Ontario Energy Board
26th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4
ATT: Mr. John Zych, Secretary

February 14, 2005
Dear Mr. Zych,

RP- 2004 - 0188
2006 Electricity Distribution Rates - Draft Handbook dated 10 January 2005
ECMI Coalition Argument

In accordance with the OEB ‘s Procedural Order No. 5 dated February 4 2005, the ECMI Coalition hereby submits the following arguments with respect to Alternatives shown in the Ontario Energy Board’s 2006 Electricity Distribution Rate Handbook; draft 2 dated 10 January 2005.

As requested, eight hard copies and one electronic copy of this Argument are enclosed for the Board Secretary. An Acrobat (PDF) version is also enclosed. One electronic copy has been provided to Keith Ritchie by e-mail.

Respectfully submitted for the Board’s consideration.

Roger White
President,
ECMI

Introduction

For the convenience of the parties, this Argument is submitted including sections (direct lifts) from the draft rate handbook January 10 2005, together with page references below each portion of the Handbook. The Argument regarding the Handbook follows the lift and is titled ECMI collation position. In addition, there are a few places where the ECMI position makes reference to an ECMI position on an earlier section.

ECMI and the ECMI coalition appreciates the efforts of the Board, this Panel and Board staff and all of the other participants in attempting to make this process as productive and useful to all parties as possible.

Chapter 3

Test Year and Adjustments

3.0 <u>Test Year and Adjustments</u>
If an applicant is aware of material events expected to occur in 2006, which are identifiable, quantifiable, and verifiable, it…

Alternative 1: *is obliged to disclose*

Alternative 2: *is not obliged to disclose*

…such events in the description of the application.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 16

ECMI Coalition Position
ECMI does not object to the disclosure of such material events, provided that such disclosure does not result in adverse consequences for the LDCs decision not to disclose an event item if there is any uncertainty as to the likely occurrence of the event.

3.2 Test Year Adjustments

This section details Option 1 and Option 2 test year adjustments.

Option 1: Tier 1 Adjustments

Distribution Expenses	Rate Base
OEB annual dues and other regulatory costs – adjust to 2005 actual	
Pensions – adjust to 2005 actual	
Insurance – adjust to 2005 actual	
	New transformer stations and directly-associated assets (e.g. feeders) with an in-service date of 2005
	Wholesale meters – adjust to 2005 actual
Non-routine/unusual for 2004 only and exceeding materiality threshold – 0.2% of total distribution expenses before PILs	Non-routine/unusual for 2004 only and exceeding materiality threshold – 0.2% of net fixed assets before adjustments
LV/Wheeling adjustments	
Placeholder for CDM and Smart Meters	***Placeholder for CDM and Smart Meters***
	Retirements without replacement - both rate base and P & L (depn.) - when net book value exceeds 0.2% of net fixed assets
	Alternative 1: *New transformer stations and directly-associated assets (e.g. feeders) with an in-service date of 2006 (half-rule)* ***Alternative 2:*** *exclude*

***Alternative 1*:** *Note: For new transformer stations and directly-associated assets with an in-service date of 2006, the half-rule states that only half of the rate base impact should be included in the adjustment, on the basis that 2006 is the forward-looking, rate-setting year, and such adjustments would be assumed to occur on average in mid-year, if a forward test year had been used.*

***Alternative 2*:** *no note necessary*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 18

ECMI Coalition Position

The basis for including a transformer station in the rate base is that it is a relatively large investment by the utility with a long construction period required to serve its customers. Even though ECMI does not have any clients to whom this situation would apply, it supports Alternative 1.

Further, Alternative 1 may help to mitigate the rate impact on customers in future years by recognising at least some of the investment in a transformer station in 2006 rates.

Tier 1 Adjustments: Distribution Expenses

5.) Low voltage/wheeling adjustments

The applicant should adjust the 2004 base filing for all such costs that are not included in 2004 and are not directed by the Board to be treated as either a flow-through item or placed in a deferral account.

Alternative 1: *The relevant costs would include the following, which should be identified separately:*

1. *LV recovery amounts approved by the Board in the Phase 2 regulatory asset review.*

2. *Proposed LV recovery amounts for the period January 2004 through May 2006.*

3. *Proposed Hydro One LV rates post-May 2006*

4. *Wheeling charges in cases where there are no established rates in place.*

As items 1 and 2 are of a transitory nature, they would be recovered through a rate rider. As items 3 and 4 would represent adjustments of a more permanent nature, they would be recovered through base rates, unless the Board deems this to be a transmission service in the future.

Alternative 2: *The relevant costs would include only those for which a Board decision has been made, approving their recovery. The recovery of any LV wheeling charges for which a Board decision has not been made by the application filling date is outside the scope of this proceeding.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 19 & 20

ECMI Coalition Position

The Board's Decision with Reasons, Review and Recovery of Regulatory Assets – Phase 2, dated December 9 2004, section 9.0.8 states that, " In the specific case of Low Voltage related amounts, the Board has determined that the appropriate account

for distributors to capture these costs is the Retail Transmission Account (1586, RSVA CN)".
ECMI supports Alternative 1 in recognition of the above noted decision. Any new charges should be treated consistent with this Board decision. This decision treats LV charges as a pass through and provides for a variance account to deal with these items. Whether the charges to a distributor are by Hydro One Networks Inc or by another distributor and whether the charges are retroactive or current, the recognition of these charges and a variance account treatment of these charges will not require any Tier I adjustment.

