COST OF CAPITAL (EB-2006-0088) AND 2ND GENERATION INCENTIVE REGULATION MECHANISM (EB-2006-0089)

FINAL WRITTEN COMMENTS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

I. INTRODUCTION

By letter dated October 11, 2006, the Ontario Energy Board invited participants in EB-2006-0088 and EB-2006-0089 to make final written comments following the technical conference. These comments are on behalf of the London Property Management Association ("LPMA") and have been divided into three main sections dealing with the Cost of Capital, the 2nd Generation Incentive Regulation Mechanism and Implementation Issues.

LPMA is looking for an outcome that is balanced in terms of the interests of ratepayers and shareholders, results in distribution rates that are just and reasonable and is based on a solid and tested evidentiary basis.

II. COST OF CAPITAL

The cost of capital review uses the benchmark December, 1998 paper by Dr. Cannon entitled "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario". This has become known as the Cannon Methodology.

The comments on the cost of capital issues have been divided into a number of topics, as listed below.

a) Return on Equity and Adjustment Mechanism

At page 4 of the July 25, 2006 Staff Discussion Paper, it is stated that the approved Codes will set out the methods and techniques to be applied by the Board in adjusting rates for distributors for a transitional period of up to three years (depending on the distributor as explained Section 4). It is assumed that this applies to the Cost of Capital Code as well as the 2nd Generation Incentive Regulation Mechanism Code. As such, any changes to the cost of capital and/or capital structure that may emerge from this process are likely only to be transitional in nature and subject to change in a relatively short period, especially considering that the transition period has been identified as period of UP TO THREE YEARS. For many distributors, the transition period will only be one or two years in length.

LPMA submits that due to the transitional nature of any such Cost of Capital Code and the short duration of any such transitional period, there is no basis to depart from the Cannon Methodology. Indeed, there are several compelling reasons to maintain the existing approach. The advantages associated with the retention of the Cannon methodology are explained in more detail below.

LPMA submits that the process that has been followed in this discussion on the appropriate methodology to determine a proper return on equity has been flawed and is not an appropriate way to deal with an issue as complex and as significant to both ratepayers and shareholders as this issue is.

In support of this, LPMA notes that there is no evidence as a result of this process. As Mr. Fogwill stated at the October 17, 2006 Technical Conference: *"This is not evidence. It's a consultative process that involves the conversation amongst a number of stakeholders."* Mr. Fogwill went on to state that *"We don't test evidence through this process."*

As a result, the conversation that took place through this process was wide ranging in terms of both the ultimate ROE that was put forward by various parties, to the appropriate methodology that should be employed in coming up with those suggested rates, to the more mundane issue of whose mathematics were correct.

Based on current interest rates, the range of appropriate ROEs is significant. Suggestions vary from a range suggested by Drs. Lazar & Prisman of 6.61% to 8.37% (with Board

Staff recommending the 8.37%), to a range of 9.8% to 12.2% provided by Christensen Associates. Ms. McShane suggests a return of 10.5% is appropriate while Dr. Booth has stated that if asked to submit formal cost of capital evidence, he would have recommended both a lower ROE and less common equity than that proposed by Board Staff. Thus, it is apparent that there is a wide range of views on the appropriate level for the ROE ranging from a low of 6.61% to a high of 12.2%, or almost double. The impact on Ontario ratepayers and utility shareholders of this range of returns is huge, ranging from tens of millions of dollars to hundreds of millions of dollars. Again, because of the lack of any tested evidence, the dollar value is not known with certainty.

It has also been suggested by a number of parties that the financial markets are following this process very closely and that the outcome may have a significant negative impact on the ratings of utilities. Of course this is only conjecture at this point, but LPMA believes that the Board should be aware of the potential fallout that may result from this process.

LPMA believes that the best direction for the Board to take at this point, in the absence of full evidence and its testing in a full rates or generic proceeding, is to continue with the status quo. That is, the Cannon Methodology should be applied properly, in the same manner as the Board does for the natural gas industry.

LPMA strongly believes that if the Board were to change the level and/or methodology used to determine the allowed ROE for electric utilities in the absence of a full rates/generic proceeding with evidence provided by parties that is subject to a rigorous review and testing by all parties, the Board would be making a serious mistake. The credibility of the Board would be seriously impacted. The perception of regulatory risk would increase substantially for all parties involved. The financial community would most likely react negatively to such a significant departure from previous Board processes on such a significant issue. The result could very well be higher equity and debt costs for utilities in both the short and long term. This would negatively impact the industry and ratepayers in particular. Higher rates would not only have a negative impact on residential customers, but would result in serious consequences to the competitiveness of commercial and industrial businesses, slowing the provincial economy. Institutional customers would also be adversely impacted, resulting in even more hardship and difficulty for schools and hospitals, among others, to balance their budgets.

