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May 17, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms. Walli:

Re: EB-2010-0060 – Consultation on Distribution Revenue Decoupling - Comments of the London Property Management Association

Attached are the comments of the London Property Management Association (LPMA) with respect to the issue of revenue decoupling mechanisms. Two paper copies have been provided to the Board and an electronic version has been filed through the Board's web portal at www.errr.oeb.gov.on.ca.

Sincerely,

Randy Aiken

Randy Aiken
Aiken & Associates

CONSULTATION ON DISTRIBUTION REVENUE REQUIREMENT
EB-2010-0060

COMMENTS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

1. INTRODUCTION

By way of a letter dated March 22, 2010, the Ontario Energy Board ("Board") initiated a consultation process to examine the revenue adjustment and cost recovery mechanisms that are currently available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in the volume of energy sold.

Among other things, the Board identified amendments to the *Ontario Energy Board Act, 1998* made by the *Green Energy and Green Economy Act, 2009* that contemplate that electricity distributors will be required to achieve conservation and demand management ("CDM") targets as part of an overall policy of promoting and expanding energy conservation by all consumers.

The Board retained Pacific Economics Group Research ("PEG") to analyse the mechanisms currently available to Ontario energy distributors relative to selected alternative approaches used in different jurisdictions used to fully or partially disconnect the link between the volume of energy consumed by customers and the recovery by energy distributors of their approved revenue requirement. The report titled "Review of Distribution Revenue Decoupling Mechanisms" was filed as the first step in the consultation process.

Board staff have identified a number of questions that are relevant to the consultation, which are informed by the PEG Report and have invited interested parties to comment in writing on the questions posed and on the PEG Report. Parties were also encouraged to put forward alternative proposals or options for consideration.

These are the comments of the London Property Management Association ("LPMA") related to the questions posed by Board staff, the PEG Report and to possible alternative approaches for consideration by the Board.

2. THE PEG REPORT

a) Revenue Decoupling Approaches

The PEG Report provides a basic explanation of the three well established revenue decoupling approaches : a lost revenue adjustment mechanism ("LRAM"); decoupling true up plans (full or partial); and straight fixed variable ("SFV") pricing.

The report then goes on to highlight some of the pros and cons of each of the approaches. In particular, it highlights the administrative costs associated with LRAMs and the fact that LRAMs are not useful for reducing earnings attrition that results from declining average use that is due to external business conditions rather than utility CDM/DSM initiatives.

Decoupling true up plans can achieve revenue stability (assuming it is a full decoupling plan) but at the expense of rate stability. A partial decoupling plan suffers from the same shortfall as the LRAM approach in that it is not useful for reducing earnings attrition that results from declining average use that is due to external business conditions rather than utility CDM/DSM initiatives.

LPMA also believes that the administrative costs associated with decoupling true up plans have been underestimated in the PEG Report. The variance accounts associated with the true up plan would have to track such variances by rate class. This is because, as stated in the PEG Report, many decoupling plans exclude large volume customers. It would not be appropriate to clear variances associated with small volume customers to the large volume customers and vice-versa. However, the decoupling for the small volume customers will likely result is less risk and earnings variance from these classes of customers compared to the larger volume customers. This could mean, for example, that a lower return on equity should be used for the smaller volume classes than for the large customers as the revenue related risk associated with these customers could be substantially lower.

The variance accounts associated with true up plans have the potential to be very large in size. A recession accompanied by a warm winter and/or cool summer could result in substantial amounts being recorded in variance accounts for recovery from customers in the future. Similarly, strong economic growth accompanied by a cold winter and/or hot summer could result in a substantial amount to be rebated to customers.

The Board has experience with the customer backlash in dealing with the recovery of large variance and deferral account balances (RP-2001-0029). The annual disposition of these balances could have significant impact on customers and result in further government intervention. The Board could be required to dispose of balances on a quarterly or semi-annual basis. This would require the use of monthly average use forecasts or estimates from which the variances would be calculated rather than an annual figure. This information is currently not available with any degree of reliability from electricity distributors. The administrative costs of a more frequent disposition could also be significant.

The increased use of variance accounts also raise issues related to International Financial Reporting Standards ("IFRS") and to the Board's own view from the Natural Gas Forum (EB-2004-0213 Report dated March 30, 2005) that there should be reduced reliance on deferral and variance accounts.

Implementation of the SFV approach, while the lowest in terms of administration costs, can have significant cost consequences and cost shifting impacts on small volume customers and large volume customers. Large volume customers would tend to benefit at the expense of small volume customers within a rate class. The SFV approach can also violate the regulatory principle of cost causality in that not all distribution costs are fixed and independent of volume (kWh or m^3) or demand (kW or m^3/day).

b) Importance of Load Forecasts

The PEG Report states that decoupling true up plans and SFV pricing reduce the importance of load forecasts in rate cases and that load forecasts are the subject of considerable controversy in many proceedings. LPMA does not necessarily agree with this assumption.