6. CDM and Smart Meters Distribution Expenses
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 20

ECMI Coalition Position
On page vi of its Report to the Minister, Smart Meter Implementation Plan dated January 26, 2005, the OEB states "The implementation plan proposes that the capital and operating costs of the smart meter system be included in a distributor's delivery rates that are charged to all customers in a particular rate class, whether or not they have a smart meter. In addition, it proposes that the costs related to old meters and other distributor assets that are made obsolete by the introduction of smart meters continue to be included in distribution charges."

Where the LDC incurs costs covered by the 2005 third tranche revenue, the existing established variance account should provide adequate treatment for the direct recovery of these costs. However, for costs and programs outside these third tranche revenues, a Tier 1 adjustment is appropriate.

While ECMI supports in principle the position on cost stated in the OEB report, clarification is required with respect to the timing of the recovery by distributors of all the costs relating to the smart meter initiative. It is ECMI's position that distributors should be able to include the non third tranche expenses for 2005 and 2006 of the smart meter initiative in their 2006 rates. Such recovery could be made by the establishment of a dedicated variance account with an appropriate and timely true-up mechanism.

Tier 1 Adjustments: Rate Base

4.) CDM and Smart Meters
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 21

ECMI Coalition Position
On page vi of its Report to the Minister, Smart Meter Implementation Plan dated January 26, 2005, the OEB states "The implementation plan proposes that the capital and operating costs of the smart meter system be included in a distributor's delivery rates that are charged to all customers in a particular rate class, whether or not they have a smart meter. In addition, it proposes that the costs related to old meters and other distributor assets that are made obsolete by the introduction of smart meters continue to be included in distribution charges."

While ECMI supports in principle the position on cost stated in the OEB report, clarification is required with respect to the timing of the recovery by distributors of the return and depreciation relating to the smart meter initiative.

It is important that the rate base recognition of the estimated 2005 capital investments associated with the smart meter program initiative be included in the rate base as part of the Tier 1 adjustments. These rate base related adjustments should include depreciation adjustments for capital investments in 2005 and 2006.

5.) <u>Non-routine/unusual adjustments</u>

These adjustments would be of the kind discussed in more detail below, applicable to 2004 only, and exceeding a materiality threshold of 0.2% of net fixed assets before adjustments.

Alternative 1: *6.) New transformer stations and directly-associated (e.g. feeders) with an in-service date of 2006 (half-rule). See above for an explanation of the half-rule.*

Alternative 2: *exclude*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 21

ECMI Coalition Position
The basis for including a transformer station in the rate base is that it is a relatively large investment by the utility with a long construction period required to serve its customers. Even though ECMI does not have any clients to whom this situation would apply, it supports Alternative 1.

Further, Alternative 1 may help to mitigate the rate impact on customers in future years by recognising at least some of the investment in a transformer station in 2006 rates.

Non-routine/unusual Tier 1 Adjustments

> Board staff has noted an inconsistency between Chapters 3 and 6. Chapter 3 prescribes removal of unusual 2004 bad debt expense as a Tier 1 adjustment, whereas Chapter 6 may allow full or partial recovery of unusual 2004 bad debt. Stakeholders are invited to address this issue in their arguments.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 22

ECMI Coalition Position

It is ECMI's view that a Tier 1adjusmtent is appropriate for an individual material bad debt write off which is "unusual" for the LDC. It is appropriate to remove this item as a 2004 expense because to fail to remove it would result it in ongoing 2006 and possibly 2007 recovery of the whole bad debt write off. The recovery of the specific material bad debt write off will be dealt with under Chapter 6 by ECMI.

Option 2: <u>Tier 2 Adjustments</u>

Alternative 1: *Tier 2 adjustments must not include any additional requests for hardship funding to address material degradation of the distribution system which may have occurred in prior periods, due to reduced revenue arising from the existence of the eligibility circumstances for the Tier 2 adjustments.*

Alternative 2: *Tier 2 adjustments may also include additional requests for hardship funding, which would be intended to address an identified material degradation of the distribution system resulting from the existence of one or both of the Tier 2 qualifying circumstances, as opposed to a normal **on-going** level of expense and investment. This is additional distribution expenses and capital expenditures related to prior years which the applicant believes is necessary to take corrective action for monies not spent in such prior years due to inadequate revenue as a result of the two circumstances outlined above. Any such amounts approved by the Board will be recovered with a rate rider to be in place for the period over which the corrective investments are to be undertaken.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 23

ECMI Coalition Position

ECMI supports Alternative 1 whereby there are no routine provisions for additional hardship allowances. While a utility may apply for any particular variance to the Handbook, the result should be an increase in the regulatory burden.

It is ECMI's view that any Tier 2 adjustments <u>not</u> identified in the Handbook would necessarily be subject to a higher standard of scrutiny as these unidentified circumstances were not tested as part of the 2006 EDR process.