Retention of the Cannon Methodology provides a number of benefits. First, it is simple and easy to apply to all utilities. Second, it provides a ROE that is in line with what is being allowed elsewhere in Canada. Third, it is similar, if not identical, to the methodologies currently being used in several other regulatory jurisdictions in Canada. Fourth, it provides stable and predictable outcomes for all parties involved. Finally, it is understood and accepted by the financial markets in this country.

The Cannon Methodology provides a number of other benefits as well. It provides symmetry and equity between the natural gas and electricity industries in Ontario. LPMA notes that Board Staff have indicated that they have assumed that all rate-regulated companies have similar risk profiles and compete for the same capital. Applying the same methodology to both industries to determine the appropriate ROE is, therefore, logical.

Moreover, the Board has relatively recent experience in reviewing the existing methodology on the natural gas side. The RP-2002-0158 proceeding dealt with a review of the Board's Guidelines for establishing the return on equity for both Union Gas and Enbridge Gas Distribution. In that proceeding, the Board heard detailed evidence from Ms. McShane on behalf of both Union and Enbridge, Drs. Booth and Berkowitz on behalf of the CAC, IGUA and VECC and from Dr. Booth on behalf of Board Staff.

At a long-term Government of Canada bond yield of 6.00%, the Guidelines produced an ROE of 9.71% for Enbridge and 9.86% for Union, reflecting risk premiums of 371 basis points for Enbridge and 386 basis points for Union. The risk premiums recommended by Ms. McShane was 450 basis points, by Dr. Booth was 250 basis points and by Dr. Cannon was 210 basis points. The Board found that on the basis of the record in that proceeding that Dr. Cannon's result was too low and that Ms. McShane was too high.

The Board concluded that the results provided by the Guidelines continued to provide fair and reasonable returns. In particular, the January 16, 2004 Decision and Order in the RP-2002-0158 proceeding concluded:

> "*with respect to the first and primary issue of whether a new benchmark ROE should be established for EGDI and Union, we find that the current ROE Guidelines methodology continues to produce appropriate prospective results. We have not found any demonstrated need to set a new benchmark ROE*" (para. 142).

The Board then went on to conclude that no change to the adjustment factor of 0.75 was needed.

The Board set the ROE at 9.00% in the 2006 Rate Handbook (RP-2004-0188 Report of the Board dated May 11, 2006). As shown in Section 5.1 of the Handbook, the ROE of 9.00% included an equity risk premium of 3.80% and a long-term Canada bond rate of 5.20%. Adjusting this ROE to reflect a 6.00% long Canada bond rate to make the ROE comparable to the ROE's for Enbridge and Union noted above, would result in an ROE of 9.60% (0.75 x (6.00 – 5.20) + 9.00) and an equity risk premium of 360 basis points. This is comparable to that of Enbridge and Union at the same long-term Canada rate.

Based on the above, LPMA believes that using the existing methodology provides a reasonable equity risk premium and is based on a recent Board review of detailed evidence.

Board Staff has asked for an opinion on the appropriate application of the Cannon Methodology in calculating the ROE. In the response to Question 15 from the Coalition of Large Distributors dated October 11, 2006, Board Staff have presented three options, or interpretations of the Cannon Methodology. These options are based on the August 14, 2006 Consensus Forecasts and actual August difference between 10-year and 30-year Government of Canada Bond yields resulting in Long Canada Bond yield of 4.56%.

Table 1 of the Board Staff response assumes a fixed equity risk premium and only adjusts for the long Canada yield, resulting in an ROE of 8.36%. Table 2 starts with the 9.00%

ROE from the 2006 Handbook and adjusts the ROE using the 0.75 adjustment factor from the Cannon Methodology, resulting in an ROE of 8.52%. The third table uses the same adjustment factor, but starts with the ROE and Long Canada Bond yield from The RP-1998-0001 Decision and results in an ROE of 8.65%.

There appeared to be some confusion at the Technical Conference of why Board Staff used this third approach in place of starting with the original 9.88% ROE from the first Rate Handbook. The reality is that the result is the same regardless of the starting point. The 9.88% ROE was based on a Long Canada Bond yield of 6.20%. Reflecting the proper adjustment for the decline in the Long Canada Bond yield to 4.56% would result in an ROE of 8.65%% (0.75 x (4.56% - 6.20%) + 9.88%), the same ROE as calculated by Board Staff in Table 3.

The issue of how to calculate the ROE using the existing methodology is really two-fold. First, should an adjustment factor of 0.75 be used and second, what is the proper starting point for the calculation.

On the first issue, the Cannon Methodology clearly supports the use of the 0.75 adjustment factor. This has been the practice in the natural gas determination of the ROE. This adjustment factor was utilized in the RP-1998-0001 Decision, but was not used in setting the ROE of 9.00% used in the 2006 Distribution Rate Handbook. LPMA believes that the adjustment factor of 0.75 should be used to adjust the ROE for changes in the Long Canada Bond yield. This is consistent with the Cannon Methodology and the Guidelines used by the Board for the natural gas utilities.

