Ontario Energy Board
26th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

BY FAX TO: 416 440 7656 (Hard and electronic copies to follow)

ATT: Mr. Peter O'Dell, Acting Board Secretary

July 12, 2004

Dear Mr. O'Dell,

2006 Electricity Distribution Rates
ECMI submission on June 16th preliminary issues list and additional items

As noted under 2006 Electricity Distribution Rates (2006 EDR) on the OEB Web page, Energy Cost Management Inc. (ECMI) hereby submits its comments with respect to issues identified on the OEB's preliminary issues list dated June 16th, 2004 and the additional items identified during the informal consultation on July 6th 2004. To say that these items are complex and broad in nature might qualify as the understatement of 2004. ECMI has attempted to comment on the items in good faith, but recognizes that volumes could be written on many of the items with no simple formulaic outcome as the conclusion.

ECMI would be prepared to participate in a working group or working groups established by the OEB to further discuss and clarify these issues. The attached comments are not exhaustive and the lack of exhaustive discussion by ECMI is in part a function of the complexity of the issues.

Originally the OEB contemplated a compressed process which would have considered cost allocation and revenue requirement issues in parallel. Now that the majority of cost allocation and a review of rate design are contemplated for 2007, this may create serious issues for some LDCs and their customers. Opportunities for offsetting synergies which might result from the two processes occurring in the same rate year may be lost. Further, even with the possibility of deferring cost allocation to 2007, dealing effectively with the issue cost allocation raises will be a time consuming process.

Failure to move forward on this item may even leave a propose implementation year of 2007 at risk.

Sincerely,

Roger White,
President.

cc Brant County Power Inc.
Clinton Power Corp.
COLLUS Power Corporation
Gravenhurst Hydro Electric Inc.
Haldimand County Hydro Inc
Hearst Power Distribution Company Limited
Peninsula West Utilities Limited
St. Thomas Energy Inc.
Wasaga Distribution Inc.

Establishing 2006 Electricity Distribution Rates
Potential Issues for Generic Methodology Review

Use of 'comparators' to assist prudency review of LDCs' costs:
1. Comparators and Cohorts
- The Board is interested in using comparators to assist in the review of LDCs' individual rate applications. Board staff would compare various operational and financial statistics between LDCs as a means of identifying outliers and anomalies. Identified anomalies would then be followed up for further explanation. The Board wants useful comparators to be identified, to the extent possible, in advance.
- What would be useful comparators to assist in expeditious processing of individual rate applications? For example: costs per customer, billing and collection expenses per customer, growth rates in certain capital and expense categories, etc.
- To further aid in the use of comparators as part of the rate application review process, can the various Ontario LDCs be grouped into a smaller number of cohorts or peers (for example, based on size, operating characteristics, structure, or operational and management processes)?
- What would stakeholders suggest be a practical segmentation of Ontario LDCs into cohorts or peer groups for reviewing 2006 rate applications?

Stakeholders are invited to suggest additions, deletions or changes to the following list at the pre-consultations. Additional issues will be added to the appropriate category (General Revenue Requirement, Rate Base, Operating Expense, or Rate Design).

ECMI Submission
Section 1
In addition to the specific items listed below under Section 2, customer and revenue mix between and within classes is fundamental to producing any valid form of cost and rate comparison.

Between classes

If an LDC serves 1/3 residential, 1/3 commercial and 1/3 industrial customers, then its rate levels and costs may be substantially different from an LDC that serves 80% residential customers, 20% commercial customers and has no industrial customers.

Within classes

If 95% in the General Service below 50kW class use less than 800 kW.h /month in one utility and 60% of the customers in the same class in another utility use in excess of 1000 kW.h/month, it would be reasonable to expect that the rates to be materially different.

The underpinning distribution systems for the different utilities fitting the scenarios above could be materially different.

As pointed out in the informal consultation, the quality of the information recorded may be different between utilities. On a customer basis, kW.h are often used as a surrogate for capacity (distribution system costs). Recognizing this, the average cost per kW.h for a given fixed distribution system (and associated costs) would decline with increased kW.h use. Hence a change in average kW.h delivered per customer for a given fixed distribution system can change materially the average cost per kWh delivered as the given fixed distribution system becomes more fully utilised or less fully utilised. (Differences in density for other categories such as density of customers /km of single phase line or density of customers/km of polyphase line can drive utilities to have materially different operating costs.)

Even if two distributors appear quite comparable on a multitude of bases, the fact that distribution systems evolve based on customer needs or demands and the evolutionary path may have followed a different time line, it may be reasonable for the two distributors to have materially different costs and rates. Electrical systems evolve as opposed to being rebuilt on an annual basis for cost optimization.

Section 2
This section may be help clarify some of the puts and takes when attempting to establish cohorts.

Introduction
In order to compare utilities, in pursuit of equity it is necessary to establish cohorts which can be compared. For the purpose of this discussion, a cohort is defined as a group of similar distributors which can be compared for regulatory purposes. The concept of a cohort presupposes that utilities can equitably be compared.

Defining cohorts (Comparable distributors)

(a) Bands
For example, utilities might be divided into bands on the basis of one criterion such as the number of customers, say, from zero to 5000 customers. While this approach may be useful for comparisons for computer system costs, the same approach is not automatically transferable to Service Quality Indices.

(b) Other
Multiple criteria could be applied to define cohorts and a weighting factor might be applied to each. For example if the only two influencing criteria were the number of customers and the voltage, an equation could be developed to normalize the data. That is, the utility’s data would be multiplied by a factor which would make it comparable to a normalized standard. For example, if the customer counts in the utility were identical to the “normal” standard, then the normalization factor on the customer count would be unity. If the normalized voltage were 27.6 / 16 kV and a utility operates a system at 13.8/8kV, the

normalization factor for the voltage component of the equation might be 27.6 divided by 13.8. This division, while precisely correct is totally useless and demonstrates the difficulty in trying to establish comparability using simple factors. Any adjustment factor would have to consider the impact on the utility's capital and operating costs at different voltages and precisely quantify it. The operating costs and capital cost of the system as well as the reasonable time required to do maintenance on systems of different voltages are not dependent exclusively on the difference in voltage.