Schedule 3-1: **<u>Tier 1 Adjustments</u>**

2. Other Standard Distribution Expense and Rate Base Adjustments

Please state any adjustments that have been made for the following items in the sections below, and provide a full explanation for them.

Please specify to which areas adjustments have been made (i.e. rate base, expenses).

If no adjustments have been made, please explain why.

- Low voltage/wheeling adjustments
- C & DM initiatives
- Smart Meter initiatives
- new transformer stations with a 2005 in-service date
- wholesale meters to the 2005 actuals
- retirements without replacement
- ***Alternative 1*:** *New transformer stations and directly-associated assets (e.g. feeders) with an in-service date of 2006 (half-rule)*

  ***Alternative 2*:** *exclude*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 26

ECMI Coalition Position
The basis for including a transformer station in the rate base is that it is a relatively large investment by the utility with a long construction period required to serve its customers. Even though ECMI does not have any clients to whom this situation would apply, it supports Alternative 1.

Further, Alternative 1 may help to mitigate the rate impact on customers in future years by recognising at least some of the investment in a transformer station in 2006 rates.

Schedule 3-3: <u>Tier 2 Adjustments</u>

Alternative 1:

3. *Please provide the total dollar amount,* per annum*, of the impact on distribution expenses and capital of any proposed adjustments , and an explanation as to how the breakdown between these two amounts was determined, and why the resulting amounts are appropriate.*

   Please provide, on a going-forward basis, breakdowns of the amounts proposed to be spent by USoA accounts, and information as to the specific projects to which they relate.

   Please provide this information in the following format, with the proposed timing specified on a monthly basis:

   - *capital programme adjustment requested in dollars, if any*
   - *expense impacts adjustment in dollars, if any*
   - *other impacts of proposed adjustment in dollars, if any*

Please include a detailed explanation of the nature of the projects and the estimated timing.

Alternative 2:

Alternative 1 plus the following addition:

If making additional hardship funding requests, please provide the total dollar amount that is being requested, the prior years to which it relates, a per annum *historic breakdown of the impact on distribution expenses and capital, and an explanation as to how the breakdown between these two amounts was determined and why it is appropriate.*

Please break down these amounts to specify in which of the prior years they would have been incurred, including identification of areas of under-spending of USoA accounts and information as to the specific projects to which they relate.

Please provide, on a going-forward basis, breakdowns of the amounts proposed to be spent by USoA accounts, and information as to the specific projects to which they relate.

Please provide this information in the following format, with the proposed timing specified on a monthly basis:

- *capital programme adjustment requested in dollars, if any*
- *expense impacts adjustment in dollars, if any*
- *other impacts of proposed adjustment in dollars, if any*

Please include a detailed explanation of the nature of the projects and the estimated timing.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 28 & 29

ECMI Coalition Position
ECMI supports Alternative 1 whereby there are no routine provisions for additional hardship allowances. The intent of the Handbook is not to ask the Board to revisit prior decisions. Only the two circumstances specifically identified in the rate Handbook should be accepted as expected Tier 2 adjustments. While a utility may apply for any particular variance to the Handbook, the result should be an increase in the regulatory burden.

The two identified circumstances linked to Tier 2 adjustments have merit.
In the first identified circumstance, where an LDC began the 1999 RUD process with negative returns in 1999, all including the Board reasonably expected the LDC to achieve a full market adjusted rate of return by 2003, with rebasing expected in 2004. However, the rates currently under consideration are 2006 rates, and as 2004 is the base year an adjustment is warranted.

In the second identified circumstance, Bill 210 froze rates and a few LDC's did not realize the second one third of the market adjusted revenue requirement increment.

It is ECMI's view that Tier 2 adjustments not identified in the Handbook would necessarily be subject to a higher standard of scrutiny than the two identified circumstances as these unidentified circumstances were not tested as part of the 2006 EDR process.

While LDC's may have made material adjustments in operating expenses as a result of the two identified situations, the capital components associated with those situations may be more difficult to identify. In either case, the annual adjustment to expenses combined with any requested capital adjustment should be set up so that the sum of the annual expense adjustment and the annual average capital over the period does not exceed the annual amount of any reduced revenue. (For example, an LDC did not realise its second tranche for 2002 and 2003 and 2004 and the annual amount of that second tranche was $75,000. If $50,000 of base annual operating expense recovery is claimed as part of the adjustment, then the incremental capital recovered should not exceed $25,000 times 3 years or $75,000 in capital expenditure. In addition, if a utility requests Board approval to incur and recover additional operating expenses, such operating expenses would be limited to the $50,000 times 3 years or $150,000. This additional amount should be treated on the same basis as capital for rate making purposes i.e. handled as part of a rate rider). The first component (base annual operating expenses) in the example is an effort to establish an appropriate base for operating expenses to be included on a going forward basis in the rates. Any capital recovery and/ or additional operating expenses should be treated as a rate rider and subject to a variance account adjustment if the specific capital or additional operating dollars are not spent. The base annual operating expense adjustment should not be subject to a variance account.

Chapter 4

Rate Base

4.1 Definition of Rate Base

The applicant is required to file information on its 2004 total assets, broken down into distribution and non-distribution segments.

