with a level of detail equal to the uniform system of accounts.

With respect to the definition of rate base, LPMA strongly submits that Board mandate the use of Alternative 2 (calculated as an average of the balances at the beginning and the end of 2004). LPMA is a strong supporter of using the method9ology employed by the gas utilities in Ontario, i.e. the average of the monthly averages. However many electric utilities indicated they did not have monthly financial data that could be used for this calculation. This should cause great concern over the quality of the financial reporting at these utilities for all parties. This is an area where the Board should direct and assist all utilities so they have accurate monthly financial statements and reporting for the 2008 rebasing. In the meantime, using the average of the opening and closing balances in 2004 is much preferable tp using the year-end balance. Using the year-end balance causes two problems. Growing utilities (i.e. those with capital expenditures in excess of depreciation) will over-estimate their rate base and declining utilities (i.e. those with capital expenditures less than depreciation) will under-estimate their rate base.

Rate base calculations play a significant part in the calculation of the revenue requirement. For example, the deemed capital structure and the associated return on equity and cost of debt are all applied to the rate base calculation. If the year-end figure for rate base is used, the overall cost of capital will be inflated. The shareholder will, in fact, be recovering in rates a phantom return on equity for a full year and a phantom cost of debt for a full year on a level of equity and debt that only exist for a portion of the year.

LPMA submits that the Board has a well established and long running methodology of calculating rate base. This involves the average of monthly averages. In the absence of this monthly data, the average of the opening and closing balances is a more accurate proxy than a year-end figure. LPMA notes that in discussing this issue in the working group a number of utilities purported to support the year-end approach because it was simpler. To that LPMA suggests that if adding two numbers and dividing by two is considered to be much more complex methodology then the utilities should be encouraged to invest in computer equipment and training for its staff.

The definition in the rate handbook then goes on to indicate that in addition to net fixed assets, an allowance for working capital is added. The working capital allowance is then described as 15% of the cost of power and controllable expenses. LPMA does not agree with this definition and this is dealt with in Chapter 5. LPMA recommends removing the definition of the working capital allowance from this section as it is defined later in the handbook. Alternatively, Section 5.4 of the handbook, which deals with the calculation of the working capital allowance, should be moved to Chapter 4, since it is a rate base item.

Section 4.2 Amortization Rates

The handbook states that "The amortization study which supports these schedules should also be filed". LPMA submits that "should" should be "must". The Board must approve any change in amortization rates, or any rates that do not match those in Appendix C of the handbook. In order to approve such a rate, evidence that supports it must be filed.

Section 4.3.1 Non-IT-related

LPMA supports Alternative 1. This is more in line with the evidence filed by the gas utilities in Ontario. The two large gas utilities provide evidence on capital expenditures in excess of $500,000. Both of these utilities have a rate base in excess of $1 billion. A third gas utility, with a rate base of less than $10 million was directed by the Board to file its cost benefit analyses for all capital projects with an estimated cost of $15,000 or more (E.,B.R.O. 499 Decision With Reasons, December 30, 1994). LPMA notes that the dollar threshold for the group of small utilities is $75,000, which is 5 times the $15,000 threshold noted above. Under Alternative 2, the threshold for a small utility could rise to $200,000 and for a large utility would be in excess of $2.0 million. LPMA submits that these thresholds are too high.

LPMA also notes that in Section 4.3.2 IT-related, the draft handbook does not have any alternatives for the threshold. In fact, Alternative 1 is used for IT-related expenditures. LPMA sees no reason to have different thresholds for IT and non-IT capital expenditures.

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

LPMA assumes that this section also includes interest paid on variance accounts, but this should be explicitly stated.

With respect to the interest rate to be used for deferral (and variance) accounts, LPMA submits that Alternative 2 should be accepted by the Board. This would put the electric utilities on the same footing as the gas distributors. The Board requires all of the gas utilities to use the approved short-term cost of debt on balances in deferral and variance accounts.

However, in this process the Board will not be approving a short term debt rate for cost of capital. LPMA proposes that the Board approve a short-term debt rate for use in deferral and variance account calculations that is equal to the prime commercial rate plus a fixed number of basis points depending on the size of the utility, as illustrated in the following table (the table uses a prime commercial rate of 4.25% for illustrative purposes). The basis points would be 150 for the group of small utilities. This reflects the Board's findings for the short-term debt for Natural Resource Gas Limited, a small natural gas distributor in the province, for a number of years.

Utility Size	Rate Base	Prime Commercial Rate	Differential	Short-Term Debt Rate
Large	> $1.0 billion	4.25	1.05	5.30
Medium-Large	$250 million - $1.0 billion	4.25	1.15	5.40
Medium – Small	$100 million - $250 million	4.25	1.25	5.50
Small	< $100 million	4.25	1.50	5.75

The decrease in the differential for the larger utilities is based on the relative differential in Table 5.1 of the draft handbook.