On the second issue, LPMA believes that the proper starting point for calculating the adjustment to the ROE is the most recent Board Approved ROE, or 9.00% as calculated in the 2006 Distribution Rate Handbook. As noted in the Handbook, this ROE was based on a Long Canada Bond yield forecast of 5.20%. This corresponds to an ROE of 8.52% at the Long Canada Bond yield of 4.56% using the August Consensus Forecast and is shown in Table 2 of the Board Staff answer to Question 15 from the Coalition of Large Distributors referenced above.

A related issue is what Consensus Forecast should be used to determine the Long Canada Bond yield needed to calculate the ROE. The Board's Guidelines on the natural gas side specify that the October Consensus Forecast is to be used for Union and Enbridge, both of which have fiscal years that correspond with the calendar year. Since rates are set for the electric utilities on a calendar year basis, even though rates are not implemented until May, LPMA suggests that it would be logical for the October consensus forecast to be used for the electric utilities as well. This would result in simplicity to administer and consistency between gas and electric utilities. More importantly, it would provide the financial community with certainty regarding the allowed ROE for the electric distributors on an equally timely basis as the current process for the gas distributors.

b) Incentive for Investment

Board Staff have raised the issue of the necessity to raise significantly higher levels of capital for infrastructure upgrading and expansion and whether this need may justify an additional premium to the ROE, possibly in the range of 50 to 150 basis points.

LPMA submits that if the ROE is set properly, there is no need to provide an additional premium for incremental capital expenditures. There is a total lack of evidence to suggest that utilities have any market access problems at the current ROE. There is also a lack of evidence to support widespread need for significantly higher level of capital expenditures across the province.

In addition to the lack of evidence noted above, LPMA submits that allowing a two tier rate base would appear to be unnecessarily complicated and would add to the regulatory burden of not only the utilities but also to the Board. Such a system would be administratively difficult to process. Evidence would be needed to provide justification for the need and timing of the capital expenditure, along with the quantification of the increase in rate base over the Board Approved 2006 levels. This would require adjusting the 2006 rate base figure for future increases in accumulated depreciation and retirements from plant, in addition to the capital additions.

Allowing a higher return on equity for the component of rate base in excess of the 2006 rate base without reviewing the other cost impacts on a revenue requirement would not result in just and reasonable rates. Additional capital expenditures related to system expansion ultimately end up producing additional revenues from new customers and sales. New capital expenditures result in lower payments in lieu of taxes through the increase in the capital cost allowance deduction. These benefits may more than offset the increase in the cost of capital, depreciation and other incremental costs. Similarly, additional capital expenditures that are completely related to upgrading the existing system, while not producing additional revenues, may result in lower overall costs. Again, the capital expenditures would generate additional capital cost allowance deductions and the upgrading of old equipment would most likely result in lower operating and maintenance costs. Another significant positive impact could be a reduction in line losses.

It should also be understood that the impact on the return to the utility would be relatively small. For most utilities, significant capital expenditures are needed to keep rate base from declining, through the normal increase in accumulated depreciation. As well, since rate base is essentially the average of the opening and closing account balances, capital expenditures in excess of that required to simply keep rate base from declining would only result in an increase in rate base of 50% of this additional capital spending. On top of that, only the deemed equity portion of the incremental rate base (i.e. 35% to 50%) would attract the higher ROE. If a utility needs to spend more than that needed to keep rate base at its 2006 level, the impact on the revenue requirement would be relatively small, as shown in the following example:

Incremental capital expenditures that increases rate base:		$1,000,000
Impact on Rate Base	x 50%	$ 500,000
Impact on Equity	x 35% to 50%	$175,000 to $250,000
Incremental Return on Incremental Equity	x 50 to 150 bps	$875 to $3,750.

Thus, for every $1 million in capital expenditures over and above that needed to maintain rate base at the 2006 level would result in additional revenue of $875 to $3,750 per year.

In additional to the relatively small impact on revenues of such a scheme, allowing a two tiered ROE raises some serious concerns about how those costs should be allocated. If incremental expenditures are required for specific groups of customers, should the higher cost of equity be allocated only to those customers or that class of customers?

In summary, LPMA does not believe it is either necessary or desirable to provide an additional premium for capital expenditures that increase rate base. As an alternative, LPMA suggests that utilities that believe they will be faced with such a situation where they require significantly higher levels of capital for infrastructure upgrading or expansion should be the first in the queue to bring forward their future test year rebasing applications to the Board.

c) Capital Structure

Board Staff recommends adjusting capital structures so that one size fits all, a significant change from that in the first two generation handbooks. LPMA recommends that the Board stay with the current differentiation as found in the 2006 Rates Handbook.