LPMA believes that an accurate load forecast will still be required as long as any of the revenue requirement is recovered through a variable charge. As noted above this variable charge could be kWh or kW for electricity distributors and m^3 or m^3/day for gas distributors. Inaccurate forecasts could, in fact, exasperate the problems associated with rate stability created by decoupling true up plans. For example, a distributor may tend to over forecast volumes in order to minimize rate increases in the current year knowing that the under recovery of costs due to lower than forecast volumes will automatically take place through a rate rider or some other adjustment to future rates. However, a few years of shifting the cost burden to future rates and future customers may eventually result in customer complaints and government intervention.

Similarly, even if the revenue requirement is recovered entirely through a fixed monthly charge, there is an incentive for a distributor to over forecast volumes because the higher the volume forecast, the higher the cost of the energy, and the higher the working capital allowance component of rate base. Unless the variance account mechanism under a decoupling true up approach fully adjusts for the cost of capital associated with the volumetric forecast, ratepayers could be harmed.

Finally, an accurate volumetric forecast should be the basis the for the disposition of deferral and variance account balances.

The Board should also consider the wealth of detailed consumption data that will soon be available to distributors across the province as the result of the movement to time of use rates and the use of smart meters. This detailed information may lead to the development of more detailed and accurate forecasts and could be used to monitor the impacts of CDM and other impacts on average use. It would be a shame to not use this data to its full potential.

<u>c) 5.2 Appraising the Need for Revenue Decoupling: Gas Sector</u>

At the end of this section of the PEG Report, at 5.2.5 Appraisal, PEG provides two "small" refinements to the established approaches in the next round of incentive regulation that it says merit consideration. Each of these refinements is discussed below.

1. LRAMs could be eliminated, with the partial decoupling true up mechanisms used to address the lost margins from utility DSM plans and other sources. The economy in regulatory procedure from this step would not be large, however, unless the role of savings calculation in the shared savings mechanisms is scaled back or eliminated.

LPMA supports this refinement as practical given that both Union and Enbridge already have partial decoupling true up mechanisms in place that provide substantial protection from the financial attrition that results from declining average use. The mechanisms in place are based on normalized average use, excluding the impact of utility initiated DSM programs. The elimination of the LRAM and the replacement of the current decoupling true up mechanism with one based on normalized average use, including the impact of utility initiated DSM programs, should be easy to accomplish.

LPMA notes that the administrative savings may be minimal if the savings calculations for the shared savings mechanism is still required. On this matter, LPMA notes the current Review of Demand Side Management (DSM) Framework For Natural Gas Distributors (EB-2008-0346) in which the consultants retained by the Board (Concentric Energy Advisors, Inc.) recommend that the financial incentive mechanism be primarily tied to the success of the gas distributor in achieving pre-determined market penetration levels for each DSM technology rather than relying on savings estimates.

LPMA notes that even if the financial incentive is altered so as to not require savings estimates, the LRAM approach may still be required for the large contract rate classes. The current average use adjustments used in the incentive regulation regimes of both

Union and Enbridge are only related to residential and small volume customers. Unless an average use adjustment can be designed for the larger volume rate classes, the LRAM approach for these rate classes is likely to be maintained.

LPMA also notes that the PEG Report does not specifically address the reduction in operating risk associated with the partial true up mechanisms currently used by Union and Enbridge that effectively reduces the risk associated with declining average use for residential and small volume customers. LPMA submits that this decline in risk needs to be addressed through an adjustment to the allowed return on equity and/or the deemed capital structure. LPMA also suggests that this reduction in financing costs should be attributed solely to the customer classes that have an average use adjustment associated with them.

2. Revenue can be decoupled, additionally, from weather fluctuations. This would provide a further small simplification to regulation by reducing the role of weather normalization calculations in the decoupling true up mechanism. More important, perhaps, is its ability to foster experimentation with alternative rate designs that more effectively promote DSM goals. Customer charges can be lowered, and volumetric charges raised. The resultant increase in rate volatility can be contained by soft caps on rate adjustments without weakening performance incentives. A full decoupling true up plan would also achieve a further reduction in operating risk that reduces financing cost, and any gains can be shared with customers.

LPMA believes that this refinement is actually two refinements that should be dealt with separately. The first refinement is the move from a partial true up mechanism to a fully true up approach by shifting the operating risk associated with weather fluctuations from the distributor shareholder to the small volume customers. The second deals with the rate design experimentation and lowered customer charges in favour of higher volumetric charges.