The difference between operating and capital costs is not a linear function dependent exclusively on the operating voltage. For example, whether the system is overhead or underground will have material influence on both the capital and operating costs. (Underground maintenance is generally less frequent but more expensive when it occurs than overhead. Certainly on a capital basis, underground is more expensive).

Materially differentiating characteristics

1.Operating voltages configurations

Possible voltages of an LDC's 3 wire Low Voltage (LV) system*	Possible voltages of an LDC's 4 wire distribution system -
44kV	27.6/16kV
27.6kV (3 wire)	25kV/12kV
	13/8.8kV
	12/7kV
	4160V/2400V

* Note that an LDC may not operate an LV system. An LDC's overall system can contain any combination of these distribution and/or LV configurations. The capital cost to install systems of different voltages can be materially different. Once in service, the operating costs of systems at different voltages can be materially different.

2. Utility / Customer transformation responsibilities

Utility - Where does the utility responsibility start and end?
LDC's vary widely in their transformation ownership and operating responsibilities. Those responsibilities are dependent on the portions of the system for which the LDC is responsible for the control, management and ownership of the system. The responsibilities end when the LDC's customer assumes control, management and ownership of its system. Transformation responsibilities can occur in the following 3 areas.

1. An LDC can own and operate it own Transformer Station (TS) supplied at 230kV

or 115kV.
2. An LDC can own and operate its own Distribution Stations (DS's) supplied at 44kV or 27.6kV.
3. An LDC can own and operate its own distribution transformers.

Where does the customer responsibility start?
An LDC may require a customer to own transformers above a certain size where those transformers are dedicated to individual customers. For example, an LDC may not supply distribution transformation that supplies an individual customer larger than 350kVA. In this case the individual customer assumes the responsibility of the performance of the transformer and failure of a customer owned transformer will not cause the utility to incur operating costs.

3. Overhead vs. underground supply

As previously discussed, whether the system is overhead or underground will have material impact on the utility's capital and operating costs.

4. Nature of the environment factors

- Geographic Weather patterns, such as lightning storms (e.g. Muskoka lightning corridor), freezing rain and tornadoes etc.
- Vegetation, such as encroachment by trees on power lines.
- Distribution system corridors (along roadways or through the bush).
- Soil conditions (rock versus sand)

Impact of Nature of the environment
The nature of the environment can impact capital and operating costs. Each of the above categories can change utility's construction standards and the associated capital costs and operating costs resulting from weather patterns, vegetation, access to distribution corridors and soil conditions.

5. Historical influences

Historical influences can include the evolution of different distribution voltages within a utility and in fact the evolution of the entire distribution system. These influences can include political decisions where isolated or adjacent political communities or distribution systems have been merged to be served by one distributor. Age of system may be a primary differentiation between systems. For example, some systems may be all underground.

6. Geographical Area
Uniform or non-uniform distribution of customers on the system. For example, pockets of high system density and long expanses of lower customer density is not a uniform system

7. Other disparity Factors

Utilities will have inherent disparity factors such as: -

- Customers / km (Density. It may be appropriate to consider utility's capital and operating costs on a customer class basis if density is the differentiating criteria between the classes)
- Customers per sq. km. (Served area, where served area is the qualifying area for lays along lines in square km as defined in the Distribution System Code).
- Utility Size.
- Number of customers.

An alternative to using absolute standards against imperfect cohorts

From a regulatory perspective, a perfect world might be one where all LDC's would be identical. On the basis of that equality, it would be reasonable to expect all LDC's to have similar operating costs, rate bases and risk premiums. This is not the case. As demonstrated above, it is reasonable to expect different capital and operating costs for different utilities, even though each of the utilities may be applying best utility practices.

As the equitable definition of cohorts is difficult if not impossible to achieve, ECMI suggests that bands of cohorts, based on similar influences as described above, be established. Certain characteristics may dominate the capital side of a utility, while others or the same ones may dominate the operating cost side of the utility. Each of the numbered 7 points above under Section 2 must be considered in the context of Section 1 also above.

Each utility is granted a return on its rate base. A rate base investment by a utility reflects its unique operating characteristics and operating environment. Further, it is the investment in the current system that an LDC's customers are paying for through existing approved rates.

Revenue Requirement - General Issues:
2. Test Year for establishing Rate Base / Revenue Requirement
- Merits of historical versus forward/future test year (or combination thereof).
- Should one approach apply to all LDCs?
- Preferred choice for a specific past test year.

ECMI Submission

There are advantages and disadvantages associated with both historic and future test year approaches. The use of historic test year has the advantage of dealing with hard numbers but relies on dated information. The use of a future test year may be the best approach if the LDC is predicting lumpy capital or operating expenses, such as a new Distribution Station (DS) or the replacement of major assets at the end of their unnatural life. There may be problems associated with the time delay of incorporating lumpy capital into the rate base in a time frame that manages rate shock.

3. Load Forecast
- If using a forward test year, acceptable methodologies to be used for the load forecast employed for determining the revenue requirement.

ECMI Submission
See response to Issue 2

4. Test Year Adjustments
- What types of adjustments in historical or future test year data might be allowable (for example, for anomalies or for known and measurable changes that are expected to persist)? What should be provided in support of proposed adjustments?

ECMI Submission
See response to issue 2

5. Weather Normalization
- Is there a need for weather normalization, of future test year data, in the electricity sector?
- If yes, then what methodology or methodologies would be appropriate for weather normalization in Ontario?
- Should the allowed ROE be reduced if utilities no longer face weather-related risks?

ECMI Submission

The issue of weather normalization in terms of load forecasting should not be delinked from the concept of normalizing revenue statistics. The notion that a change in load (energy) forecast produces a proportional change in revenue assumes a decline or increase in the number of customers proportional to the decline or increase in load (energy). Further, stability and correlation between load and energy use increase or decrease in the electricity industry has not been addressed historically in the Ontario market in the face of huge increases in the cost of power (commodity). Elasticity in energy use may be greater than anticipated in the present environment compared to that previously experienced in the electricity market and there is no reason to assume that the customer response will be linear. Customers may perceive their only option to deal with a change in electricity price is to make capital investments such as fuel substitution or improved home insulation to reduce energy consumption. This response may produce a lag or, depending on DSM programs, a lead in the customer price response. The customer required response contemplated by current government policy will at the very least increase forecasting risk and potential shift in customer use patterns. The elimination of coal-fired generation in the absence of a timely replacement generation will produce huge energy price spikes or rotating load cuts. If a 20% reduction in energy use in all three sectors (residential, commercial and industrial through DSM, this will require a huge systemic change in lifestyle, work style and construction standards and competitiveness of the Ontario marketplace.