The current differentiation is based on the premise that the risk is related to the size of a distributor. Rate base is used as a proxy for size. LPMA generally agrees with parties who have indicated that this may not be the best measure of risk. For example, a small utility that serves nothing but residential customers would likely be less risky than a utility with a larger rate base, but has a concentration of industrial loads in declining industries. Similarly two utilities of equal size rate base wise but where one is predominantly rural and geographically diverse and the other predominately urban and small geographically, may well not be equal in risk.

The problem with changing the status quo as part of this process is that there is no evidence before the Board that can be used to disprove the premise that risk is related to size. Even more significantly, there is also no evidence before the Board to suggest, as Board Staff assumes, that all utilities have the same level of risk. By proposing the same ROE and same deemed capital structure for all utilities, this is what Board Staff is assuming. While LPMA believes there may be something other than rate base that should or could be utilized to differentiate risk among utilities, LPMA does believe that there are differing levels of risk.

d) The Next Step

LPMA submits that the Board should maintain the status quo on the ROE and capital structure until it investigates this issue in a generic proceeding. A full review, similar to what the Board did in RP-2002-0158 on the natural gas side, is what is needed to determine if changes are needed, and if so, what those changes should be.

During the Issues Day of the RP-2004-0188 process (November 1, 2004, Vol. 1, para. 581), the Board indicated that it would "initiate an industry-wide process to study return on equity and associated issues". LPMA submits that the current process cannot be construed as a study. A study requires close examination and review of evidence. A generic hearing into this issue is required to properly study the issues. LPMA believes such a generic hearing is needed if the Board determines that a change from the current Cannon Methodology is or may be in the public interest.

e) Debt Rate

It is not clear to LPMA why a formula for determining a deemed cost of new affiliated debt is required, as proposed by Board Staff. During the transition period of 2007 through 2009, no adjustments are proposed to be made that would reflect changes in the cost of debt. The K factors proposed by Board Staff would reflect changes in the ROE and the capital structure but not in the cost of debt (Staff Discussion Papers, pages 20 and 21).

If a formula is wanted for new affiliated debt that is brought forward at the time of rebasing, then LPMA believes a formula approach will not work. Not all utilities are able to borrow at the same premium over a riskless rate. Any utility that brings forward new affiliated debt at the time of its rebasing should be expected to provide specific evidence to support the rate they are paying.

LPMA is also concerned that by approving a formula, affiliated debt will have a minimum rate that would be charged that may, in fact, be higher than that required by the affiliate. This only results in higher costs to be paid by ratepayers.

f) Level of Short Term Debt

As a general principle, LPMA believes that the term of debt should match the life of the assets that are to funded with that debt. Board Staff's proposal to set the level of short term debt equal to the level of the working capital allowance component of rate base is justified in theory. However, there are practical considerations that should be taken into account.

If a utility has a stable level of capital expenditures and its rate base remains relatively stable, then it would be logical that the working capital allowance component of rate base should be funded through short term debt. This is because the working capital allowance reflects short term capital needs.

Practical considerations, however, may make this approach impractical. The Board has heard submissions in this process and in the numerous rate cases for the natural gas utilities that capital is lumpy. This means that utilities may acquire more long term debt than is required over the short term, or they may have more short term debt than short term assets until they reach a point where it is practical to obtain long term debt.

The Board has extensive experience on the natural gas side of utilities actually having a deemed negative short term debt component of their rate base. For example, the RP-2005-0544 Decision for Natural Resource Gas Limited, dated Sept. 20, 2006, resulted in short term debt component of rate base of -8.21%. This outcome is not unique to small utilities. In the RP-2005-0520 Decision for Union Gas Limited, the short term debt component of rate base was -0.9%, or more than $30 million.

Board Staff have suggested setting the short term debt component at 8% of total rate base, based on Hydro One's lead lag study filed in its 2006 EDR case. LPMA does not support this approach.

Given the range of utilities in Ontario, there is significant doubt that 8% is a correct figure for all the distributors. LPMA notes, for example, that in the London Hydro 2006 EDR filing the working capital allowance was closer to 20% of the total rate base.

Further, given the comments above about the lumpiness of capital, it may not be appropriate to set the short term debt component at a pre-determined level.

LPMA suggests the following approach, which is followed by the gas utilities. The short term debt component of rate base is generally a plug figure. That is, it is the amount or share of rate base that is required to balance total rate base with the deemed equity amount and the actual long term debt held by the utility. In particular:

Short Term Debt = Rate Base – Deemed Equity – Actual Long Term Debt.

This allows short term debt to be positive or negative, reflecting the lumpiness of actual long term debt. This approach allows the utility to recover the actual costs associated with long term debt. The Board Staff approach may not. For example, if the actual long term debt was 65% of rate base, the utility would not be able to recover the full cost, since they would be limited to 57% (65% less deemed 8% for short term debt) of rate base at the long term debt rate.

The approach recommended allows utilities to recover all their long term debt costs (subject, of course, to appropriate rates for affiliated debt). If the actual long term debt plus deemed equity is in excess of the total rate base, then the short term debt is negative and at the short term debt rate, this results in a reduction to the total cost of capital. This is the standard approach and outcome in the gas industry and should be applied to the electric industry as well.