LPMA believes that there is merit in investigating whether or not the revenue impact of weather fluctuations can or should be decoupled. While this would reduce the role of weather normalization in the calculation of the decoupling true up mechanism, it should be noted that both Union and Enbridge have a long history, unlike that of the electricity distributors, of normalizing consumption for weather.

As noted earlier, the use of a partial true up mechanism needs to be accompanied by a reduction in the allowed return on equity and or a change in the deemed capital structure to reflect the reduction in the operating risk to the distributor. Further movement to a full true up mechanism to account for the elimination of weather related revenue variances would require, in the view of LPMA, a further adjustment to the allowed return on equity and/or the deemed capital structure that was **acceptable to both the distributor and its rate payers**. This change in risk profile will also be different for different types of customers. In general, residential and small commercial and industrial customers tend be to impacted by changes in weather, whereas large industrial accounts are not. This is reflected in the fact the both Union and Enbridge normalize some rate classes for weather and do not do so for other classes. Any reduction in the cost of financing should, therefore, be directed solely to the classes of customers that would shoulder the weather risk on a going forward basis.

LPMA also notes that the magnitude of weather related risk will be different for gas distributors than it is for electricity distributors, given the substantial space hearing load for gas distributors. The level of the weather related risk will also be different among electricity distributors, reflecting that some are winter peaking utilities because of the electric space heating load, while others are summer peaking utilities, reflecting air conditioning load.

The second refinement proposed by PEG is related to rate design experimentation, including, as an example, the lowering of the fixed monthly charge and the increase of the volumetric charge. LPMA agrees that some rate design experimentation may be useful but strongly disagrees with lowering of the monthly customer charge in order to increase the volumetric charge. Not only does this increase rate instability for rate payers, but it may violate the regulatory principle of cost causation.

For the gas distributors, the variable charge should recover costs that are related to cubic metres consumed, while the monthly charge should recover costs that are independent of the amount of gas consumed. These costs are generally customer related costs and demand or capacity related costs.

While it would be optimal for a customer charge to recover the customer related costs and a demand charge to recover the capacity related costs, this is not feasible for small volume customers. Large volume customers do have capacity related charges based on costs associated with their contracted firm demand requirements. This is possible through metering that allows for the measurement of consumption on a daily basis. This is currently neither practical nor cost effective for residential and other small volume customers of gas distributors. As a result, capacity related costs are allocated to rate classes as a whole and recovered, at least in part, through the monthly charge for these customers.

As noted above LPMA does see value in some rate design experimentation. For example, inverted block structures may prove useful in promoting DSM, but such a design should only recover variable costs. A more equitable allocation of demand or capacity costs might be achieved if the number of rate classes were increased so that individual rate classes contained a more homogenous group of customers. For example, Union's M1 rate class includes residential customers that consume on average between 2,000 and 3,000 m^3 of gas per year, while at the same time including customers that consume up to 50,000 m^3 per year. It is likely that the demand or capacity on a peak day required by a residential customer is a fraction of that required by a customer consuming 10 to 20 times as much gas.

However, LPMA believes that there is less potential for rate design experimentation for the gas distributors than there is for the electricity distributors, mainly as a result of metering and resulting information differences.

d) 5.3 Appraising the Need for Decoupling: Power Distributors

At the end of this section of the PEG Report, at 5.3.5 Appraisal, PEG indicates that the current regulatory system can provide power distributors with considerable relief from the earnings attribution that can result from a worsening average use problem and that LRAMs can compensate distributors for the demonstrated lost margins that result from their CDM programs. PEG also noted that the recovery of the cost of transmission services purchased from Hydro One is already fully decoupled.

PEG states that the issue is whether other approaches to decoupling make **more** sense for power distributors than this **sensible** system going forward. The alternatives noted by PEG include the partial decoupling true up plans - the approach now used by Ontario's gas distributors - and full decoupling and SFV pricing.

LPMA recommends that, at a minimum, the Board should move the electricity distributors to the partial decoupling true up plans similar to the approach used by the gas distributors. Given the use of the price cap mechanism for electricity distributors, LPMA specifically submits that a move to the Union Gas type of partial true up is appropriate. As noted earlier, LPMA believes that the LRAM calculation for the residential and small volume customers can be eliminated through inclusion of the CDM impact being included in the normalized average use adjustment.

As this partial true up approach would eliminate a significant amount of risk associated with revenues related to volumetric charges, there would need to be a corresponding benefit to rate payers in terms of a reduction in the return on equity and/or the deemed capital structure. As is the case for the gas distributors, this reduction in the cost of capital should be allocated to the rate classes that have the average use true up and an LRAM calculation may still be required for the large customer classes that would not have an average use true up in place.