Some parties have raised the issue of whether longer term debt rates should be used on these accounts because historically they tend to be longer in horizon than 1 year. LPMA submits, however, that it expects the Board will deal with deferral and variance accounts on a regular basis, at least annually. As a result a short-term debt rate is appropriate.

In addition to the above, LPMA submits that the prime interest rate used in the calculation of the short-term debt rate be adjusted to reflect the actual prime commercial rate in effect at the beginning of each calendar quarter. By allowing the short-term debt rate to change every three months to reflect the actual prime rate, both utilities and ratepayers are protected from paying rates that are out of date. This ensures that interest costs are closer to actual costs for all parties. This is important when deferral and variance accounts can have debits or credits and when interest rates may rise or fall between the current time and when the Board would re-set them.

With respect to the interest rate to be used for construction work in progress, LPMA supports Alternative 1, but that the interest rate should be the <u>**deemed**</u> embedded cost of debt. Since construction work in progress usually involves assets of long life that ultimately are included in rate base, the use of the deemed embedded cost of debt is more appropriate than a short-term debt rate.

<u>Section 4.5 Capitalization Policy</u>

As part of the rebasing for 2008, it would be useful for parties, including the Board, to be able to compare capitalization policies for various utilities. LPMA, therefore, recommends that the Board accept Alternative 2. This would enable parties to make comparisons to see if it would be possible or even desirable, to move to a standard capitalization policy across utilities.

<u>Section 4.7.1 Non-depreciable Assets Sold to a Non-Affiliate</u>

A statement should be added to this paragraph that indicates that utilities are obligated to inform the Board and intervenors of any such gain or loss immediately. Given that these gains or losses may occur after rates have been established, a variance account should be established to record the actual gain or loss.

<u>Section 4.7.2 Depreciable Assets Not Sold to an Affiliate</u>

For consistency, this section should be titled “Depreciable Assets Sold to a Non-Affiliate.

<u>CHAPTER 5 - COST OF CAPITAL</u>

<u>Section 5.1 Maximum Return on Equity</u>

LPMA submits that Alternative 1 should be adopted by the Board. Alternative 1 presents a simple methodology. However, it may be useful for the Board to update the interest rates at the end of December, 2005. This would require the utilities to update their filings for the long Canada bond rate. However Alternative 2 goes further than this and allows a new return on equity to be set annually. In the absence of a cost of service filing for 2007, allowing the return on equity to be adjusted, but not allowing for changes to other components of the revenue requirement, such as OM&A, rate base, depreciation, taxes and revenue growth, would be unfair and unbalanced. As a result LPMA opposes an annual change in the return on equity as proposed in Alternative 2. LPMA also opposes the use of a variance account to track any differences that may result if Alternative 2 is accepted by the Board. This will introduce inter-generational inequities into subsequent rates.

<u>Section 5.2 Debt Rate</u>

With respect to the calculation of the weighted average debt rate, LPMA supports the adoption of Alternative 2. The two alternatives appear to be identical except that the debt rate for a loan from an affiliate is determined by the deemed rate at the time of issuance by the affiliate in Alternative 2. LPMA submits that this is fair. Long term debt costs should not be subject to revision. If they were prudent when the deal was signed, they should be acceptable at the current time. Otherwise, why would a utility want long term debt that carried a regulatory risk of not being able to recover the actual cost of that debt?

<u>Section 5.4.1 Working Capital Allowance</u>

Alternative 4 should be accepted as it provides the most consistency in the model. None of the other alternatives make an adjustment to reflect kW and kWh changes that are in other parts of the model. Alternatives that rely on a forecast of the cost of power should be avoided as this gets the process dangerously close to a forward test year process that requires greater scrutiny of the evidence.

LPMA also strongly submits that an additional adjustment needs to be made to the working capital allowance. At the bottom of page 44 of the draft handbook, two additional adjustments are proposed. LPMA supports the need to adjust the working capital allowance for customer deposits. However, LPMA does not support alternative 1 as stated since the customer deposits are multiplied by the 15% allowance.

LPMA supports the inclusion of the full amount of the customer deposits as a reduction in the working capital allowance calculation component of rate base. The use of the 15% allowance was designed to represent approximately 2 months of cost of power and 1.5 months of controllable expenses (sum of operations and maintenance, billing and collection, and administration), as stated in Section 3.4.1.1 March 9, Electricity Distribution Rate Handbook. LPMA submits that customer deposits are a source of working capital, just as they are for regulated natural gas utilities in Ontario. The Board has a long standing practice of including customer deposits in the calculation of rate base for natural gas utilities. A review of any of the Board's rate Decisions, and, indeed, the evidence of the three regulated gas utilities filed over the last decade or more, shows this. LPMA submits that electricity ratepayers should receive the same treatment as natural gas ratepayers. A conservative estimate of the total amount of customer deposits held by electric utilities across the province would be in the tens of millions of dollars. The reduction in the collective rate base of the utilities across the province, when multiplied by the deemed overall cost of capital, would amount to millions of dollars in reduced revenue requirements.