The error introduced into the forecast by these factors will swamp any error introduced by failing to weather normalize the data based on a 30-year period. Any normalization should be done on a 3 to 5 year period basis only.

Weather normalization has historically been used in the Ontario market to capture variances during to cold weather temperature changes and heating load. Substantive increases in the market penetration by both central air conditioning units and window air conditioning units may make all but the most recent energy use patterns less than relevant as Ontario moves to a summer peaking utility.

6. (Maximum) Return on Equity for 2006 Electricity Distribution Rates
- The current formula is based on the same approach as used in the natural gas sector, but with a separate multi-year forecast of interest rates.
- Results of application of current formula in light of current interest rates.
- Bearing in mind the Board's recent decision on the generic ROE for Ontario gas distributors (RP-2002-0158), are there any adjustments to the electricity distribution ROE formula that warrant serious consideration?
- What economic estimates should be used in the ROE formula (e.g. annual vs. multi-year forecasts of long-term Canadian bond interest rates)?

ECMI Submission

If a multi-year PBR program is being considered, it may be appropriate to consider a multi-year forecast program for the cost of risk-free long-term debt. With the volatility in the marketplace it may be less appropriate to consider both a long term PBR program and a multi-year forecast approach to risk free long term debt.

7. Debt/Equity Structure
- Are the current deemed D/E structure(s) still appropriate? If not, what other common approach may be more suitable?
- Merits of using actual utility-specific D/E, in lieu of a deemed D/E, when setting rates.

ECMI Submission

Forcing all LDC's to an actual uniform capital structure smacks of micro management. If an LDC borrows largely for acquisitions or lumpy capital expenditures, its customers should not automatically reap the benefit of lower debt cost or face the punishment of higher debt costs. The use of a deemed capital structure continues to be appropriate.

8. Debt Rate / Cost of Capital
- The current deemed Debt Rates were based on a forecast of long-term Canadian bond rates, and were adjusted based on utility size.
- Update of Debt Rate(s) to reflect current economic conditions and interest rates.
- Debt Rate(s) to be uniform, size-related, based on ability to borrow, or other?

ECMI Submission

A deemed cost of debt is appropriate unless the utility can demonstrate at a point in time that the embedded real debt cost is higher or lower than the deemed debt cost. If a deemed debt cost is used by the regulator, then the return which includes the risk premium for the shareholder should continue to be based on the current cost of long term risk free debt plus a debt premium plus an equity risk premium, regardless of the utility's actual cost of debt. Hence, the return on equity should be sufficient to retain shareholder investment in the utility.

9. Depreciation Rates
- Depreciation rates set out in Distribution Rates Handbook were carried over from the former regulator.
- Appropriate time to undertake a full-scale review of depreciation rates?
- Stakeholder views on a limited review of depreciation in 2006, such as: amortization of select assets, salvage valuation, asset verification studies, or updating technical inputs (e.g. composite service life statistics).
- Merits of true-up provision requiring differences between theoretical depreciation and booked depreciation in excess of a specific percentage to be amortized over the remaining life of the asset.

ECMI Submission

If depreciation schedules need to be revisited, that revisit should occur at the same time as any adjustment in the rate base to take full advantage of any synergy opportunities and thereby reduce customer impacts.

10. Transfer Pricing and Shared Corporate Services
- What method(s) will be acceptable for rate purposes when allocating the cost of shared corporate services to the regulated utility?
- How to review prudency of expenses paid for services outsourced to affiliates (or non-affiliates)?

ECMI Submission

One approach to considering transfer pricing is not sufficient. Cost plus, fixed price or other basis of transfer pricing conditions may each require a discrete regulatory approach. The OEB ‘s assessment of the prudency of the transfer price needs to consider the specifics of the contractual arrangements between the parties.

All contracts with affiliates or others, must be considered on a materiality basis as well as what opportunities exist in the marketplace and value for money concepts. Universal formulas like dollars per customer may have to be considered in the concept of scale. When considering utility scale, the overall impact on the utility’s customers may result from benefits in some areas through lower costs that offset higher costs in some areas, all considered under the concept of overall service.

11. Low Voltage and Wheeling Costs
- Host distributors are presently providing low voltage and wheeling services, but without recovery in rates.
- Treatment in 2006 revenue requirement of Low Voltage charges embedded distributors incur and will pass through to their customers.

ECMI Submission

With respect to wheeling charges and assets used by 3rd parties other than distributor’s customers, the costs of providing these services should, where material, be tracked to ensure that distribution customers are treated fairly.

The question of double billing of transmission charges was raised in the informal consultation sessions. This issue continues to be problematic for embedded LDC’s with optional multiple delivery points. The IeMO seems reluctant to address this issue, even when Hydro One and the embedded distributor have agreed on a method of doing so. The OEB’s assistance in dealing with the IeMO and the ultimate resolution of this would be appreciated.

12. 2006 Taxes / PILs
- A fair and practical methodology for calculating an allowance for taxes / PILs in 2006 rates.
- Merits of the use of actual versus deemed figures in regulatory tax calculation.
- How to confirm whether LDCs are maximizing tax deductions?
- Impact of any expected changes in 2006 tax rates or rules.
- Relevance of discussions in other Canadian jurisdictions on approaches to tax calculation (e.g. use of “flow through” method).
- “True-up” of historical PILs (2005 or before) will be addressed separately.
- Whether taxes should be inside or outside a future PBR envelope, as well

as appropriate sharing of benefits of tax planning, will be addressed later.