Administratively, this is simple to do. Each utility has filed the amount of long term debt it has in its 2006 EDR filings. Combining that information with the deemed equity component and the total rate base - both of which are also found in the 2006 EDR filings - the short term debt component for each individual utility can be easily and readily calculated.

It is also unclear to LPMA how the Board Staff proposal would work. Assuming a deemed 8% of rate base was determined to be short term debt at some prescribed rate, it is assumed that Staff would have to go back remove the 8% of rate base from the long term debt component that would now be considered short term debt. Given that the long term debt rates are unique to each utility and that each utility has a unique level of rate base, the amount of the reduction in the cost of long term debt would have to be calculated on a utility by utility basis. Therefore, there is no difference from an administrative point of view of the Board Staff proposal and that of LPMA.

If Board Staff had envisioned a generic one size fits all adjustment related to a deemed level of short term debt, LPMA does not believe that would be appropriate. Such an approach could not result in just and reasonable rates for all utilities and their ratepayers. This is discussed in more detail below in relation to the K factor adjustments.

g) K Factors

Board Staff have proposed calculating the “K” factors used to adjust rates for changes in the ROE in 2007 and to reflect changes in the capital structure in 2008 based on a large sample of distributors, but then ultimately determining size-group K factors and then applying this average to each distributor in that size category. Board Staff state that a K factor cannot be calculated for all distributors in the province.

In both cases (i.e. 2007 and 2008) LPMA does not believe it is appropriate to use an average of adjustment factors and apply this average to all utilities within a size grouping. In its' August 14, 2006 letter to the Board, VECC did an analysis (page 13) of the 2006 rate application data posted on the Board's web-site. This analysis indicated that the return on equity component of the base revenue requirement ranges from less than 7% to more than 20% of total distribution expenses for distributors that fall within the same capital structure (size) category. Given this large variation, it is likely that utility specific K factors will also vary widely from one another.

Applying an average K factor will not result in just and reasonable rates. This is because the application of an average K factor will either result in a higher or lower adjustment to rates than if the utility specific K factor is used. The result is that in one case the price cap will be higher than it should be for the specific utility, resulting in ratepayers paying more simply because of the K factors for other utilities that do not serve them. On the other side of the equation, the price cap will be lower than it should be for the specific utility, resulting in the utility being unable to earn the allowed return, again simply because of different K factors from other utilities. In summary, the process proposed by Board Staff builds in an automatic bias that affects both ratepayers and shareholders. As such, rates will not be just and reasonable.

LPMA believes that utility specific K factors should be calculated and used for each distributor. This can easily be accomplished, given the information available to Board Staff in the 2006 EDR filings that reflect Board approvals.

With respect to the K factor proposed for 2008 related to changes in capital structure, LPMA notes that it has submitted that it does not believe an adjustment to the deemed equity component is justified as part of this process. However, even if the Board agrees with this, there would still need to be an adjustment to reflect the change in the capital structure related to the proposed inclusion of short term debt. The Board Staff proposal is silent on how the short term debt component of capital structure would be implemented in the price cap formula, but since it is a change in capital structure, it is assumed that it is part of the 2008 adjustment.

The K factor adjustment for a change in the ROE for 2007 is based on the premise that such an adjustment should be done. Board Staff asked parties to comment on whether or not the ROE should be updated for May 1, 2007 distribution rate adjustments. Based on the written responses received from both utilities and ratepayer groups, there appears to be near unanimous agreement that the ROE should be updated. LPMA agrees with this assessment. As noted earlier in this submission LPMA further believes that the ROE for 2007 should be updated based on the October, 2006 Consensus Forecast, consistent with the data used to set the ROE for Union and Enbridge for 2007.

III. 2ND GENERATION INCENTIVE REGULATION MECHANISM

Comments on the various components of the 2nd generation incentive regulation mechanism (IRM) are provided below. Comments have been limited to the specific details of the proposed price cap. LPMA believes that the 2nd generation IRM should not unduly influence the design of a 3rd generation IRM.

a) K factor

Board Staff have proposed that the K factor adjustment for ROE would be one-time adjustment in 2007 and that there would be no additional adjustments throughout the 2nd generation IRM term for changes to ROE. LPMA agrees with this proposal.