Alternative 1: *The level of detail in this filing will be as outlined in Schedule 4-1, Appendix B, and in the 2006 EDR Model.*

Alternative 2: *The level of detail in this filing will be… [as proposed by a party supporting this alternative in argument].*

ECMI Coalition Position
ECMI wishes to reserves the right to support an aggregated proposal should an acceptable one be brought forward as part of Alternative 2.

The rate base used to determine the revenue requirement is defined as net fixed assets…

Alternative 1: *at year-end*
Alternative 2: *calculated as an average of the balances at the beginning and the end of 2004*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 30

ECMI Coalition Position
The data used in the 1999 RUD model was based on 1999 average revenue and 1999 year end rate base in order to develop 2001 rates. If a similar approach was taken in the current process, 2004 average customer count and 2004 average revenue would be used in conjunction with 2004 year end rate base to develop 2006 rates. Therefore ECM supports Alternative 1.

4.3.1 Non-IT-related

The materiality threshold for non-IT related capital investments is…

Alternative 1: *… as indicated below (same as for IT):*

Rate Base	***Materiality Threshold ($ Value)***	***Materiality Threshold (% of Fixed Assets)***
under $100 million	*75, 000*	*0.2% of net fixed assets as defined for rate base*
$100 million - $250 million	*150, 000*	*0.2% of net fixed assets as defined for rate base*
$250 million - $1 billion	*300, 000*	*0.2% of net fixed assets as defined for rate base*
greater than $1 billion	*500, 000*	*0.2% of net fixed assets as defined for rate base*

The applicant should calculate each of the materiality thresholds applicable to its particular circumstances and use the lower of the two thresholds to determine its own applicable level of materiality.

Alternative 2: *…as indicated below (no $ value threshold):*

Rate Base	***Materiality Threshold (% of Fixed Assets)***
under $100 million	*0.2% of net fixed assets as defined for rate base*
$100 million - $250 million	*0.2% of net fixed assets as defined for rate base*
$250 million - $1 billion	*0.2% of net fixed assets as defined for rate base*
greater than $1 billion	*0.2% of net fixed assets as defined for rate base*

Alternative 3: *…as indicated below (higher thresholds for under $100 million)*

Rate Base	***Materiality Threshold ($ Value)***	***Materiality Threshold (% of Net Fixed Assets)***
under $100 million	*n/a*	***To be determined**, but > 0.2% of net fixed assets as defined for rate base*
$100 million - $250 million	*150, 000*	*0.2% of net fixed assets as defined for rate base*
$250 million - $1 billion	*300, 000*	*0.2% of net fixed assets as defined for rate base*
greater than $1 billion	*500, 000*	*0.2% of net fixed assets as defined for rate base*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 32 & 33

ECMI Coalition Position
ECMI prefers Alternative 3, as it reduces the regulatory burden on both the LDC and Board staff, while retaining scrutiny for significant investments.

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

The interest rate to be used for deferral accounts is…

Alternative 1: *…the embedded cost of debt (GAAP).*

Alternative 2: *…some form of short-term debt rate.*

Alternative 3: *…deemed debt rate (5- to 10-year rate).*

The interest rate to be used for construction work in progress (CWIP) is…

Alternative 1: *…the embedded cost of debt (GAAP).*

Alternative 2: *…some form of short-term debt rate.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 34

ECMI Coalition Position

With respect to the interest rate to be used for deferral accounts, if the Board allows timely recovery (within one year) of deferral accounts then Alternative 2 is preferred. If the recovery of the deferral account is beyond one year then Alternative 3 may be appropriate. The issue here is not really the interest rate. The issue is one of timely recovery. Notwithstanding the best efforts of the Board, recovery of deferral account amounts has been delayed. This creates an apparent inequity. Deferral of deferrals is unfair to shareholders in a similar way that non clearance of variance accounts in favour of customers is not fair to customers.

With respect to the interest rate on construction work in progress (CWIP), Alternative 1 is preferred because the investment is a capital investment and whether the investment is made over 1 year or more than year, the interest rate improvement should recognise that the investment is a capital investment and the improvement should to be consistent with the capital investments as opposed to short term recovery items (less than one year), where the short term cost of money would be appropriate.

4.5 Capitalization Policy

The applicant's capitalization policy should be outlined in the description of the application…

Alternative 1: *(.) No additional wording is necessary.*

Alternative 2: *…and be filed with the application, if such a document exists.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 34

ECMI Coalition Position
ECMI supports Alternative 1

Chapter 5

Cost of Capital

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

A utility may elect a return on equity less than the maximum allowed. The utility should state the return on equity it is seeking in the description of the application.

Alternative 1: *The Board will determine the maximum allowed return on equity for 2006 using the most current data available at the time it releases its 2006 EDR decision.*

Alternative 2: *If there are changes to the Bank of Canada's 10- and 30-year Bond rates, the Board will issue a new return on equity annually. The Board will use the December forecast prior to the rate year to establish the maximum allowed return on equity.*

Given the complexity of changing the rate schedules for all distributors prior to implementing rates in May 2006, distributors will track the difference between the 2006 Handbook-issued rate, and the Board's updated maximum return on equity, in a variance account.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 39

ECMI Coalition Position

ECMI supports Alternative 1 because of the certainty provided. With the growth in the number and amounts of deferral and variance accounts, the regulatory burden on all distributors has increased. During the current time of relative financial stability, (cost of money) it is appropriate to fix the return as set out in Alternative 1.