ECMI Submission

Traditionally the regulator has stayed out of the tax initiatives imposed by government through such vehicles as deferred taxes. It is recognised that any PILs recovery allowed in the rates should reasonably reflect the underpinning tax structure. Actual tax considerations may be appropriate as a short term initiative during transition, but unless the initiatives are industry specific, it is probably inappropriate to consider actual taxes in the long term. Bumps in utility cost which result in lower taxes because of lower net income may make the consideration of actual taxes inappropriate. If the use of actual taxes approach was adopted, then the risk premium commensurate with that change would have to be increased on a downside risk basis, due to the elimination of the partial offset to downside risk created by the deemed PILs adder. On an upside risk basis, tax considerations may produce incremental investments in either OM & A or capital which benefit the customers. This may provide its own prudency checks without the regulator's specific intervention. Any true up of deemed PILs should be done outside the PBR regime, so that the PBR base is not distorted. If lumpy rate base adjustments (capital expenditures or related activities) are made, there may be justification for mid PBR adjustments to the rate base.

Distribution Rate Base Issues:
13. Definition of Distribution Rate Base
- The Distribution Rate Handbook lists what assets and accounts should be included in the distribution rate base, but there have been some changes to the Uniform System of Accounts over time.
- Are there assets for which the classification should be clarified or changed (e.g. treatment of >50 kW transformer assets)?
- For assets that are shared between distributors, or assets shared between distribution and non-utility functions, should specific methods be approved for apportioning the appropriate amount to the distribution rate base?

ECMI Submission

In general, all the issues that appear in this issues list, as well as any others that impact on the rate base should be considered at the same time. If, in the pursuit of equity, the regulator considers it appropriate for the distributor to continue to pay a transformer ownership allowance to customers that own, operate and maintain their own transformation supplied at primary voltage, then before the cost allocation process is performed, Operations, Maintenance and Administration (OM &A) costs and/or assets should be adjusted to provide the distributor with the revenue required to permit the payment of transformer ownership allowances.

The alternative may be the prospect of installing delivery voltage sensitive rates, particularly within the General Service class.

14. Rate Base Measurement Date(s)
- Electricity distributors have historically reported data for RRR and rate application filings for the calendar year, while the "rate year" for 2006 is presumed to be May 1, 2006 to April 30, 2007.
- What approach should be adopted for dealing with the timing difference between the calendar (report) year and the rate year?
- What approach should be take towards valuing the rate base over a 12 month period (average of monthly values, averaging of start and end dates values, end of period value)?

ECMI Submission

Adjustments in the fiscal year should be considered with extreme caution and done in such as way that any shift does not disadvantage any return earned by the distributor.

15. Working Capital Component of Rate Base
- The previous working capital allowance (WCA) was based on a formula originating when Ontario Hydro regulated the industry and consisted of 15% of controllable costs plus the Cost of Power.
- Should a common WCA formula continue to be used? How should it be updated in light of subsequent industry restructuring and rate unbundling?
- Should some LDCs be required to conduct lead-lag studies to empirically establish their working capital requirements? Could the results of these studies be extended to other LDCs? Should any LDC requesting a WCA greater than that provided by the new formula be required to file a lead-lag

study?

ECMI Submission

Delays in the billing associated with the introduction of the commodity market produce a real and material cost to the distributor. These costs should be included in the rate base working capital allowance. Hence, the present 15% working capital allowance is probably no longer adequate.

16. Capitalizing Expenses
- Reasonableness of a LDC's policy regarding capitalization of expenses.
- Consistency between utilities.
- Significance of accounting debates over the merits of incremental vs. full cost approaches towards capitalizing overhead or indirect costs.

ECMI Submission

When considering capitalization expenses, the electricity industry is materially different from the gas industry due to the obligation to serve. The interplay between the economic evaluation model, conditions of service, system reliability and actual capital expenses faced by the LDC are important. Capitalization policies related to administration costs and interest expense may be materially different if the capital work is externally sourced or internally constructed. Again, one shoe fits all is not the appropriate approach.

Trends lines on capital projects may provide a first pass measure with lumpy capital expenditures providing specific review all in the context of the above comments. Trend lines based on consideration such as dollars per customer are probably less than appropriate in the context of a uniform approach for all LDCs. These trends lines should be utility specific, considered in the context above and our comments on comparability in Issue 1.

The pre-2000 Contributed Capital was accepted for inclusion in the rate base by the OEB in part of its PBR decisions. Consideration of a separate return for these items is not appropriate.

17. Capital Projects
- How should the prudency of capital expenditures be reviewed?
- Merits of project-by-project review versus use of trendlines.
- What level of review is appropriate for major projects? Are there filing requirements that can assist review?
- Establishing a fair trendline in light of historical trends and planned new investments.

ECMI Submission

See response to Issue 16

18. Contributed Capital
- Distributors are presently allowed to earn a return only on pre-2000 contributed capital, and until such assets are fully depreciated.
- Prudency review to check that the appropriate amount of contributed

capital is allowed to earn a return.

ECMI Submission

See response to Issue 17

19. No-Cost Capital

- Extent of application of "no-cost" capital concept to Ontario electricity distributors. What specific items should be included (e.g. pension assets)?

ECMI Submission

ECMI agrees that this item is significant and should be considered on an individual LDC basis only where amounts are material.

20. Rate-Setting Treatment of Capital Gains

- Should a uniform approach be followed for distributing gains from sale of utility assets between shareholders and ratepayers?

- Would the same approach apply to sale of shares?

ECMI Submission

If it can be demonstrated that the sale of assets is de facto asset stripping of the LDC, it may be appropriate to consider some recognition of capital gains. It must also be recognised that other assets not fundamental to the direct delivery of power and energy by the LDC represent an investment by the shareholder with the commensurate risk and benefits associated thereto and should not be considered from a capital gains or loss perspective. The exception to this may result from situations where government or regulatory policy or societal structural change in terms of safety, environmental or other operating considerations result in the need to replace assets prematurely with the corresponding capital loss. It may be appropriate for the capital loss to be shared between the customers the shareholder, or distributed amongst the customers, depending on such considerations as the reasonable prudence of the original investment. With respect to the sale of shares in a fair market there should be no consideration of capital gains. However, sale of shares to directors officers or other employees at less than fair market value may warrant capital gains considerations, but the question of whether this is a regulatory consideration or a Securities Commission issue is also of interest.