CHAPTER 6 – DISTRIBUTION EXPENSES

Section 6.0 Level of Detail

LPMA supports the adoption of Alternative 1. Distribution expense data should be provided at the level of detail found in the Uniform System of Accounts. LPMA does object to the aggregation of these costs into groups, but the underlying detail should be provided in the filings. There are two reasons for this. First, utilities may group their costs differently, making it difficult to compare these costs across similar utilities. Utilities may also classify their costs in the detailed differently from one another. Without the detailed information, these inconsistencies would not be identifiable. Secondly, the provision of the information at the same level of detail as in the Uniform System of Accounts will provide the maximum flexibility in the use of this data for cost allocation purposes, scheduled for 2007. If only grouped data is provided, these groups may not correspond to the allocation of categories of costs. It would also, in LPMA's submission, have the potential to bias the cost allocation process by grouping data for distribution expenses.

<u>Section 6.1.1 Non-distribution adjustments</u>

As indicated above, LPMA recommends the filing of distribution expenses at a level of detail consistent with the Uniform System of Accounts.

<u>Section 6.2.2 Bad Debt Expense</u>

Bad debt expense is dealt with in Chapter 3. If a bad debt expense qualifies as a non-routine or unusual adjustment (i.e. meets the threshold) then it must be adjusted accordingly.

The proposal, as contemplated in Chapter 6, to allow full or partial recovery of an unusual bad debt, does not make sense given that the goal of this process is to establish a "normal" year based on 2004 actual data for revenue requirement purposes. LPMA recommends removal of Section 6.2.2 from the handbook.

<u>Section 6.2.4 Advertising, Political Contributions, Employee Dues, Charitable Donations, Meals/Travel and Business Entertainment, Reasearch and Deveopment</u>

LPMA agrees with recommendations in the handbook related to advertising expenses, political contributions, employee dues, and research and development.

With regards to charitable donations, LPMA supports Alternative 2. No charitable contributions should be included in the determination of the revenue requirement. This would be consistent with the regulation of the natural gas distributors in Ontario. Again, electricity ratepayers should not be burdened with costs that natural gas ratepayers do not have.

Electric utilities, the majority of whom are owned by local municipalities, may face pressure from their owners to donate to local charities. This would reduce the need for the municipalities to provide funding through the property tax system. For example a municipality could provide a $100 grant with this amount collected from property taxes. Alternatively, the municipally owned utility could provide the $100. The after-tax portion of this (approximately $65) would be paid for by the distributors ratepayers. The remaining cost (approximately $35) would be funded by lower PILS payments to the OEFC, ultimately costing all electric ratepayers in the province. As a result ratepayers in London could end up paying more through the debt retirement charge for donations made to local charitable organizations in Toronto, Hamilton, Ottawa, and so on. LPMA submits that this perverse outcome should not be allowed to occur.

LPMA also notes that it is unfair to require ratepayers to fund charitable donations and not get tax deductions for doing so. Ratepayers should be allowed the privilege to donate to the organizations that they choose to support and receive the tax benefits of doing so. LPMA supports electric utilities, and by extension, their shareholders, making charitable donations. However this should be a corporate or shareholder expense, not a ratepayer expense.

Turning to the issue of meals/travel and business entertainment expenses, LPMA supports the adoption of Alternative 1. A mandatory filing (and review) of the employer's policy is prudent given the publicity related to limousines and yachts. Failure of the Board to require the filing and review of these policies would leave the Board open to criticism should some yacht-like expense come to light in the future. The Board may lose credibility with the public (and by extension with the government) if it fails to address this issue now.

Some utilities may not have a written policy related to these expenses. LPMA strongly urges the Board to require any such utilities to develop and file their written policy as part of their process.

<u>Section 6.2.5 Employee Total Compensation</u>

LPMA supports Alternative 1 for applicants with fewer than three employees.

LPMA supports Alternative 1 under additional filing requirements. That is the total compensation for each distributor employee earning more than $100,000 per annum must be reported separately. Names of employees, however, need not be reported. The job title of each employee should be reported. The Board may also want to consider reporting the number of employees earning more than $100,000 per annum in total compensation, without names or job titles, in ranges, such as $100,000 to $150,000, $150,000 to $200,000, etc.

Turning to the issue of incentive plans, LPMA submits that these none of costs should be included in the 2006 revenue requirement for the reasons set out below.

First, any incentive plan costs that provide benefits to the shareholder and not to the ratepayers should not be recoverable from customers. Costs should follow the benefits. If the benefits flow to the shareholder, so should the costs.