The Board may also want to seriously consider moving to a full true up approach for the electricity distributors such that the impact of weather is removed from the earnings volatility. This is a different recommendation by LPMA than for the gas distributors and is based on the fact that the vast majority of electricity distributors do not have methodologies in place to accurately estimate normalized average use. In fact, for those who do try and estimate normalized uses, the methodologies require the use of a forecasting methodology (most often a multifactor regression analysis). In other words, if a partial true up mechanism is used, normalization is required, and the normalized methodology (i.e. forecasting methodology) may be a key area of contention.

Of course, a move to a full decoupling true up adjustment would require a more significant adjustment to the return on equity and/or the deemed capital structure than would the move to a partial decoupling true up adjustment.

LPMA also submits that in return for the revenue stability for distributors that would accompany either a partial or a full decoupling true up adjustment, ratepayers would expect that a distributor would have a higher threshold test to pass if they wanted to rebase ahead of schedule (i.e. before their 3 years under IRM are complete).

In summary, LPMA generally agrees with the PEG recommendation related to the electricity distributors that the Board should give strong consideration to moving beyond LRAMs to some form of decoupling true up plan or SFV pricing.

However, LPMA again disagrees with the PEG recommendation that fixed charges be lowered and volumetric charges to be increased for the same reasons as stated earlier related to the gas distributors, assuming that the volumetric charges referred to by PEG are per kWh. If, however, the volumetric charges referred to include the introduction of demand charges on a per kW basis for residential and other small volume customers, then LPMA believes such a move should be thoroughly investigated. LPMA provides more comments on this in section 3 below in the responses to the Staff questions.

There is a significant difference between the power distributors and the gas distributors: smart meters and time of use data. In the coming years the amount of customer specific data available to power distributors will grow exponentially. This will not occur for the gas distributors. Utilization of the time of use data would allow power distributors to add a demand charge for small volume customers based on their actual usage in peak demand periods. An inverted block structure applied to the peak demand usage could be an effective tool to encourage peak shifting by all customers and reward customers who peak shift or just have low peak usage with lower distribution costs in addition to the savings from time of use rates.

3. RESPONSES TO BOARD STAFF QUESTIONS

LPMA has provided responses to the Staff questions posed but notes that the responses should not be considered to be complete at this point in time. The Board and other stakeholders simply do not have the information required to provide complete responses at this time. This information ranges from the variability of potential billing determinants for demand charges for small volume customers and the determination of what those billing determinants might be to the impact on the cost of capital of shifting the risk related to declining use due to economic and policy matters for small volume customers, shifting the risk related to use due to weather for weather sensitive customers and to shifting the business risk associated with large volume customers. As noted in section 4 below, all of these issues, and more, are intricately related. Revenue decoupling cannot, indeed should not, be done in isolation.

1. In light of developments in metering, CDM and demand side management ("DSM"), among possible others, is the implementation of further or modified revenue decoupling mechanisms for electricity and/or gas distributors warranted at this time and if so, why? For example, is the Board's current Lost Revenue Adjustment Mechanism adequate in light of the contemplated introduction of CDM targets for all electricity distributors in the Province?

LPMA believes this question needs to be answered separately for the power distributors and for the gas distributors because the developments in metering referred to are specific to the power distributors and because the gas distributors already have a form of partial decoupling in place.

a) Gas Distributors

For the gas distributors LPMA suggests that minor refinements to the partial decoupling true up adjustment could be made for those rate classes that have an average use true up. In particular, the LRAM calculations for these rate classes could be eliminated and the average use true up would be reflective of normalized average use, including the impact of DSM programs. Under this scenario, there would still need to be LRAM calculations for the large rate classes served by Union and Enbridge that do not have average use true ups.

LPMA recommends that the Board should direct the gas distributors to investigate the feasibility and appropriateness of including an average use adjustment for all rate classes as part of the next generation of IRM. This would enable Union and Enbridge to entirely eliminate the need for LRAM calculations.

LPMA recommends that the Board should indicate to the parties involved in the design of the next generation of IRM for Union and Enbridge to consider the impact on the cost of capital (i.e. return on equity and/or deemed capital structure) to reflect the reduction in the operating risk related to the use of the partial decoupling true up adjustment for the changes in average use. In addition to the magnitude of the reduction in the cost of capital, LPMA submits that there should be a discussion of the allocation of this reduction in cost to the rate classes, especially if there is an average use true up adjustment for some rate classes and not for others.