Operating Expense Issues:

21. Distribution "Wires Only" Expenses
- The Distribution Rate Handbook lists various utility and non-utility expenses (and revenues), but there have been subsequent changes to the Uniform System of Accounts.
- Does the classification of any item(s) need to be clarified or changed?

ECMI Submission

Yes, clarifications may help. Committees may provide an effective vehicle for dealing with this item.

22. Post-Retirement Benefits and Pensions
- Review of economic assumptions used in plan calculations.
- What pension costs are allowed into the distribution revenue requirement (e.g. treatment of a pension surplus, shortfall or contribution holiday; valuation measures to reduce volatility)?
- Must an LDC move to the accrual method of accounting for post-retirement benefits for rate setting purposes, in light of CICA s. 3461?
- If an LDC changes from the cash to the accrual method, regulatory amortization of one-time expense as a result of the change-over.
- Prudency of management of pension assets.

ECMI Submission

ECMI agrees that pension and other separation costs are important but consideration should be on a utility specific basis only if decisions regarding these matters are not arm's length, and also giving due consideration to materiality.

23. Site Restoration and Removal Costs
- For any LDCs to which this applies, what are the rate-setting impacts of compliance with new CICA s. 3110 (effective 2004).

ECMI Submission

ECMI has no comment on this issue at this time. It is possible that a utility specific issue may warrant a utility specific response at a later date.

24. Insurance Expense
- Determination of appropriate reserves for distributors that self-insure, or appropriate insurance expenses for distributors that use insurers.

ECMI Submission

The insurance cooperative collectively captures the risk faced by the industry. As the insurer is a cooperative rather than a private investment organisation at arms length from LDC's the shareholder neither wins nor loses from its existence.

25. Bad Debt Expense
- What is an appropriate amount for uncollectibles, especially considering interaction with other policies (such as the LDC's Security Deposit policy)?
- Should a single method be used to calculate the amount? If so, how should it be determined?

ECMI Submission

As the OEB has prescribed the Security Deposit policy for LDC's, it is inappropriate to further expose the LDC. Going forward a utility's bad debt exposure has increased and adjustments to expected net income should be incorporated to reflect this increased exposure.

26. Employee Compensation and Staffing
- Review of reasonableness of total executive compensation (base, incentive plans, and supplemental income and benefits). Review of the distribution of the costs of the incentive plans and supplemental income between shareholders and ratepayers (for example, based on who receives the benefits from achievement of corporate targets). Review of allocation of executive salaries within a corporate group.
- Merits of a uniform approach in respect of regulatory review of bonuses (such as dividing costs 50/50 between shareholders and ratepayers) versus a case-by-case review of the terms of each incentive plan.
- Review of reasonableness of non-management labour costs.

ECMI Submission

Compensation and staffing considerations should be considered by the regulator only on an aggregate basis. Employee compensation and staffing should be considered within the whole utility only.

Consideration of bonuses and possibly some other specific items should be considered on a materiality basis only. Where the regulatory burden associated with these items exceeds the costs and benefits that flow from these items it is questionable whether the customers are well served by the process.

27. IT Costs
- Review of prudency of IT costs, including treatment of IT outsourcing costs and of IT project cost overruns.

ECMI Submission

When considering IT costs, the utility scale has to be considered. The overall impact on the utility's customers may result from benefits in some areas through lower costs that offset higher costs in some areas, all considered under the concept of overall service. As indicated in the response to Issue 26, the aggregate OM & A costs may be the most effective way of evaluating the impact on customers, while at the same time avoiding regulatory micro-management of LDC operations.

28. Advertising, Entertainment, Charitable/Political Contributions, Employee Dues, Research & Development
- What is an appropriate regulatory treatment of expenditures that may benefit the ratepayers only partially?

ECMI Submission

Consideration of these expenses and should be considered on a materiality basis only. Where the regulatory burden associated with these items exceeds the costs and benefits that flow from these items, it is questionable whether the customers are well served by the process.

2006 Rate Design Matters:
Board staff propose that certain rate design issues, discussed below, be addressed as part of setting 2006 distribution rates. Hence, these issues would be examined as part of the fall 2004 generic process. Stakeholder views on inclusions or deletions from this list are sought.

It is proposed that further rate design issues be addressed after the updated cost allocations results become available, as part of the process for establishing 2007 distribution rates.

While the treatment of Demand-Side Management / demand response initiatives is recognized as potentially impacting on the setting of 2006 distribution rates, it may be expected that the treatment is better dealt with outside of this generic process. The same approach is also expected with respect to any new treatment of the distribution loss factor.

Rate treatment of smart metering initiatives for large consumers may be addressed in the generic process. The need for and design of Time-of-Use distribution rates and their effectiveness in encouraging load shifting are also of interest to the Board. Stakeholders' perspectives on these possible inclusions or exclusions are sought at the July consultation.

The future commodity pricing mechanism under development may have an impact upon 2006 rates, and it is expected this will be dealt with when the applications are filed in mid-2005.

29. Specific Service Charges
- Specific Service Charges are to be considered as part of establishing the 2006 revenue requirement.
- Will also address variability in types and charges for Specific Service Charges across all distributors, with an aim of exploring consistency in definition and application. For example, should there be a single charge for each service across Ontario?

ECMI Submission

The notion of standardizing service charges or the introduction of standard service charges by some distributors may encroach on the cost allocation process. Resultant changes in service charges may not be cost effective for smaller distributors. If the utility spends $1,000 chasing a nickel, neither ratepayers nor shareholders may be well served by the process. Service charges have a significant interplay with the Conditions of Supply and should also be considered in this broader context.

A single charge for each service across Ontario may not be credible when viewed in the context of cost causality. Density considerations for reconnection and soil conditions for pole relocation are only 2 examples of some of the material risks imposed on distributors by de-linking cost causality from price signals to customers.

If the utility wishes to charge for a particular service, then consistency in definition and application may be appropriate, providing all the cost causality considerations are considered.

30. Unmetered Scattered Load
- Definition and rate treatment of Unmetered Scattered Load (cable TV, payphones, advertising, etc.).