Second, any incentive costs that benefit ratepayers, would in a normal regulatory process, be paid for by those ratepayers. However, the use of a historical test year raises the issue of when the customers would realize those benefits. For example, incentive payments may have been made to employees for reducing utility costs. LPMA supports recovering those incentive payments from customers since they will benefit from the reduced costs in the future. However, it is likely that these reduced costs are not fully reflected in the historical 2004 costs as any cost saving measures would not be in place for the full year. As a result, ratepayers will not see the full reduction, or benefit, in their 2006 rates. By excluding the incentive payment costs as a proxy for the benefits that customers should receive, customers would at least receive a portion of the benefits that are supposed to be accruing to them. This assumes that the benefits exceed the cost of the incentive payments associated with the benefits to ratepayers. If this is not the case, then the incentive payments were too high and should be allowed to be recovered in future rates.

Section 6.2.7 Distribution Expenses Paid to Affiliates

LPMA supports Alternative 1. When affiliates are involved, the onus is on the applicant to prove that the costs it wants to recover from its customers are reasonable and prudent. The Board has had significant experience in this issue with the regulated gas utilities over the past number of years. Based on this experience, The Board knows of the importance of this issue to ratepayers.

Schedule 6-1 Employee Incentive Plan Expense

LPMA submits that the minimum filing requirements shown in Schedule 6-1 should be required. It is up to the applicant to justify the inclusion of incentive plan costs as an expense to be recovered from ratepayers. If an applicant fails to provide this schedule and any other evidence needed to justify such expenses, if allowed by the Board, then that utility has forfeited their right to recover these costs in their revenue requirement. The onus is on the applicant to justify recovery of any such expense.

Schedule 6-2 Non-OMERS Pension Expense

In answer to the question posed, LPMA replies yes. There is no reason to not supply the same three years of historical data as for over expenditures required elsewhere in the draft handbook.

Schedule 6-3 (a) Distribution Expenses Paid to Affiliate(s)

Under Question 1, it is stated that a description of the "general" methodology used be provided. LPMA submits that "general" should be replaced by "specific".

With respect to Question 2, the onus is on the applicant to justify using a cost-based price in the absence of a market for the service. The first step in the justification is establishing on the record the absence of such a market. Without this first step, any cost-based price cannot be accepted.

Turning to Question 3, LPMA submits that a price cannot be determined to be cost-based unless and until the actual costs and the allocation of those costs from the affiliate are known. To say or do otherwise would make a mockery of the whole concept of cost-based pricing.

<u>Schedule 6-3 (b) Distribution Expenses Incurred Through Sharing Services with Affiliate(s)</u>

LPMA submits, that similar to the requirements that came out of the regulatory assets proceeding, the general manager should provides a signed and sworn document that provides an explanation of how they have followed, and are complying with, the transfer pricing and shared services rules in the Affiliate Relationships Code. In the absence of such a confirmation, such costs should not be allowed by the Board.

<u>CHAPTER 7 – TAXES / PILS</u>

<u>Section 7.1 Rules and Principles</u>

In the second sentence in this section it is stated that rebasing will be <u>***allowed in***</u> 2008. This statement is incorrect. It should read that rebasing will be <u>***required for***</u> 2008. It was agreed that rebasing was required for the 2008 rates year to address a number of issues throughout the draft handbook. Also, the rebasing is for the 2008 year, not in the 2008 year.

No mention has been made in the Taxes/PILS chapter regarding not-for-profit distributors. The model being developed should have an option for not-for-profit utilities so that they can automatically bypass the taxes sub-model.

Section 7.1.1 General Principles Underlying the 2006 Tax Calculation

The first paragraph under this section should acknowledge that some Ontario distributors are not-for-profit corporations and do not pay income and capital taxes.

Another section should be added to the General Principles related to the stand-alone principle. As indicated in Ms McShane's evidence on behalf of The Coalition of Issue Three Distributors, (Exhibit B.9), the stand-alone principle is a cornerstone of Canadian utility regulation. Adherence to this principle means that only the costs, risks and benefits that arise from the provision of regulated service are borne by ratepayers. In particular, LPMA submits that the following be added to Section 7.1.1 under the heading 'Stand-Alone Principle':

> "The application of the stand-alone principle is designed to remove the effects of diversification by utilities into non-regulated activities. A utility is regulated as if the provision of the regulated service were the only activity in which the company is engaged. This application of the principle ensures that the revenue requirement of regulated utility operations is not influenced up or down by the operations of a parent or other affiliate company. The cost (or revenue requirement) of providing utility service reflects only the expenses, capital costs, risks and required returns associated with the provisions of the regulated service."

The above is a paraphrase from EUB Decision 2001-92, December 12, 2001, pp. 24-25 that is referenced in Exhibit B.9.

Prudent Management of Taxes

Under the prudent management of taxes heading, the wording should be changed to "All distributors are ***"required"*** and expected to take prudent steps to manage their tax costs with reasonable diligence, as they would with other distribution expenses".