5.2 Debt Rate

The deemed debt rate to be used for setting 2006 revenue requirements and rates is based on the forecast Long Canada Bond Rate, with a size-related adjustment, as is demonstrated in Table 5.1:

Alternative 1: *For debt held with a third party, the actual debt rate for that debt is used. For debt held with an affiliated firm (e.g. municipal share-holder, holding company), the debt rate used is the lower of the actual debt rate and the deemed debt rate. The debt rate should include all costs of issuance. The weighted average debt rate is calculated in Schedule 5-1, using the methodology applied in the following example.*

Example of weighted average debt rate calculation

The utility has a rate base of $125 million and a deemed rate of 6.61%. It has $25 million of debt with its municipal parent for 25 years at 6.75%; $20 million with the parent for 10 years at 6.45%; and $20 million of debt with an unaffiliated bank for 5 years at 6.9%.

Table 5.2 shows the calculation:

Table 5.2
Weighted Debt Rate Calculation

Organization Holding Debt	***Debt***	***Actual Debt Rate***	***Debt Rate Used (DR)***	***Reason***
Parent	*$25 million*	*6.75%*	*6.61%*	*Affiliated: use min (6.61%, actual)*
Parent	*$20 million*	*6.45%*	*6.45%*	*Affiliated: use min (6.61%, actual)*
Bank	*$20 million*	*6.90%*	*6.90%*	*Unaffiliated: use actual*
Total:	*$65 million*	***Average:***	*6.65%*	

In this example, the weighted cost of debt used for calculating the cost of capital is 6.65%.

The applicant must submit copies of the debt instrument issued to affiliates to prove the issuance date, rate, term, and expiry.

Alternative 2: *For debt held with a third party, the actual debt rate for that debt is used. For debt held with an affiliated firm (e.g. municipal shareholder, holding company), the debt rate used is the lower of the actual debt rate and the deemed debt rate <u>at the time of issuance</u>. The debt rate should include all costs of issuance. The weighted average debt rate is calculated in Schedule 5-1 using the methodology applied in the following example.*

<u>Example of weighted average debt rate calculation</u>

The utility has a rate base of $125 million and a deemed rate of 6.61%. It has $25 million of debt with its municipal parent for 25 years at 6.75%; $20 million with the parent for 10 years at 6.45%; and $20 million of debt with an unaffiliated bank for 5 years at 6.9%. Both amounts issued to the parent were negotiated at the time when the Board's deemed rate was 6.75%.

Table 5.2 shows the calculation:

Table 5.2
Weighted Debt Rate Calculation

Organization Holding Debt	***Debt***	***Actual Debt Rate***	***Debt Rate Used (DR)***	***Reason***
Parent	*$25 million*	*6.75%*	*6.75%*	*Debt issued to affiliate at time when Board's deemed rate was 6.75%: use lesser min (6.75%, actual)*
Parent	*$20 million*	*6.45%*	*6.45%*	*Affiliated: use min (6.75%, actual)*
Bank	*$20 million*	*6.90%*	*6.90%*	*Unaffiliated: use actual*
Total:	*$65 million*	***Average:***	*6.70%*	

In this example, the weighted cost of debt used for calculating the cost of capital is 6.70%.

The utility will be required to submit copies of the debt instrument issued to affiliates to prove the issuance debt, rate, term, and expiry.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 41 and 42

ECMI Coalition Position
ECMI supports Alternative 2 with the exception of debt associated with a pre-corporatization expansion. Such debt should be considered to be 3rd party debt and should be at the actual cost of that debt.

5.4 <u>Working Capital Allowance</u>

5.4.1 Introduction

Working capital allowance (WCA) represents the estimated cash flow required by the distributor to be paid in advance of recovery. It is to be included in the calculation of the rate base upon which the distributor may earn a return.

Alternative 1: *For 2006 rates, the allowance is calculated at 15% of the distribution cost of power, and other power supply expenses and controllable expenses. The general ledger accounts to be included in the working capital allowance are set out in Appendix B, Table B.2.*

Distribution Accounts within the Trial Balance Series	***Description***
4700	*Cost of power and other power supply expenses*
5000	*Distribution Expenses: Operations*
5100	*Distribution Expenses: Maintenance*
5300	*Distribution Expenses: Billing and Collecting*
5400	*Distribution Expenses: Community Relations*
5600	*Distribution Expenses: Administrative and General*

Alternative 2: *The historical cost of power should be adjusted to better reflect the actual costs expected to be incurred. An adjustment is required to reflect upward pressure on electricity prices due to legislative initiatives that cause changes in electricity generation supply mix and supply availability.*

In calculating the WCA, an adjustment to the cost of power and other power supply expenses is made, based upon a forecast of rates covering the rate period, prepared by the IMO, or other approved authority. This adjusted figure is used as the cost of power and other power supply component in the calculation.