ECMI Submission

The notion of bundling all unmetered scattered loads together is inappropriate. The handling of fixed loads should be separated from variable loads when considering this option. To the extent that the customer has the ability to modify the load by changing energy use through the addition of such items as amplifiers or technological change in the use of the power and energy in advertising signs, installation heaters, or modifying illumination demands, makes monitoring these non-fixed loads both costly and essential. The pre-unbundling treatment of one connection equals one service and the associated general service rates apply to each service independently continues to be appropriate.

The fact that billing in some cases may be aggregated for the convenience of the customer it could be argued that this aggregated bill should probably result in an increased charge to that customer on the basis of cost causality, rather than the dropping of one service charge per connection as suggested by some.

Any understatement of the unmetered energy use is allocated to losses which are paid for by the other customers

31. Time-of-Use Rates
- Even prior to completing new cost allocation studies, the merits of integrating the former TOU distribution rate classes that appear in the tariffs for various LDCs into more appropriate rate classes.
- Design of Time-of-Use rates for large consumers to encourage load-shifting.

ECMI Submission

ECMI supports the integration of Time of Use and Interval Metered classifications into one class, subject to customer impact considerations.

50kW Threshold Class Boundary

The over 50kW/under 50kW boundary is an issue for customers. Reintegration of the over 50kW and under 50kW customers into one class can eliminate the equity issue currently existing at that boundary.

The 50kW threshold **within** the regular general service customer group historically existed on the basis that individual customers below 50kW were similar to residential customers from a distribution perspective and customers in excess of 50kW were often supplied from polyphase supply systems and required special metering (instrument transformers). At that point the capacity component of the delivery system becomes a significant cost driver and demand charges were introduced to recover both generation and distribution capacity costs. With the disaggregation of commodity from distribution, the decision to create a 50kW class boundary has created an artificial step for a customer with a change in use level and current rate structures do not provide a smooth transition. That fact was recognised by the OEB in its September 29, 2000 decision which dealt in part with the unbundling of rates.

What may be less apparent is the fact that this same artificial step at the 50kW boundary creates equity issues for customers who are close to the boundary. An artificial boundary used to establish a non integrated separate class creates an **equity** issue (equal treatment of equals) as two customers one at 49 kW and another customer at 51 kW using the same amount of energy would generally be supplied from similar if not identical distribution facilities. To have materially different distribution charges for these essentially equal customers does not produce **equity**. These equity issues should be considered at all boundary points established for essentially similar if not equal customers. Differentiating characteristics between classes (defining characteristics of classes) must not only be clear but must be seen to be fair, equitable and reasonable.

Cost Tracking and Twelve Month Demand Averaging

It has been suggested that using a twelve-month rolling average of the customer's demand is an effective mitigation strategy. While this may solve the price problem for some customers by reclassifying them as below 50kW customers, it simply moves the boundary closer to other customers. Further, this solution diminishes the distribution system cost tracking need identified by OEB staff who during the initial rate unbundling process. OEB staff stated that if a customer periodically exceeds 50 kW the distribution system facilities must be constructed with the capacity to meet that demand. The fundamental problem is the establishment of separate under 50kW and over 50kW customer classes without addressing the rate design and associated customer price impacts. These boundary issues create the perceived and real inequity.

It has been suggested by some that requiring interval metering down to the 50kW level will resolve this issue. This fails to recognise that the interval meter deals with the commodity costs very effectively, but does not change the equity issue dealing with distribution system costs and rates marginally above or below the 50kW level. The costs of serving a 49kW customer using 25,000 kW.h of energy use is similar if not identical to the cost of serving a 51kW customer with 25,000 kW.h of energy use.

The question of integrating all the over 50kW customers, based on the possible (probable?) acceleration of the introduction of interval meters for these customers may produce a benefit, particularly if the cost of processing interval metered data were split out as a customer service charge.

Discrimination
The OEB, like its predecessor Ontario Hydro, identified discrimination as a fundamental classification issue. Customers within the same class should not be treated differently. If subclasses are created without proper differentiation and understandable definitions, which are readily defended in a public forum, the credibility of the regulatory process could well be undermined.

Single Phase versus Three-Phase Supply
It is probable that separation of customers on the basis of single phase vs. polyphase is more appropriate than under and over 50kW. This classification approach is currently used by Hydro One. The counter argument is that the utility decides whether the load has to be supplied as a single-phase load or polyphase load and therefore the 50kW boundary may be more appropriate.

The decision by the utility to install single or polyphase supply depends, among other things on the availability of supply near the customer. A utility may potentially make uneconomic decisions precipitated by a single vs. polyphase decision. There are finite limits to single-phase capacity. If a customer has a motor of a certain size, it may be normal to use polyphase supply. If a utility has single phase supply available, a utility may be able to install add-a-phase equipment and avoid a potentially huge capital contribution by the customer to provide a polyphase supply. There are limits as to what size motors can be put on any system and those limits are a function of the available short circuit.

Possible Solution to the 50 kW boundary issue
One possible solution to the boundary issues surrounding the separation of the 50kW customers into a separate class is to remerge the over 50kW and under 50kW classes

into one general service class with a block pricing structure where all customers would pay a common service charge (with possible adders for polyphase and/or interval metered customers). Similarly all customers would face a two-part volumetric distribution charge. The first charge would apply to all kW.h up to 12,500 kW.h (250 hours use at 50kW) and secondly a volumetric demand charge applying to all kW in excess of 50kW. This would create a smooth transition for low load factor or high load factor customers around the 50kW boundary. It also has the advantage that high load factor customers approaching the 50kW boundary would drop the volumetric distribution charge per kW.h to reflect the high load factor (higher system utilization factor) benefits brought to the system.

A similar approach could/should be considered to address boundary issues for the boundary between the general service class and the intermediate use class or the boundary between the general service class and the large use class. This could be accomplished by shedding the initial kW.h volumetric charge for the intermediate or large use class and reducing the demand charge for the intermediate or large use class to close on the revenue requirement for the intermediate or large use class. This closure on the revenue requirement could become a more challenging issue because the revenue requirement for the intermediate or large use class involved is determined independently.

Design of Time of Use (distribution) **Rates for large consumers**
The introduction of new customer classes could be considered as an alternative to or in conjunction with interval metered pricing but any time of use distribution rates introduced by LDCs should be implemented based on savings to the capital and operating cost of the distribution system. These distribution system costs savings would be most secure if tied to a controlled load situation. Failure to make that link could result in a reduction in the security of the distribution system which could further compound the already existing insecurity on the supply side. The introduction of such a class might best be done on a customer option basis.