<u>True-Up of 2006 Actual Taxes Paid to Taxes Recovered in Rates</u>

Two alternatives are presented in this section. LPMA submits that Alternative is reasonable. The key component of Alternative 1 is that revenue and expenses included in regulatory income before interest and taxes will not be subject to a true-up. A true-up will only take place for changes to the tax rates or rules, assessing or administrative policy changes of tax authorities and re-assessments received by a distributor after is 2006 rate application is filed and before May 1, 2007 that relate to ant tax year ending prior to May, 2006. LPMA submits that a true-up for ant of these variances is appropriate given the limited time that most utilities have been subject tp PILS and the fact that that the rules may change. This provides a fair balance to both the distributor and their customers.

LPMA opposes Alternative 2 because it produces perverse results that would de-stabilize rates. This can be seen in the following example. If a utility earns in excess of what is built into rates because of higher revenues (due to weather, for example) and\or lower expenses, then their actual tax payable will be higher than that recovered through rates. Alternative 2 would result in ratepayers being told they have to pay higher rates because their distributor made too much money. Talk about a public relations nightmare and loss of credibility for the OEB and all parties that approved such a nonsensical result! Such a result may also call into question the whole methodology of a historical test year used to determine rates for a future period.

Similarly, if the utility had lower taxable income as a result of lower revenues (due to weather, for example) and\or higher than expected expenses, the amount of tax actually paid would be lower than that recovered in rates. In this case, can you imagine the surprise on the face of the shareholder as the utility executive explains to them that because they made less money than they expected, they now have to take a further hit and give money back to their customers!

The net result is that if the utility under-earns, rates would need to be reduced to reflect the tax refund to customers and if the utility over-earns, rates would have to increase to reflect the additional cost to ratepayers. In both cases, the changes increase rate instability.

Alternative 2 also fails to acknowledge that variances in taxes due to variances in the components of taxable income are a normal part of business risk that all businesses face. This risk is part of the implied equity risk premium of 3.80% used in Chapter 5. If the utility transfers the tax risk to ratepayers, then there needs to be a substantial reduction in this implied equity risk premium. Since the Board has already determined that the implied equity risk premium will not be reviewed until the 2008 rates year, LPMA submits that it should not accept an alternative that would reduce the utility risk, but not reflect that in rates.

<u>Section 7.1.2.1 Regulatory Assets and Liabilities</u>

The handbook states that all regulatory asset recoveries that are included in projected 2006 net income shall be deducted on a specified line of the 2006 OEB tax model. LPMA does not understand why any recover of a regulatory asset or liability – which are balance sheet items – would show up on a net income line.

<u>Section 7.1.2.2 Non-recoverable and disallowed expenses</u>

An issue in this process is whether or not tax savings that result from non-recoverable and disallowed expenses should flow to the shareholder, the ratepayer, or be shared between the two. LPMA has based its submission on the four key underpinning principles and government objectives to be resolved put forward by Ms. McShane in Exhibit B.9. These four principles and objectives are;

i. benefits follow costs,
ii. the “stand-alone” utility,
iii. a level playing field, and
iv. “no harm” to ratepayers.

LPMA supports these principles and objectives and submits that the Board should use them as the basis for their determination of this issue.

Ms. McShane has presented compelling evidence that any such tax savings should flow to the shareholder. LPMA agrees with Ms. McShane that in a normal regulatory environment this would be the case. If a cost is not recovered from the ratepayers then any tax savings should not flow to the ratepayers. Ms. McShane calls this her "benefits follow costs" principle. In the gas industry in Ontario, this is the process that is followed. The costs of disallowed and non-recoverable costs are borne by the shareholder and are partially mitigated by the tax savings to the shareholder. There are no costs to ratepayers and ratepayers do not benefit from the tax savings.

The question is whether or not the environment in Ontario can be considered normal. LPMA submits that it is not. The Board has heard testimony that the PILS regime in Ontario is unique. PILS paid by utilities in Ontario are used to pay down the same debt as revenues collected through the debt retirement charge. The system is essentially closed. If PILS payments are lower, the debt retirement charge will be higher or in existence for a longer period of time.

LPMA submits that this means there are costs to ratepayers associated with tax savings for non-recoverable and disallowed expenses. The tax savings thus generated result in higher or longer payments of the debt retirement charge by the very same ratepayers. And, in fact, the problem is exacerbated. This is because the tax savings associated with non-recoverable and disallowed expenses from one utility are paid for by all ratepayers across the province. For example, if Toronto Hydro makes substantial political contributions or pays significant bonuses to it employees that the Board determines are not recoverable from its ratepayers, then the tax savings to Toronto Hydro become a cost to the ratepayers of London Hydro and every other utility in Ontario, not just those of Toronto Hydro.

As Ms. McShane states in her evidence, the "benefits follow costs" principle holds that the stakeholder who has borne the costs should receive the benefits. If a stakeholder incurs the costs, he should be entitled to any related tax savings.