LPMA also believes that the issue of weather risk should be dealt with as part of the next generation IRM discussions. This issue would include sub-issues related to the cost of capital, the allocation of the reduced cost of capital to the various rate classes and the impact on rate stability.

At this time, LPMA does not believe that the Board and other stakeholders have sufficient information on the impact of moving from the current partial decoupling true up adjustment for average use (including DSM impacts) to a full decoupling true up adjustment that would include the impact of weather. Both Union and Enbridge are significantly impacted by variances in weather from one year to the next because of the importance of space heating in their total deliveries.

However, it is not clear, at least to LPMA, whether the weather induced variations in throughput volumes are growing, declining or remaining relatively stable as the result of DSM activities and the ongoing replacement of older heating equipment with more efficient equipment. Similarly, it is not clear to LPMA at this time what the impact on the base load of customers is as a result of DSM activities and the introduction of more efficient gas water heaters, the introduction of tankless water heaters and marketing efforts to increase other base load applications such as gas dryers and ranges. A reduction in base load relative to a reduction in heating load would mean that a greater percentage of the total throughput for some customer classes would be subject to variations in the weather. If base load is being maintained (or is increasing) relative to the decline in space heating load, then a smaller percentage of the throughput is subject to the variations in weather.

LPMA further recommends that the monthly fixed charge should continue to be increased on a gradual basis until it reaches a level that covers 100% of the fixed costs. This is in stark contrast to the PEG refinement noted earlier and is driven in large part by the need to maintain cost causality, as reflected in the response to Staff question #2 below.

b) Electricity Distributors

Turning to the electricity distributors and as noted earlier in these comments, LPMA recommends that the Board should investigate moving the electricity distributors to a partial decoupling true up plan similar to that used by Union Gas (i.e. price cap with an average use true up for the residential and other small volume rate classes). However, as also noted above, the electricity distributors do not have a history (unlike the gas distributors) of being able to accurately estimate historical normalized average use by rate class. This would be necessary to implement the Union Gas type of approach.

As a result, LPMA believes that the Board should seriously consider moving to a full decoupling true up plan that would be based on actual average use, rather than normalized actual use. To offset the potential variability in actual average use relative to normalized average use, LPMA recommends that the Board investigate whether the variance of actual average use should be from the most recent three year average of actual use (as used in the Union Gas approach, but normalized) or from a longer term average of actual use (for example, five years). The longer term average would help to smooth out variations due to weather and reduce the adjustment to future rates based on extreme weather variances in one or two recent years.

As an alternative to using a three or five year average, the Board could consider using the forecasted average use by customer class that comes out of the cost of service rebasing application. Since this is the level upon which the revenue forecast is based, this would be an appropriate fulcrum or pivot point to use in the true up adjustment variance account.

A related issue the Board would need to decide on is whether the partial or full true up adjustment based on changes in average use would be applicable only in the IRM years, or whether it would also be applicable to the cost of service rebasing year.

LPMA recommends, as it did for the gas distributors, that the Board should direct the electricity distributors to investigate the feasibility and appropriateness of including an average use adjustment for all rate classes as part of the next generation of IRM. This would enable the electricity distributors to entirely eliminate the need for any LRAM calculations.

As noted above for gas distributors, the benefit of lower operating risk to the electricity distributors would need to be accompanied by a reduction in the cost of capital for ratepayers. Again, the allocation of this cost reduction would need to be reviewed to ensure that the cost reduction only went to those ratepayers that are now shouldering the risk related to average use changes through the adjustment. Similarly, average use adjustments for large customer classes should also be investigated.

LPMA recommends that the monthly fixed charge should reflect the customer related costs and that a demand charge (per kW) based on peak demand usage be established for all rate classes that again reflects the recovery of the associated capacity related costs. This capacity related charge could be in place of or in addition to a commodity based distribution charge (per kWh), depending on whether or not there are costs that vary with kWh use. This recommendation covers all rate classes, including residential and general service < 50 kW. Further comments and recommendations related to this rate redesign have been provided in the response to Staff questions #2 and #3 below.

As has been the case for the gas distributors, changes to the level of charges should be phased in gradually to avoid rate shock, especially for low volume customers in the various rate classes.

LPMA also submits that any true up adjustment (partial or full) would need to be symmetric. If average use was higher than that used as the base for the adjustment, then the excess revenue generated would become a credit to be rebated to customers in future years.

2. What factors should be considered when assessing the suitability of Ontario's current mechanisms and of alternative approaches? Are any of these factors more or less important than others? If so, why?