The proposed inflation factor, Canadian GDPPI – Final Domestic Demand, tracks some changes in market returns and the cost of capital. The Board has experience with this issue based on the Union Gas RP-1999-0017 Decision (July 21, 2001) that implemented a comprehensive performance based regulation (PBR) mechanism for Union for 2001 through 2003 that also used GDPPI as the inflation factor. In that Decision the Board determined that there would be no ROE adjustment for the years under the PBR plan. In particular, the Board stated at paragraphs 2.367 through 2.369 of the RP-1999-0017 Decision With Reasons:

> *The Board is of the view that an ROE or debt rate pass-through mechanism is not consistent with a comprehensive price cap PBR plan for a number of reasons. The Board notes that an ROE pass-through is not a typical feature of a comprehensive PBR plan.*
>
> *The Board notes that the effect which inflation might have on the determination of a fair allowance for ROE is, to a significant extent, captured by annual changes in the GDPPI component of the PCI* (price cap index). *The impact of the differences in capital intensity between Union and industrial companies in general is captured in part through the appropriate determination of the input price differential. In the Board's judgement, the components of a fair ROE, which reflect the risks to which the utility is exposed, are captured under a PBR approach, to a large extent, through the application of an appropriate price cap escalator that includes the I-factor and the X-factor.*
>
> *The Board is of the view that in a comprehensive PBR plan, the escalation of the factor inputs (such as materials, labour and capital) should be captured by the price cap escalator. The Board notes that there is no mid-term adjustment or pass-through proposed for inputs such as labour and materials, nor for the debt component of the cost of capital. A PBR plan is intended to provide incentives for the Company, over the term of the plan, and subject to constraints on quality of service, to maximize profits by minimizing costs, profits here being the difference between revenues and non-equity costs.*

LPMA suggests that there is no reason to deviate from the above Board Decision with respect to this issue. The Board dealt with a possible adjustment for the ROE on annual basis in the same context with Union Gas as is now before the Board for the electric utilities and found it was not warranted. Nothing has changed since that Decision.

<u>b) Term and Starting Base</u>

LPMA accepts the proposed term of the plan of up to 3 years. This will allow the Board to rebase the 90 or so utilities over three years. This would appear to be a manageable work load for the Board, utilities and intervenors.

LPMA also agrees that base rates should be the 2006 rates, which by definition, have been determined by the Board through the 2006 EDR process to be just and reasonable. However, LPMA does believe one adjustment to the 2006 rates is required. This change is related to the elimination of the federal capital tax (large corporation tax) effective January 1, 2006. As per the EDR Handbook, this tax saving in 2006 will be booked into a deferral account. Given that this tax has been eliminated, the price cap index should be adjusted by a factor to reflect this. Without adjusting for this reduction, the price cap would in fact be indexing an amount that is no longer part of the revenue requirement. LPMA suggest this would be simpler to administer than to continue the deferral accounts and record the amount included in the 2006 revenue requirement grossed up each year for the price cap index. LPMA also notes that this adjustment would only need to be calculated for the larger utilities as small utilities with a rate base of less than $50 million would not have had any of this capital tax included in their revenue requirement. LPMA suggests the adjustment factor could be calculated in the same manner as the K factor proposed for the change in ROE for 2007. Similarly, the adjustment would only be included in the 2007 price cap calculation.

c) Price Escalator

LPMA supports the use of the GDPPI – Final Domestic Demand as the proxy for inflation. This measure is preferable to the Consumer Price Index (CPI) because it tracks a more relevant set of goods and services used as production inputs by businesses, including such items as capital equipment. The CPI, on the other hand, tracks the prices of consumers good and services. The Board accepted the use of GDPPI as the appropriate measure of overall price inflation in Union's PBR plan.

Due to timing issues, LPMA supports the use of the Canadian GDPPI instead of the Ontario figure. The Ontario GDPPI data is not available in time to implement rate changes for May 1 of each year, whereas the Canadian data is.

LPMA also believes that the final domestic demand version of the GDPPI is preferable to the overall economy GDPPI as it more accurately reflects the inputs to electricity distributors.

Board Staff proposes that the calculation be based on the latest historical data available as a proxy for the following year. LPMA agrees with this. However, LPMA does not agree with the use of the fourth quarter over fourth quarter calculation proposed by Board Staff.

In its August 11, 2006 comments to the Board, LPMA proposed that the calculation be done on the annual figures. For ease, this analysis has been replicated here. The table below shows the impact of using the 4th quarter over 4th quarter calculation as compared to the annual index levels in calculating the percentage change over the 2001 through 2005 period.

	Final Domestic Demand (Quarterly) V1997757			Final Domestic Demand (Annual) V3860249	
2000 IV	105.9		2000	105.0	
2001 I	106.0				
2001 II	106.9				
2001 III	107.1				
2001 IV	107.3	1.3%	2001	106.8	1.7%
2002 I	108.1				
2002 II	108.8				
2002 III	109.7				
2002 IV	110.4	2.9%	2002	109.3	2.3%
2003 I	110.8				
2003 II	110.3				
2003 III	111.3				
2003 IV	110.9	0.5%	2003	110.8	1.4%
2004 I	111.6				
2004 II	112.7				
2004 III	112.8				
2004 IV	113.0	1.9%	2004	112.5	1.5%
2005 I	113.7				
2005 II	114.6				
2005 III	115.1				
2005 IV	115.3	2.0%	2005	114.7	2.0%
Average (5 years)		1.7%			1.8%

As the above table shows, the fourth quarter over fourth quarterly inflation figures range from 0.5% to 2.9%, while the increase in the annual figures range from 1.4% to 2.0%. Over this five year period, the average increases are virtually the same at 1.7% and 1.8%, respectively. What this illustrates is the volatility that is inherent in using the fourth quarter over fourth quarter approach. Given the desire for a stable environment, the use of the annual figures (which are available from Statistics Canada at the same time as the release of the 4th quarter data) is more reasonable.