An example of the various proposals raised in oral testimony with Dr. Mintz was the $100,000 charitable donation that ultimately cost the shareholder $65,000 by reducing his taxes by $35,000. Under the alternative that ratepayers do not get this tax reduction in their revenue requirement the “benefits follow costs” principle is violated. The $35,000 tax savings to the utility is a cost that is borne by ratepayers. But no benefits have followed these costs to the ratepayers.

The conversation between Dr. Mintz and Mr. Kaiser (Tr. Vol. 1, pp 1222 – 1252) highlights what will happen if the PILS reduction associated with the non-recoverable or disallowed expense is allocated to the ratepayers. In this case, the benefits do follow the costs. As Mr. Kaiser stated and Dr. Mintz agreed, the rates go down and the payment term is longer and that the ratepayer is neutral (Tr. Vol. 1, pp 1240 – 1243). The key premise of Mr. Kaiser’s statements is that the PILS is a regulatory expense and it follows that the reduction in PILS is a reduction in the regulatory expense to be paid by ratepayers. This is clearly Alternative 2, 100% of the tax savings go to ratepayers.

Ms. McShane’s second principle is the stand-alone principle. It holds that only those costs and risks that pertain to the activities of the regulated utility in respect of the provision of service to ratepayers are reflected in the revenue requirement. This principle should be applied to the income tax component of the revenue requirement.

In a normal regulatory environment the only entity that affects the rates paid by ratepayers is the regulated entity. However, In Ontario, as explained above, non-regulated entities also impact the rates paid by ratepayers through the PILS and the tax deductions available to the non-regulated entity.

Ms. McShane states in her evidence (Exhibit B.9, page 6 of 31), that as a consequence of the stand-alone principle, costs that are incurred by the legal entity, but are not borne by customers, are, for ratemaking purposes, appropriately defined as non-utility costs. As indicated above, however, the reduction in PILS associated with these non-utility costs are, in fact, borne by customers through higher and/or longer debt retirement charges.

The third principle is the Government's stated objective to create a level playing field through the Payments in Lieu of Taxes ("PILS") which requires that the income tax allowance for electric utilities that are subject to PILS be determined in a manner equivalent to that applicable to taxable utilities.

LPMA submits that net result of the PILS system does not create a level playing field unless the tax benefits of non-recoverable and disallowed expenses goes to the benefit of ratepayers. This is because the tax reductions for non-recoverable and disallowed expenses for electric utilities that are subject to normal federal and provincial income and capital taxes do NOT impact on the level of debt held by the OEFC. Tax reductions for non-recoverable and disallowed expenses for electric utilities that are subject to PILS DO impact the level of debt held by the OEFC. As a result, as far as ratepayers are concerned, there is not a level playing field in terms of the impact on their rates now and in the future.

Ms. McShane's forth and final principle is the "no harm" principle. This principle states that a condition for approval is "no harm to ratepayers". Clearly this principle is violated. The higher the non-recoverable and disallowed expenses are, the greater the reduction in PILS and the higher the debt will remain. Since ratepayers ultimately have to pay for this debt, they are harmed.

For all of the above reasons, LPMA submits that Alternative 2 should be adopted by the Board and 100% of the tax savings associated with non-recoverable and disallowed expenses be allocated to ratepayers. If the Board were to determine that based on regulatory principles that it should not allocate 100% of the tax savings associated with non-recoverable and disallowed expenses to ratepayers, LPMA submits that the Board advise the appropriate government ministries of the negative impacts on ratepayers and the level of debt held by the OEFC.

<u>Eligible Capital Expenses (ECE)</u>
<u>ECE with respect to disallowed expense</u>
<u>Charitable Donations</u>

LPMA supports the adoption of Alternative 2 for each of these sections the same reasons given in the above section. The reduction in PILS should be allocated to ratepayers otherwise there is an increase in the debt burden of ratepayers caused by the actions of the PILS paying utilities.

With respect to the fair market value, Ms. McShane stated that she had determined that there were no costs associated with the bump that are included in the stand-alone utility for revenue requirement purposes (Tr. Vol. 5, pp 94). This may be correct, but there are costs to ratepayers directly resulting from this fair market bump. The lower resulting PILS payments mean more debt to be paid for by ratepayers through the debt retirement charge. It would be difficult to conclude that the government meant for ratepayers to end up paying more through their actions to allow greater deductions for PILS purposes.

<u>Section 7.1.2.4 Sharing of tax exemptions</u>

LPMA disagrees with this entire section. It violates the stand-alone principle, which according to Ms. McShane, a witness for a coalition of a large number of electric utilities, is a "cornerstone of Canadian utility regulation" (Exhibit B.9, page 6 of 31). Her evidence goes on to state that:

> "the stand-alone principle means that only those costs, risks and benefits that arise from the provision of regulated service are borne by ratepayers. All other costs, risks and benefits incurred by the legal entity are to the account of the shareholder. The "carving out" of the stand-alone utility ensures that subsidies are neither given to nor taken from other activities or actions of the legal entity that are not required for the provision of regulated service" (Exhibit B.9, pages 7 & 8 of 31).