Alternative 3: *If the forecast cost of power is not available under Alternative 2, distributors will be permitted to track the difference between the estimated and the actual cost of power in a variance account. The variance will be used to calculate the dollar value of the return due to/from the distributor's customers.*

Alternative 4: *For 2006 rates, the working capital allowance is calculated as follows:*

*[COP + 2004 Distribution Expenses with Adjustments (excluding depreciation)] * 15%*

Cost of power (COP) will be calculated in the model under COP and Contr. Expenses. COP is a function of wholesale kWh and kW volumes per customer class, multiplied by the class-specific rates for each component of the cost of power. The test year averages of kWh and kW per customer class are calculated on the Customer Demand Data page in the 2006 EDR Model, and are then adjusted for losses, where applicable, and linked to COP and Contr. Expenses.

2004 Distribution Expenses with Adjustments (excluding depreciation) will be derived from the Tab: Distribution Expenses with Adjustments, and linked to COP and Contr. Expenses.

Whichever of the four alternatives above is selected by Board, an additional adjustment could be made:

Additional Adjustment Alternative 1:

The sum of the working capital accounts is to be reduced by the dollar value of customer security deposits. The result will be multiplied by the 15% allowance.

Additional Adjustment Alternative 2:

No adjustment for customer security deposits is made in the calculation of WCA.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 43 and 44

ECMI Coalition Position
With respect to Working Capital Allowance, ECMI supports Alternative 1.

With respect to the Additional Adjustment Alternatives, ECMI supports Alternative 2. In the alternative, if the Board accepts Alternative 1, there should be an adjustment for the difference in the interest rate paid on the rate base and interest earned on security deposits.

Schedule 5-1: <u>Weighted Average Cost of Capital</u>

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
No.	**Description**	**Debt Holder**	**Is Debt Holder Affiliated? (Y/N)**	**Principal**	**Term (Years)**	**Actual Rate**	**For debt held with an affiliated firm, if Actual Rate > Size-Related Deemed DR, use DR**
1							
2							
3							
4							
Total:							**SumProduct[(5),(8)]/ Sum[(5)]**

Alternative 1: *In column (8), the comparison between the actual rate and the deemed rate should be made using the deemed debt rate shown in Table 5-1. For debt held by an unaffiliated third party, use the actual Debt Rate.*

Alternative 2: *Use the same table, with one adjustment: in column (8), use the Deemed DR from the first-generation PBR Distribution Rates Handbook (see Table 3-1 of that Handbook) for historical debt for the period 2000 to 2004, rather than the updated DR shown in Table 5-1 of the 2006 Handbook. For debt before 2000, the applicant may have to demonstrate that the debt rate was at, or below, market rates in effect at the time that the debt was issued. For debt held by an unaffiliated third party, use the actual Debt Rate.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 45

ECMI Coalition Position

ECMI supports Alternative 2. Where a promissory note with an affiliate exists, it is just that, a promissory note and the regulatory process should recognize that a distribution company, operating responsibly at the time the debt was placed, may establish promissory notes with affiliates or third parties. If the market interest rates for debt were currently higher than the interest rate on promissory notes with affiliates, it is unlikely that intervenors would be concerned.

Chapter 6

Distribution Expenses

6.0 Introduction

Level of Account Detail

Alternative 1: *Distribution expenses data are to be entered on **Tab_Trial Balance of the 2006 EDR Model**. It will be displayed and totalled on the **Distribution Expense sheet**.*

Alternative 2: *Distribution expense data are to be entered on **Tab_Grouped Trial Balance of the 2006 EDR Model**, in aggregated groupings. **(tentative)***

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 47

ECMI Coalition Position
ECMI supports a grouped trial balance reporting as described in Alternative 2. This alternative is supported because it reduces regulatory burden.

6.2.1 Insurance Expense

Recoverability of Self-insurance Costs

***Alternative 1*:** *A reasonable amount of the self-insurance reserves may be included in determining the 2006 revenue requirement. The description of the application must explain the policy followed over the period 2002 to 2004, to set the reserve.*

***Alternative 2*:** *While actual expenses for self-insured claims are allowable for calculation of the 2006 revenue requirement, any change in reserve(s) for self-insurance are not to be included in the 2006 revenue requirement.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 49

ECMI Coalition Position

No current position.

6.2.2 Bad Debt Expense

Board staff has noted an inconsistency between Chapters 3 and 6. Chapter 3 prescribes removal of unusual 2004 bad debt expense as a Tier 1 adjustment, whereas Chapter 6 may allow full or partial recovery of unusual 2004 bad debt. Stakeholders are invited to address this issue in their arguments.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 49

ECMI Coalition Position
As state under Chapter 3, Unusual 2004 bad debt expense should be treated as a Tier 1 adjustment because it affects ongoing rates and revenue. However, material bad debt expense should be treated as a Z factor and recovered through a Z factor rate rider.

6.2.4 Advertising, Political Contributions, Employee Dues, Charitable Donations, Meals/Travel and Business Entertainment, Research and Development

<u>Charitable contributions</u>

<u>Minimum Filing Requirements</u>

All applicants are to file the amounts paid in charitable donations for the years 2002, 2003, and 2004.

Alternative 1*: *Partial Recovery

50% of charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement, with the following exception:

100% of charitable contribution expenses made to programmes that provide assistance to the distributor's customers in paying their electricity consumption bills, will be included in the determination of the applicant's 2006 revenue requirement.