LPMA has reviewed the criteria listed by PEG at Section 2.4 of the report for the selection of a decoupling plan and finds that they are mostly focused on the regulator (efficient regulation) and distributor (earnings attrition relief and removal of CDM/DSM disincentives). While these criteria have some impact on ratepayers, LPMA believes more emphasis needs to be put on the impact on ratepayers.

In particular, LPMA believes that ratepayers deserve just and reasonable rates that are both fair and equitable. To achieve such rates, LPMA submits that two key factors need to be considered above all else when considering the suitability of any alternative approaches. These key factors are cost causation and rate stability.

LPMA believes that the Board should continue to uphold the cost causation principle when it comes to cost allocation and rate design. Customer related costs should be recovered fully through a fixed customer charge. Capacity related costs should be recovered fully through a demand charge. A variable charge should recover any distribution costs that are driven by the level of kWh deliveries.

With the imminent arrival of smart meters and the related time of use data, it is submitted that electricity distributors should be taking full advantage of this information and billing all customers appropriately.

Gas distributors will not have similar information available to them, at least in the foreseeable future. As such they should continue to move to recovery of all fixed costs (customer related and capacity related) through monthly fixed charges.

Adherence to the cost causality principle when recovering different types of costs is important in that it minimizes cross subsidization between customers not only in different rate classes but also between customers in the same rate class. Similarly sized general service customers (based on monthly kWh use) can have significantly different capacity (peak demand) requirements. Even within the relatively homogenous class of residential customers there can be a significant difference in capacity requirements (peak demand use) for customers that consume the same number of kWhs on a monthly basis. These differences are driven by both the difference in the electrical equipment used and in lifestyle differences. Those customers that create more of capacity requirement should be expected to pay more and not be subsidized by those that require less.

Equally important in the view of LPMA is rate stability. Rates that gyrate significantly from year to year because of past variances in use, for example, are not likely to be acceptable to ratepayers. Rate stability is important to low income customers. It is also important to small and large businesses. It is equally important to institutional customers such as hospitals and schools.

Recovery of customer costs through a fixed charge reduces the level of the remaining costs that need to be recovered through a demand charge and a commodity based charge. This helps to reduce the amount that may need to be cleared through the true up adjustment in future rates.

Depending on the billing determinants used for the demand charge, there could be significantly less variance in the distribution revenue generated through this charge than there is currently through the variable charge for residential and small general service customers. This is an area that LPMA believes that the Board and other stakeholders should investigate as soon a reliable data is available for a sufficient period of time. An ideal demand billing determinant would be one that is stable (so as to minimize the true up adjustment) while at the same time allowing (and encouraging) customers the ability to have an impact on their costs through changes to equipment and/or lifestyle changes.

In addition to the two key factors noted above, LPMA submits that the Board needs to take into consideration customer acceptance and confusion of any alternative approaches. For example, customers are likely to be more confused and irritated when their rates go up substantially in one year because use in the previous year was lower than expected because of the weather or economic conditions or the widespread success of CDM programs. This lack of rate stability may require the Board to adopt a multiyear period to dispose of the balances in the variance account associated with the true up mechanism.

3. What, if any, are the implications of the wide-spread deployment of smart meters for the Board's approach to revenue decoupling?

As noted above, LPMA believes that the biggest implication of the wide-spread deployment of smart meters is the ability to measure and bill based on use during peak periods, effectively allowing for a capacity or demand charge to be levied on small volume customers. LPMA believes this is one the significant benefits that will be provided by smart meters.

Another significant impact related to the wide-spread deployment of smart meters is the wealth of the customer by customer detailed consumption data that distributors, the Board and other stakeholders will have access to in the near future. This data is likely to show significant differences between customers within the same rate class (for example, within the residential or GS < 50 kW classes). These differences may lead to a further refinement in rate design or even to an increase in the number of rate classes.

4. What scope for further or modified revenue decoupling might be appropriate? For example, should the impact of all variances from forecast in commodity demand be eliminated regardless of the cause (i.e., distributor-provided CDM/DSM programs, other CDM/DSM programs, the economy, weather, customer growth, etc.)? Why or why not?

The answer to this question depends whether a reduction in the cost of capital that is satisfactory to **<u>both</u>** the distributor and the ratepayers can be arrived at. Obviously, the more risk that is transferred to ratepayers, the larger the reduction in the cost of capital needs to be.

As noted elsewhere in these comments, it will be difficult for the electricity distributors to isolate and separate out the change in average use due to the weather. It would be even more difficult to isolate the change in average use due to economic conditions or who provided a CDM or DSM program.

The issue of customer growth is problematic. It may, in fact, be customer growth that is driving a significant portion of the decline in average use if it is assumed that new customers have better insulated houses and buildings are using more energy efficient equipment (see the PEG report titled "Top Down" Estimation of DSM Program Impacts on Natural Gas Usage (February, 2010) filed as part of the EB-2008-0346 proceeding at the OEB).