Ms McShane also testified that if an objective is, as stated by the government, to create a level playing field, then you would treat the electricity distributors the same way you treat the natural gas distributors (Tr. Vol. 5, pp 85). She also agreed that the stand-alone principle is applied to Ontario's natural gas utilities (Tr. Vol. 5, pp 225 – 228). Ms. McShane also agreed that the point of the stand-alone principle is to treat utility activities as if they were in a separate entity (Tr. Vol. 5, pp 211 – 212) and indicated that a stand-alone utility need not be a separate corporate structure, but for regulatory purposes, a hypothetical stand-alone entity (Tr. Vol. 5, pp. 216).

As stated in Exhibit B.9 (page 14 of 31), the OEB stated in the E.B.R.O. 496 Decision (Natural Resource Gas Limited, August 1998) that "NRG should be treated as a stand alone entity for purposes of calculating the federal capital tax to be included in NRG's cost of service" (Para 3.2.60) and the Board directed NRG "to include in its filings for future rate hearings, a detailed calculation of the income taxes included in the Company's cost of service, showing any surtaxes that the Company must pay ***<u>and any deductions to which the Company, considered on a stand alone basis, is entitled</u>***" (Para 3.2.69) (emphasis added).

Turning now to the specific wording in Section 7.1.2.4, and taking into consideration the above, it is obvious that the stand alone principle is violated and that ratepayers shoulder higher costs as a result of this section than do ratepayers of natural gas utilities in Ontario. Each of the components of this section is discussed below.

Part (i) of Section 7.1.2.4 states that all of the Large Corporations Tax exemption (currently $50 million) should go to the distributor if it is the only regulated utility in the corporate group and that none of the exemption shall be allocated to an unregulated member of the corporate group. LPMA supports this. However it is stated that if there is more than one regulated utility in the corporate group, then the LCT exemption should be allocated among these regulated utilities on a reasonable basis. LPMA strongly disagrees with this as it violates the stand alone principle. It also violates the no harm principle in that ratepayers do not get the full benefit of the reduction in the revenue requirement associated with the LCT exemption solely because there is a related regulated utility in the corporate group. Put another way, consider two utilities identical in every way except that one utility is a stand alone entity with no regulated affiliates and the other has a regulated utility as an affiliate. Ratepayers of the first utility would have lower distribution rates than those of the second utility because the second utility shares some of its LCT exemption with an affiliate. LPMA submits that it violates regulatory and ratepayer protection principles that some customers would pay higher rates simply because of corporate affiliates.

Part (ii) of Section 7.1.2.4 deals with the allocation of the provincial capital tax exemption amongst affiliates. The handbook states that "as required for tax purposes, the provincial capital tax exemption must be prorated within the corporate group based on paid up capital amounts". LPMA submits that for regulatory purposes, this irrelevant. The handbook is for regulatory purposes and in particular it deals with the calculation of the revenue requirement. Again the proposal in the handbook violates the stand alone principle of regulation for the same reasons given above. Again, it violates the no harm principle as well, for the reasons given above. The OEB cannot allow ratepayers to pay higher rates simply because a regulated utility has non-regulated (or another regulated) affiliate.

Part (iii) of Section 7.1.2.4 deals with the allocation of the LCT and provincial capital tax exemptions when distribution (regulated) and non-distribution (non-regulated) functions are undertaken in the same legal entity. Specifically, the exemptions are to be pro-rated between these functions to reflect the relative asset values in each of these functions. Again, LPMA opposes this violation of regulatory principles. Ms. McShane agreed absolutely that the point of the stand alone principle is to treat the utility activities – the regulated activities – as if they were a separate entity (Tr. Vol. 5, pp 211 – 212). As a result the same arguments apply to the allocation of the exemptions between different functions within the same legal entity as among affiliates. Ratepayers should not be required to pay higher regulated distribution rates because their utility decides they want to manufacture widgets or bake and sell cupcakes.

<u>Section 7.1.2.8 Interest deduction</u>

LPMA supports the adoption of Alternative 3 for reasons detailed above under Section 7.1.2.2.

<u>CHAPTER 9 – COST ALLOCATION</u>

<u>Section 9.2 Determination of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class, or Group</u>

The fourth paragraph in this section talks about multiplying by the 2004 class customer count (or connection count). LPMA submits that this should be clarified to read multiplying by the 2004 ***<u>year-end</u>*** class customer count (or connection count). This was what was agreed to in the working groups in which LPMA participated.

The following paragraph in this section talks about the process not producing suitable allocations because of the gain or loss of a major customer. It is LPMA's understanding that the allocation of the total distribution revenue requirement will be done on the basis of the revenue forecast (as calculated in the previous paragraph in this section) that would take into account the gain or loss of a major customer.

LPMA recommends that a material proportion of distribution revenue be defined as 2.0%.