It should also be noted that that the impact of revised data is greater when using the fourth quarter data as compared to using annual data. The annual figure is the average of the four quarterly figures for the year, so any revision in the fourth quarter figure is moderated in the annual figure.

For the Board's information, at the time of the August 11, 2006 submission from LPMA, the latest GDPPI figure available was for the first quarter of 2006. The first quarter over first quarter growth rate was 1.8%. Using the annual approach, the increase was 1.9%. The second quarter 2006 information was released at the end of September. As part of that release, the first quarter 2006 figure was revised. The first quarter over first quarter growth rate was revised to 2.4%, while the revision changed the annual approach to 2.0%. This real world example shows the advantage of using the annual approach over the quarterly approach.

d) X-factor

LPMA believes that the Board Staff proposal for selecting an X-factor is appropriate for the transitional 2nd generation IRM. Research on input price differentials, productivity differentials and stretch factors should be utilized as the basis for a 3rd generation IRM, but cannot be done in time for the current process.

The information provided in Table 1 on page 55 of the Pacific Economics Group report should be used to set the X-factor over this transitional period, as proposed by Board Staff. However, LPMA does not agree with the proposed 1.0%. A review of Table 1 reveals an error in the calculation of the sample average for plans that use a macroeconomic inflation measure (i.e. GDPPI or CPI). The actual average for the 10 such companies where a macroeconomic inflation figure is 1.16%, not the 1.01% shown in the table. As a result, LPMA submits that proper X-factor based on the PEG report should be 1.2% LPMA notes that this X-factor is relatively modest in comparison to the 2.5% the Board set for Union Gas.

e) Z-factors

LPMA is generally in favour of the limited and specific Z-factors as proposed by Board Staff. That is, Z-factors should be limited to changes in regulation, changes in accounting or tax rules and rates, and natural disasters. LPMA does not believe that other items such as regulatory assets, rate adders or CDM costs are true Z-factors. This is because the related costs for these items are outside of the rate adjustment mechanism framework. These items are more properly classified as pass-through items.

The price cap adjustment should be applied to base rates which exclude the pass-through items. This is the methodology approved by the Board for Union Gas in RP-1999-0017. In other words, rate adders, rates associated with the recovery of regulatory assets, and rates associated with CDM costs should be removed from the total distribution rate, the price cap applied and these rate adders and rates associated with pass-through items added to determine the new distribution rate. This is because pass-through costs, such as the recovery of regulatory assets, do not need to be grossed up. It would also provide for inequitable treatment of such costs between those utilities that rebase in the first year as compared to those that do not. If the price cap was applied to the pass-through costs, those utilities that do not rebase in the first year would end up recovering more than a utility that did rebase. This is clearly not a desirable outcome.

Further, LPMA suggests that pass-through costs should be that, a pass-through of the actual costs incurred. As such there should be variance accounts associated with each pass-through item. This ensures that utilities will be able to recover all such costs and at the same time ensures that ratepayers do not pay anything in excess of the actual cost.

LPMA made extensive submissions regarding the need to adjust rates for tax changes that been announced since the development of the 2006 EDR Handbook in its August 11, 2006 letter to the Board, beginning at page 5 of 8, and are not repeated here. LPMA supports the Board Staff proposal that unanticipated and material changes in tax rules during the 2nd generation IRN be treated as a Z-factor.

f) Earnings Sharing

LPMA views the use of an earnings sharing mechanism as a counterbalance to Z-factors. Utilities may be able to bring forward additional costs or apply for an exemption to the code in order to bring forward additional costs to be recovered from ratepayers.

Ratepayers require a balance to Z-factors. A deadband of 100 basis points over the ROE (as determined annually through the Cannon methodology) would provide utilities with an incentive to become more efficient. Any earnings over above that level should shared with ratepayers on 50/50 basis. In our view, this allows utilities to seek efficiency improvements, while ensuring that excessive gains are shared with ratepayers. This is particularly important in light of the conservative X-factor that is likely to be part of the price cap. An earnings sharing mechanism protects ratepayers from misspecification of the other price cap parameters. Given that these parameters are being set in the absence of tested evidence, an earnings sharing mechanism will protect consumers.

g) Capital Investment Factor

Hydro One and other utilities have proposed the addition of a capital investment (CI) factor to the price cap formula. The rational for this is that some utilities may have a need for significant capital investment for which a price cap may not offer sufficient incentive to undertake at this time.