<u>Additional Minimum Filing Requirements</u>:

Applicants must review their 2004 expense data to segregate charitable contributions into those that are 50% recoverable (Type A), and those that are 100% recoverable (Type B). Applicants must record 50% of Type A contributions as being non-recoverable, and remove this amount.

Alternative 2*: *No Recovery

No charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement.

<u>Additional Minimum Filing Requirements</u>

Applicants must review their 2004 expense data to identify,disclose, and remove such amounts as non-recoverable.

Alternative 3*: *Full Recovery

100% of charitable contribution expenses will be included in the determination of the applicant's 2006 revenue requirement.

No amounts are to be either identified or removed as being non-recoverable.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 51 and 52

ECMI Coalition Position
ECMI supports Alternative 1. Within this alternative, ECMI supports the recovery of 50% of charitable contribution expenses as this demonstrates an allowance for good corporate citizenship. It should be recognized that just because the entity is regulated, it should not be precluded from behaving as any other legal person would when faced with the opportunity to make charitable donations. The 50% level should be sufficient to ensure that the board of directors and shareholder are at least making an equal commitment to that requested for customers. This check will afford reasonable protection to customers.

Should Alternative 1 be rejected by the Board, it is ECMI's view that the provisions of Part 2 of Alternative 1 are important and should nonetheless be allowed to stand. Part 2 allows 100% expensing for industry specific activity. This action recognises the potential customer health and safety impacts which could result from a withdrawal of electrical service. Failure to permit this alternative fails to recognise the important nature of the service. It is this important nature of the service which is a significant part of the reason fro providing regulation of distribution utilities. The OEB and government have demonstrated concern for provision of this important service and this is demonstrated by the significant investment of resources in the Regulated Price Plan and other initiatives.

Meals/travel and business entertainment expenses

The applicant must indicate in the description of the application whether or not it has a written policy, including any collective agreement(s), that sets out guidelines for management approval of meals, travel, and business entertainment expenses.

Applicants must confirm, also in the description of the application, that internal measures exist to ensure that staff meals, travel, and entertainment-related expenses included in the filing, were approved by the applicant's management, based upon a consistently-applied corporate policy.

Alternative 1*:** ***Mandatory Filing of Employer's Policy

In the description of the application, applicants will file a copy of their written policy(ies) for employee expenses in relation to meals, travel, and business entertainment.

Alternative 2: *Policies need not be filed.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 52

ECMI Coalition Position

ECMI supports Alternative2. The level of disclosure in the application should normally be sufficient. If further details are still required, an individual applicant's actual policies could be provided on request.

6.2.5 Employee Total Compensation

Guidelines for applicants with fewer than three employees

***Alternative 1*:** *Where the total number of employees for a given applicant are two, or fewer, and the average total compensation per employee is less than $100,000, no employee compensation reporting shall be required under this section.*

***Alternative 2*:** *No specific filing guidelines for applicants having two, or fewer, employees. Minimum filing requirements outlined above to be applied to all applicants.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 54

ECMI Coalition Position

ECMI supports Alternative 2 to reduce the potential for salary disclosure between two employees. If there are only two employees and the average compensation for the two employees is disclosed, then each of the two parties will know the compensation to the other party. Such disclosure may be in conflict with Federal Privacy legislation.

Additional Filing Requirements

***Alternative 1*:** *In addition to aggregated salary disclosure, total compensation for each distributor employee earning more than $100,000 per annum must be reported separately and individually.*

***Alternative 2*:** *No additional filing requirements are necessary.*
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 55

ECMI Coalition Position
ECMI supports Alternative 2 in part to reduce the potential for salary disclosure between two employees. If there are only two employees and the average compensation for the two employees is disclosed, then each of the two parties will know the compensation to the other party. Further, if there is a statutory obligation to disclose, then that statutory obligation will specify where and how and to whom such information should be disclosed, otherwise such disclosure may be in conflict with Federal Privacy legislation.

3. Incentive plans

Distributor incentive compensation plans reward employees for meeting specific performance targets. The targets can include performance which benefits ratepayers (e.g. targeted reduction in departmental OM & A expense per employee), or which benefits primarily the shareholder (e.g. percentage increase in share value).

Alternative 1: *The criteria used in any performance incentive plans must be of substantial benefit to the ratepayers in order that the amount can be included in determining 2006 revenue requirement.*

Alternative 2: *Payments for that portion of incentives that provide immediate benefits primarily to the shareholder are not eligible as a distribution expense in the approved 2006 revenue requirements, and must be considered non-recoverable.*

Alternative 2 Minimum Filing Requirements

Applicants with incentive compensation plans must file the following information in Schedule 6-1:

- *details of the incentive compensation plan(s)*
    - *include a description of the performance measures*
- *total annual dollar value of incentive compensation*
    - *breakdown the shareholder-related component and the ratepayer-related component separately*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 55

ECMI Coalition Position

ECMI supports Alternative 1.