Customer growth may be partially responsible for the reduction in average use, but customer growth will also result in higher volumes, all else being equal.

5. Are there any alternative approaches, beyond those identified in the PEG Report, which better address revenue erosion due to changes in consumption? What are the costs, benefits and implications of implementing the alternative approach?

LPMA believes that any practical approach to addressing revenue erosion due to changes in consumption lies within the range of options described in the PEG Report that range from the LRAM adjustment at one end of the spectrum to the full SFV pricing methodology on the other.

A question that LPMA believes the Board should address is whether or not the erosion of revenues due to changes in consumption should be limited to the small volume rate classes, or whether they should encompass all customers served by a distributor.

It is also not clear to LPMA whether the Board is considering the use of revenue decoupling mechanisms for only the incentive years of a complete IRM period, or whether the true up mechanism would be equally applicable to the cost of service rebasing year. This should be clarified.

6. Is there a preferred approach (or elements of an approach) and if so, what are the important implementation matters that must be considered? What are the costs, benefits and implications of implementing the preferred approach or of refraining from doing so?

LPMA submits that the preferred approach is a cost causality based approach that recovers 100% of the customer related costs through a monthly fixed charge, 100% of the capacity related costs through a demand charge (for the electricity sector where data will be available) and 100% of the variable costs through a distribution commodity related charge. In the gas sector, the monthly fixed charge should continue to be increased so that it recovers both the customer related costs and the capacity related costs for those classes of customers where the cost of metering precludes the use of demand charges.

This recommended approach is really a mix of SFV pricing with a partial or full true up specific to the revenues recovered through the demand charge and those recovered through the variable charge. The approach minimizes the amount of revenue to be recovered through these charges where the billing determinants (kW and kWh) can vary by recovering all the customer related charges through a fixed monthly charge. Customers can have an impact on their monthly bills by consuming less and consuming less in peak periods.

The important implementation matters to be considered include education of ratepayers for the change in the method under which they would be billed; a gradual phase-in of the changes in order to avoid significant and sudden changes in the recovery of the distribution revenue requirement; and selection of an appropriate billing determinant to use for the demand charge. Ideally this billing determinant would be based on use during peak period, would be relatively stable in terms of aggregate figures to provide revenue stability for distributors, while still providing an incentive to individual customers to reduce their costs through reductions/shifting peak use. LPMA submits that the Board should consider the determination of such a billing determinant as part of the rate design process after distributors have some practical experiences with time of use data.

The costs of this approach are minimal. It will require the analysis of smart meter data in order to use a demand charge for customers where this was not previously possible. However, LPMA submits that this is one of the benefits of smart meters and should not be ignored. To do so would be to devalue the government initiate on smart meters.

There would be several benefits and implications of the preferred approach. First the principle of cost causality would be maintained and strengthened. Customers with a larger capacity or demand requirement would pay their fair share of the costs. Customers within a rate class would pay different distribution related amounts based not only on their total consumption, but also on the time of their consumption. In other words, the benefits to customers who practice load shifting and provide benefits to the distribution system are reflected in a reduction in their costs.

CDM would be enhanced. In addition to the incentive to consume less kWh's overall and less kWh's during peak periods because of the higher time of use rates, ratepayers would be further incented to reduce their peak use through the use of the demand charge based on their actual use during peak periods. This additional incentive could be increased through the use of experimental rates related to the demand charge, such as the use of inverted blocks. Experimental rates could also be used by those distributors that have a significant winter heating load to ensure that costs remain affordable to those customers.

A significant benefit, in the view of LPMA is that the recommended approach, recovers costs based on causality, encourages conservation and encourages shifting consumption out of the peak periods. Rate variability would be minimized relative to a decoupling true up mechanism that would recover some portion of fixed customer related costs through a variable charge.

In addition to the consumption/demand benefits there would be additional financial benefits (i.e. cost differential between costs during off peak and on peak periods) associated with storage/generation options that are likely to evolve over the next few years. Electric vehicles could be charged during low cost off peak periods and then supply power during peak periods. Residential solar systems would provide increased savings if the distribution capacity or demand related costs could be reduced through the use of such systems.

LPMA also notes that the use of a demand charge for small volume customers may allow distributors to recover transmission charges from these customers through a per kW charge that would more accurately reflect the cause of those costs than through the current per kWh methodology.

7. Can or should the preferred approach need to be the same in both the gas sector and the electricity sector? Why or why not? Would any other form of differentiation based, for example, on a specific distributor characteristic(s) be appropriate? If so, what might be the defining characteristic(s)?