LPMA does not believe that a CI factor is required for the 2nd generation IRM, due to its short time frame and the plan to rebase utilities on a staggered basis. LPMA does believe, however, that the calculation of the CI factor could be used by Board Staff to determine which utilities should be allowed/required to rebase as part of the first tranche for 2008 rates.

The calculation of the CI factor assumes that the growth in rate base is offset by the GDPPI and X factors, and an adjustment for load growth. However, there could well be other offsetting factors. For example, replacement of aging facilities would most likely result in reduced operating and maintenance costs, especially early on the lives of assets with long lives. One would also expect a reduction in distribution losses associated with new equipment compared to old. Neither of these factors is taken into account in the CI factor formula that has been proposed.

The proposal also assumes that the replacement of an existing asset with a new facility will increase rate base by the cost of the new asset, I. However, the removal from service of the existing asset may well reduce rate base. If the asset that is being retired/replaced is not fully depreciated, then its net asset value is removed from rate base. No provision has been made for this in the current Hydro One proposal.

LPMA is also concerned with the load growth estimate used in the calculation. It is unclear to LPMA how this growth would be calculated based on 2006 rate filing information for all the utilities that used the historical year approach.

If a CI factor I is included in the price cap calculation, LPMA offers the following amendments to that proposed by Hydro One.

First, if a CI factor is to be applied, it should be mandatory for all utilities to include it in the price cap. Only requiring utilities with a significant increase in capital expenditures to increase the price cap is not just and reasonable. The use of the CI factor must be symmetric. The CI factor calculation may be negative. A utility with no growth in rate base and no growth in load, would have a CI factor of -0.5%, assuming GDPPI – X of 1% and a capital cost ratio of 50%. Indeed, if load growth were 2% with no rate base growth, the CI factor would be -1.5%. LPMA notes that this approach may assist utilities that have negative load growth deal with the productivity factor. As an example, a utility with no rate base growth and a reduction in load of 2% would have a CI factor of 0.5%.

Second, if the Board were to determine that only utilities with a CI factor above a certain threshold, for example 0.5%, should include them in the price cap, then only that portion of the CI factor above the threshold level should be added into the price cap. In a simple example, a utility with a CI factor of 0.5% would not get any price cap relief, but a utility with a CI factor of 0.6% would get the full increment of 0.6%. LPMA suggests in this scenario, the increase in the price cap should be 0.1%. This would effectively treat all utilities equally up to the threshold and only allow an incremental increase for those utilities above the threshold.

Third, the investment amount used in the calculation of the CI factor should exclude any investments related to smart meters and CDM investments since these investments are not included in the portion of distribution rates that is to be adjusted by the price cap, as shown in Figure 4 of the Board Staff Discussion Paper.

Finally, only the actual net costs associated with capital expenditures should be recovered from ratepayers. This would be accomplished through the use of a robust variance account that would record such things as the impact on the difference between actual capital expenditures to those forecast, any reduction in rate base due to asset retirements, reductions in operating and maintenance costs, difference in income and capital taxes, the difference in load growth from that forecast, and so on. A simpler approach would to be simply recalculate the CI factor on an after the fact basis, using actual values for the change in rate base and load growth and then translating the difference in the actual CI factor from that forecast into a dollar value to be either refunded or charged to ratepayers. Another simple approach would be to impose an asymmetric earnings sharing mechanism, as described earlier in this submission, on all utilities that request the inclusion of a CI factor in their price cap calculation.

h) Reporting and Data Requirements

To ensure transparency and to protect ratepayers, the utilities should be required to file their historical financial information with the Board at the same level of USoA detail as was required to be submitted in the 2006 EDR applications. In particular, The Board should provide utilities with a similar model/spreadsheet for each ear a utility is under the 2nd generation IRM so that the actual ROE could be calculated each year. Further, the Board should post this information on its website so that it is publicly and easily accessible by all.

III. IMPLEMENTATION ISSUES

a) Rate Plan Groupings

In addition to the criteria proposed by Board Staff, LPMA submits that utilities with significantly higher than historical levels of proposed capital expenditures should be required to rebase earlier rather than later.

LPMA also submits that utilities that earn in excess of their allowed ROE in 2006 should be rebased as soon as possible. Given that this information will not be available until early in 2007, it may not be possible to rebase these utilities for 2008, but they should then be scheduled for the 2009 tranche.

Finally, as noted above, utilities should be required to provide the calculation of the CI factor as soon as possible, and the Board should take this factor into consideration when determining which utilities should be allowed/required to rebase earlier than others.

b) Application of the Price Cap Index

The price cap index should be applied uniformly across all customer classes and to both the volumetric rate and the monthly fixed rate.

As noted earlier, the price cap index should not be applied to the components of rates that are essentially pass-through items, such as smart meter costs, CDM costs, regulatory assets and other similar rate adders.