With respect to the CDM program impacts, LPMA questions the need for such an adjustment. Such load losses are likely to be difficult to forecast, at best. In addition, if the utility has a Lost Revenue Adjustment Mechanism (LRAM), the impact of the lost load will be recorded in it. LPMA notes that if an applicant reduces its loads forecast for CDM programs, then this needs to be reflected in thr LRAM calculation. It would only be the variance (positive or negative) that would flow into the LRAM account.

<u>Schedule 9-2 Allocation Factors to Customer Classifications</u>

The columns labeled 2002 Customers, 2003 Customers and 2004 Customers should indicate Year-End Customers in all cases.

CHAPTER 10 – RATES AND CHARGES

Section 10.2 Unmetered Scattered Loads

LPMA recommends that the status quo remain in place until a complete cost allocation study is available. There is likely to a difference of opinion on how costs are to be allocated to all categories of customers in the future. In the view of LPMA, it would not make sense to change the status quo for 2006 and then potentially make another change in 2007 when the cost allocation information is available. LPMA notes that any change to the status quo will impact both unmetered scattered load and other general service customers.

Section 10.5 Update of Loss Adjustment Factor Reflecting System Losses Including Unaccounted-for Energy

LPMA does not support either of the alternatives provided. LPMA believes that the utilities should live with the forecast, as calculated, for losses. No variance accounts should be permitted for either the kWh's or the cost per kWh. Any variance from that forecast should be to the account of the shareholder. This will provide an incentive for the utility to reduce its losses and could be an effective form of CDM. Lower losses will benefit customers in the future. The use of a variance account totally removes any incentive for the utility to reduce losses.

Section 10.6 Distributed Generation

Similar to the submissions related to unmetered scattered loads above, LPMA does not see the merit in changing the status quo for 2006 only to have it changed again for 2007 as part of a complete cost allocation and rate design process.

CHAPTER 13 – MITIGATION

Section 13.2 Mitigation Methodologies

LPMA does not support any mitigation measures that are related to the fixed/variable split for 2006. Any such changes should be driven by cost allocations, which will be available for setting 2007 rates. Changes in the fixed/variable split for mitigation purposes may, in fact, be in the wrong direction once the cost allocation process is incomplete. Reversing the change in 2007 would only confuse customers.

LPMA also does not support any rate mitigation measures that fail to recover the Board approved revenue requirement. Any shortfall in revenues due to rate mitigation would either affect the financial viability of the utility, or place a burden on future distribution customers.

If the financial health of a utility is affected, LPMA is concerned that safety and/or service quality would be negatively affected. If the revenue shortfall were to be recorded in a deferral account (with or without interest) to be recovered in a future period from customers, LPMA is concerned with the inter-generational cost shift this would create. It would only be making a bad situation now into a grave situation in the future.

LPMA notes that the provincial government has indicated that customers need to pay the real cost of power. LPMA submits that the Board should make sure customers also pay the real cost of the distribution of that power. Through this process the Board must ensure that every component of the overall revenue requirement for a utility is just and reasonable. This will ensure that customers pay no more than required. At the same time the Board must ensure that customers do not pay something less than the real cost of the distribution of the power. If this were to be the case, it would undermine the entire concept of CDM. Price is one of the most effective methods of getting consumers to reduce their consumption. The government initiatives related to smart meters and time-of-use rates reflect this. It would not be reasonable, then from a policy perspective to have customers pay less than the true cost of distribution. On one hand utilities, the OPA, the Board and the government are trying to instill a culture of conservation while on the other hand, lower than required distribution rates would be encouraging higher consumption.

With respect to rate harmonization, LPMA submits that it would be more efficient and sensible to delay rate harmonization until the cost allocation study is completed for the 2007 rate year. Thus LPMA supports Alternative 2.

<u>CHAPTER 14 – COMPARATORS AND COHORTS</u>

<u>Section 14.2 Filing Requirements</u>

If the Board determines that data is to be filed by the distributors, then LPMA submits that this data should be available to all interested parties. LPMA supports Alternative 3 and recommends that Board Staff prepare an electronic copy (Excel) for all the distributors and make this information available to the public on their website.

Providing the data to only some parties and not to others is unfair in what is supposed to be an open and public process.

<u>APPENDIX B – RATE BASE ACCOUNTS</u>

Previous comments related to the definition of rate base and the level of detail available applies equally to Appendix B. LPMA is also concerned with the apparent lack of detail for accumulated depreciation expense in Table B.1. Table B.1 contemplates accumulated depreciation being available in two large groups. Again, more detailed information, which the utilities should possess may be required in 2007 for the cost allocation process in order to fairly and accurately functionalize, classify and allocate the components of rate base to the various customer groups and sub-groups.

All of which is respectfully submitted this 10th day of February, 2005 on behalf of the London Property Management Association by their Consultant.

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Randall E. Aiken
Aiken & Associates