32. Fixed/Variable
- In advance of new cost allocation studies, it may be desirable to start addressing some of the variability in the fixed (Monthly Service Charge) and variable (demand/energy-related) tariffs across the province.
- Should there be partial movement towards a uniform fixed charge for each rate class across Ontario in 2006?

ECMI Submission

Residential Class

When Hydro One's rural system is considered, the separately metered residential class customers were further differentiated on the basis of two criteria; density and methods of use. Density criteria recognise the cost causality of individual customers based, in part, on number of customers per km of primary line. In order of descending density these classes were: -

- Urban - the densest and often found in municipal settings.
- High density
- Suburban (normal density for the rural system)

The latter two categories, high density and suburban, are historically further differentiated on the basis of method of use, that is,

- Year round

and

- Intermittent occupancy (Seasonal)

From a distribution system perspective, separation of customers between classes for the residential customers is generally appropriate only when a significant (material) number of customers reside in each class or such other material differentiation like time-of-use is a factor. Historically, the materiality threshold has been 10%. That is, 10% or more of the customers within a class have materially different character (e.g. cost of supply facilities… density) than other customers within the particular class.

A significant driver for differentiating customers within a class occurs when the use pattern is substantially different between customers who would otherwise have the same classification. Historically, the residential seasonal customers typically use in the order of 40-60% of the energy typically used by year round customers. From a distribution system perspective, the peak demand (which establishes the distribution system capital requirements) for the year round customers and the seasonal customers are often similar. Therefore, from a cost causality perspective, the distributor incurs similar cost in supplying the seasonal customer and the year round customer.

Scenario (credible assumptions for illustration purposes)

- A Suburban seasonal customer has an average 12 month consumption of 500kW.h
- A Suburban year round customer has average monthly consumption of

1000 kW.h.

- Distribution costs to supply a suburban residential customer is $360/year.

If 50% of the revenue requirement was in the monthly service charge, then the service charge for both the year round and seasonal customers would be $15/month. However, in order to cover the remaining distribution costs, the commodity rates for the seasonal customer would be 3.0 cents/kW.h and 1.5 cents/kW.h for the year round customer. If the classes were merged, then the variable rate would be 2.25 cents/kW.h. That would mean the year round customers would be subsidizing the seasonal customers to the tune of $7.50/month (0.75cents /kW.h times 1000 kW.h) or $90/annum.

Consider the following probable scenarios: -
Scenario A

1. Average consumption is materially different between classes based on selected class definitions
2. A fixed percentage of fixed charge is used
3. The selected percentage of fixed charge is low
4. The fixed charge seeks to recover avoided costs where avoided cost might be defined as meter reading, billing and collecting.

In this situation, then the variable component for classes with low consumption and say lower density would be relatively high and the resultant price on the higher consuming customers in that class would be huge.

Scenario B

1. Average consumption is materially different between classes based on selected class definitions
2. A fixed percentage of fixed charge is used
3. The selected percentage of fixed charge is high
4. The fixed charge seeks to recover avoided costs where avoided cost might be defined as distribution costs (sunk costs).

In this situation, then the variable component for classes with low consumption and say lower density would be relatively low and the resultant price on the higher consuming customers in that class would be less.

Customer perception supported by the Badali report is that a fixed charge is paying something for nothing, and therefore tends to favour a high variable component. Customers would also have more incentive to reduce energy consumption where the variable component is a high percentage of the overall bill.
From a distributors perspective, if the service charge is leveraged high, the demand side management revenue risk to the LDC is not zero unless the variable component is zero. Even then, this risk is not zero unless the customer continues to be connected to the distribution system.

Recognition of some of the density cost as part of the fixed component would be crucial in establishing equity within the class. It is important that when more than one class are established for an identifiable group of customers, that there not be a such a significant difference that customers perceive the inequity as so profound as to warrant their seeking reclassification. This has long been an issue for intermittent occupancy or seasonal customers and has recently created an issue at the 50kW service boundary.

33. 2006 Rate Mitigation
- Rate mitigation may be used, as it has been historically, to reduce significant rate impacts. Should a common rate mitigation test or methodology be adopted? What test(s) or methodology for mitigating rate impacts are appropriate?

ECMI Submission

If the commodity increases by 27.91%, it will not be possible to limit impacts to 2%. Distribution is a relatively small component of the overall cost of supplying electricity. If formulaic approaches are put in place for service charges, then mitigation could well result in variable rates being reduced which would in turn produce an apparent disincentive for demand side management. Any mitigation strategy must be utility and class specific based on the specifics of all of the adjustments underpinning any rate change. Therefore “one mitigation formula fits all” does not work.

Additional Issues / Sub Issues from Informal Consultation Tuesday July 6th 2004.

1.Transmitter Capital Contributions

ECMI Submission

The utility should be able to capitalize capital contributions made to a transmitter because these are capital contributions to the transmitter not capital contributions to the distributors. These capital costs incurred by the distributor should be included in the utility's rate base. Recognizing that these costs may be subject to adjustment resulting from reduced load taken from the transmission facility, the adjustment should likewise be added to the utility's ratebase. As demand side management (DSM) happens and is effective, it is reasonable to expect that these adjustments from reduced transmission system use will occur. If the distributor has to absorb these costs, it is therefore one more disincentive for distributors to be involved in effective demand side management programs.

2.Shared Assets

ECMI Submission

To the extent that shared assets produce a lower cost for LDCs and their customers, the regulator should limit intervention which could result in increased LDC and customer costs because of the elimination of sharing. Use of LDC assets by a 3rd party, affiliate or otherwise, should result in compensation to the LDC in an amount at least sufficient to cover incremental cost.

3.Transformer Station Ownership

ECMI Submission

Distributors should not be forced to own Transmission System Assets including Transformer Stations (TS's) or transmission lines. These assets may be held by affiliates or non-affiliates of distributors. This may be a situation where Hydro One transformation rates and capital contribution requirements may provide a reasonable benchmark to measure fair cost and benefit to end use distribution customers.