Assuming that there is a preferred approach, it could be the same in both the gas and electricity sectors, but LPMA does not believe this is neither necessary nor desirable.

There are significant differences between the gas and electricity sectors in the province. For example, the gas sector is significantly impacted by the weather because most gas distribution customers use gas for space heating. Most electricity distributors have a relatively small weather related load in the winter (with the exception of some rural and northern distributors) while they have a much more weather sensitive load during the summer than do the gas distributors. This difference may well result in a significant difference in the weather risk that may be transferred from the distributors to the ratepayers under a full true up plan for gas distributors as compared to electricity distributors. In fact, there is likely to be a significant difference between electricity distributors in terms of the risks associated with the weather. For example, residential customers across different electricity distributors will not be weather sensitive to the same degree and the mix of customers (residential, commercial, industrial) will be different with some distributors having a large portion of their load that is not affected by weather.

In addition, as noted earlier in these comments, the gas distributors have a long history of estimating normalized gas deliveries, whereas the electricity distributors do not. This makes the use of a partial decoupling true up mechanism a practical approach in the gas sector, but more problematic in the electricity sector.

There is also an issue of whether all distributors (gas or electric) would want a lower cost of capital return in return for shifting the risk for changes (declines and increases) in average use to ratepayers. Some may want the security, others may prefer to incur the risk and a corresponding higher rate of return. Equally important is what the ratepayers want. Ratepayers may accept the additional risk associated with changes in average use (these changes could be the result of weather, CDM/DSM, economic impacts, natural conservation, etc.) if the overall reduction in rates associated with the reduction in the cost of capital associated with the risk to distributors is large enough. However, the magnitude of the decline in the cost of capital required by ratepayers may be more than the distributors are willing to give. This could be different between the gas and the electricity sector and between distributors within each sector.

LPMA is concerned that while different approaches between Union and Enbridge would be manageable because there are only two of them, there should be one common approach for all electricity distributors. If these distributors are provided with a menu of options, the Board will lose any economies of scale in terms of reducing administration costs across the sector. LPMA is also concerned that any choice of which decoupling mechanism is chosen by a distributor should not be at the expense of the ratepayers.

If the Board should allow distributors to chose their method of decoupling, if they so chose to do so, the distributors should be required to demonstrate that ratepayers will be at least no worse off under the decoupling methodology proposed by the distributor than they would be under another methodology.

4. FINAL COMMENTS

As the comments provided above and the answers provided in response to the Staff questions highlight, there is an intricate link between revenue decoupling and many other aspects of regulation including, but limited, to the following:

* Cost of Capital (return on equity/capital structure);
* Rate Design;
* Cost Allocation;
* IFRS;
* Rate Stability;
* Customer Impacts;
* CDM/DSM;
* Board Policy (eg. Natural Gas Forum);

* Principle of Cost Causality.

In addition to the above issues that are related and/or would be impacted by revenue decoupling, LPMA notes that there will be issues around any decoupling true up mechanism as to whether the true ups should be within their own rate class (as is currently the case for the Union Gas approach and for the LRAM clearances) or whether they should be spread out over all customers.

Another important issue in the view of LPMA is the timing of any changes that the Board may introduce with respect to revenue decoupling.

For the gas sector, LPMA believes that only the minor change related to the elimination of the LRAM calculation for those rate classes that have an average use true up mechanism in place should, or could, take place during the current IRM period. Any other potential change, such as a move to full decoupling for weather, should be dealt with as part of the next cost of service rebasing and next generation of IRM proposals that the gas distributors will be bringing forward in the next few years.

For the electricity sector, LPMA does not believe that any changes should be made to the distributors while they are under the current third generation IRM adjustment mechanism. As noted above, any adjustment to rate design or any implementation of a decoupling true up mechanism should be accompanied by a reduction in the cost of capital to reflect the reduced operating risk to a distributor. This would need to be taken into account in the setting of rates. The movement to the inclusion of a capacity or demand related charge, as recommended by LPMA, would also need to be based on time of use data, which is still currently in short supply for most distributors. LPMA believes that at least two years of time of use data, and preferably three, is required in order to properly analyze the data and to determine an appropriate billing determinant for the residential and GS < 50 kW classes. Following receipt of this data, the Board should initiate a review of cost allocation to reflect the available data and to "tighten up" the allocation of costs from that currently used. Resumption of the rate design initiative could then be done, using the results of the cost allocation study as the basis for the design of the next generation of rates.

LPMA believes that it would be problematic for the Board to allow any type of decoupling before it has the information it needs in order to better estimate the impact of any such decoupling.