4.Wholesale Meters

ECMI Submission

As wholesale meters (delivery point meters) are replaced, the full incremental cost should be recoverable by distributors to the extent that the distributors to required to make capital contributions to 3rd parties to supply the metering or incur the capital cost directly.

5. Standby Charges

ECMI Submission

In the face of DSM initiatives, standby charges, take or pay contracts and a myriad of other similar options may be an effective way of equitably distributing the cost and benefit associated with DSM.

6.Ancillary Revenue Treatment

ECMI Submission

It is apparent that the revenues recovered for 3rd party use of distribution facilities, whether an affiliate or not is a reasonable consideration for the regulator. It must be recognised that, in evaluating the approach, that the degree of commitment by the distributor may be in part a function of the potential risk of the ancillary use being eliminated. This can occur because the ancillary use goes out of business, or by 3rd party initiatives which may require that the distribution system be relocated underground. Therefore the revenue stream that flows from ancillary use activities may have a materially higher risk than the normal distribution system activities. Earnings sharing for these activities should be correspondingly weighted heavily in favour of the shareholder rather than passed onto to the customer unless the customer expects to incur significantly higher rates as a result of the falling away of ancillary activities.

7. Earnings sharing

ECMI Submission

See Ancillary Revenue Treatment above.

8. Demand Side Management (DSM) revenue erosion (impact on load forecast)

ECMI Submission

The impact on the load forecast assumes that the test year is a future year not an historical year. While it is true that revenue erosion may result as a response to DSM initiatives, the utility should be kept whole as a result of the customer response.
The following considerations are important when determining incremental costs which should be borne by customers as a result of DSM programs.

Prudency should not be the test criteria for recovery by the LDC of an expense associated with DSM. The test should be one of reasonableness.

If a utility is a high growth utility, continued growth is not necessarily a good indicator of a failure of DSM initiatives. A reduction in growth may represent a huge customer response to DSM initiatives. Further, if the growth is due to added customers, the Distribution System Code (DSC) may require the utility to make significant capital investments to supply the new customers. An effective DSM program may erode a reasonable revenue forecast for not only existing customers but for incremental or new customers resulting in revenue risk for the utility for the new customers as well as the existing customers.

There is a risk premium associated with investment in a regulated monopoly such as an LDC. That risk premium reflects, at least in part, the regulatory framework under which the utility operates. It is therefore reasonable to expect that such changes in the regulatory framework should result in commensurate adjustment in both the deemed debt cost and the return on equity. Unbalanced behaviour by the regulator may reduce investment in the electricity market in Ontario in both the distribution and generation sides.

9.SSS Administration Costs and Charges

ECMI Submission

As long as market prices are above fixed commodity rates imposed on distributors, it is reasonable that 3rd party commodity dealers, whether affiliates or not, should be required to make a significant contribution towards the carrying charges associated with such lags in price and time.

10.Defer Rate design issues to cost allocation

ECMI Submission

With the exception of the issues identified under Issue 31, most rate design issues should be deferred to the cost allocation stage.

11.Dual regulatory regime

ECMI Submission

If utilities only had to deal with only two regulatory regimes, some would consider them fortunate. Requirements of the OEB, the Power Authority, the IeMO, the Electrical Inspection Authority, Occupational Health and Safety Legislation, environmental regulation and Bill C35 are not always in conflict with each other, but seldom result in reduced cost and risk for LDC's.

12.Impact of Transmission System Code changes on Distributors

ECMI Submission

Changes to the Transmission System Code have not fully resulted in a more stable transmission system cost environment for LDCs, particularly in the face of DSM programs.

13.Bill 100 implementation

ECMI Submission

In addition to the previous comments on DSM and regulation in general, the devil is always in the details and the best intended regulation may produce unexpected and undesirable outcomes for LDCs. Implementation should be done with caution and in the recognition that the LDC industry should remain healthy as both the Power Authority try to deal with what is truly a supply side problem as opposed to a distribution problem.

14.Rate Harmonization

ECMI Submission

Rate Harmonization should be limited to minimize potential yo-yo rate impacts which might result from implementation of the cost allocation study in 2006.

15.DSM assets in rate base

ECMI Submission

Previous comments on holding the LDC harmless from the results of DSM programs should include the recognition of operating and capital costs incurred by an LDC as a result of these initiatives.

16.Distributor efficiency (dis) incentives

ECMI Submission

If mergers are to be implemented, clear demonstration of benefits to both customers and shareholders should be quantified and demonstrated as a result of merger initiatives.

17. “Desired end state” may impact 2006 EDR

ECMI Submission

The apparent linking of implementation with resolution when considering the desired end state may lead the OEB to move hastily to fix some of the issues. It is possible that the synergy of fixing some currently identified with some yet to be identified problem may result in a yo-yo impact on rates. For instance, if the immediate focus is on reducing the service charge and later considerations result in increasing the service charge as a risk management tool, then these two components may produce a rate yo-yo effect when a 3rd component like a cost allocation study is overlaid on these considerations, the yo-yo effect could be materially exacerbated.

18. Rate Year “anniversary” date

ECMI Submission

To the extent that we continue to make changes, we may reduce both regulated entity and customer confidence in the process. Movement to an April or May application date may permit all parties to have higher confidence in the December 31st fiscal year end audited statements. To the extent that this application period may increase the confidence on all parties, it may be a good initiative. Applications in early May, with a view to implementation in July may actually provide a more reasonable timetable for all parties. OEB draft guidelines should continue to be issued in December and finalised in January to allow sufficient time for a considered application in April/May.

19. Update Accounting Procedures Handbook (APH); more prescriptive accounting guidelines

ECMI Submission

As indicated earlier, clear and consistent definitions may prove an advantage to all parties.

20.Cost allocation in 2006

ECMI Submission

Cost allocation processes are more complex than currently understood by many parties. The notion that load data will fix all the problems may not be good medicine for the Ontario economy, particularly if direct distribution assets employed to serve larger use customers are not specifically allocated to those customers rather than being part of a pool.

21. 1999 Financial loss treatment

ECMI Submission

If utility’s returns are fully rebased as part of the rebasing process, then historical 1999 losses may not have to be revisited on a going forward basis.