6.2.7 Distribution Expenses Paid to Affiliates

Proposed Additional Filing Guidelines

***Alternative 1*:**

- *actual costs of the affiliate, where cost-based pricing was used for services or goods provided by the affiliate to the applicant*
- *description of if and how the absence of a market was established before using cost-based pricing*

***Alternative 2*:** *No additional filing requirements are necessary.*

Additional Wording

Alternative 1: *To help justify the reasonableness of amounts paid to affiliates for purposes of 2006 distribution rates, an applicant must provide a general explanation in Schedule 6-3 on how it followed the transfer pricing and shared service rules in the Affiliate Relationships Code.*

Where an applicant failed to follow a material requirement in the Affiliate Relationships Code transfer pricing and shared services rules, it will face additional scrutiny of these expenses in its 2006 distribution rate application. In such cases, the Board will specifically review the reasonableness of allowing full recovery of the amounts paid in the given circumstances.

Alternative 2: *Omit the above statements.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 58

ECMI Coalition Position

ECMI supports Alternative 2.

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

<u>*Affiliate Relationship Code*</u> ***(contested)***

The applicant must provide a general explanation of how they followed the transfer pricing and shared services rules in the Affiliate Relationships Code.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 65

ECMI Coalition Position
It is ECMI's position that the Section 6.3 (b) reference to the Affiliate Relationships Code should be excluded. The requirement to explain the application in the context of the Affiliate Relationships Code places undue regulatory burden on applicants.

Chapter 7
Taxes / PILs

7.1.1 General Principles Underlying the 2006 Tax Calculation

Alternative 1 below proposes a true-up for tax driven factors only.

Alternative 2 below proposes a true-up for both tax driven and operations driven factors.

Alternative 1: Partial True-up, inclusive of tax rate/tax law/assessing policy changes and reassessments

The partial true-up calculation, as shown below, attempts to balance fairly risk and rewards. A further premise of the partial true-up described below is that revenue and expenses included in the Regulatory Income before Interest and Taxes (EBIT) will not be subject to a true-up.

Each distributor shall establish a 2006 PILs/taxes variance account to capture the tax impact of the following differences:

- *any differences that result from a legislative or regulatory change to the tax rates or rules assumed in the 2006 OEB Tax Model*

- *any difference that results from a change in, or a disclosure of, a new assessing or administrative policy of the Federal or Provincial tax authorities, if the Board has declared that such new or modified assessing or administrative policy is a change of general application that should be treated as if it were a change in tax rules*

- *any difference in 2006 PILs that results from a tax re-assessment*

    - *received by the distributor after its 2006 rate application is filed, and before May 1, 2007*

    - *relating to any tax year ending prior to May 1, 2006*

    For example, if a re-assessment of a prior year results in an amount expensed in that prior year being treated as a depreciable property, the increase in 2006 depreciation may reduce 2006 PILs, and difference will be credited to the 2006 PILs/taxes variance account. Similarly, if a re-assessment of a prior year results in income reported in that prior year being deferred and becoming taxable in 2006, the difference in tax in 2006 will be debited to the 2006 PILs/taxes variance account.

Differences between actual taxes paid in 2006, and taxes recovered in rates resulting from any causes other than the three identified above, will not be credited or debited to the 2006 PILs/taxes variance account. The differences that will not be trued-up will include, but not be limited to, the following:

- *any differences resulting from actual earnings being greater or less than the forecast earnings for the rate year*
  - *shareholders will, in effect, bear the incremental tax associated with over-earnings*
  - *shareholders will have the benefit of the reduced tax cost associated with under-earnings*

- *any differences resulting from the actual mix of expenses, capital expenditures, or other components of the calculation of net income or taxable income being different from the mix assumed in the 2006 EDR Model and/or 2006 OEB Tax Model*

The above rules apply only to the 2006 PILs/taxes variance account. Any 2007 PILs/taxes variance account will be dealt with in subsequent Board decision or communication.

Alternative 2: 100% Pass-Through/True-Up

A variance account will be set up for 2006 PILs/taxes. Any variance between actual taxes and forecast taxes should be credited or debited to this account, and should be cleared to ratepayers in the following year. Such a variance account would ensure that the distributors collect from ratepayers the taxes that they actually pay.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 69 and 70

ECMI Coalition Position
ECMI supports Alternative 1, as it works to the benefit of both customers and the LDC by providing a shock absorber with respect to rate swings which could readily flow from a 100% pass through approach. In cases where the LDC is under earning, then the PILs paid by customers based on the LDC's forecast provide a cushion for increased expense and lower net income. If the LDC has a higher than forecast net income, then at least it has the money to pay the increased taxes. Further, the partial true up mechanism provides for an adjustment if the PILs rules are changed by a party other than the Board and the LDC (The Ministry of Finance).

There appears to be a perception by some parties that 100% pass through of PILs effectively turns PILs into a variance account and therefore absolves LDCs of any tax planning obligation. This perception may not be valid. LDCs may be required to exercise prudent tax planning under either a partial true up or 100% pass through alternatives. In that case, the magnitude of any pass through would only apply to the legitimate taxes after reasonable tax planning.

7.1.2 Principles Applicable to Specific Components of the Calculation

7.1.2.2 Non-recoverable and disallowed expenses

Regulatory treatment of associated reduction in actual taxes payable
in respect to non-recoverable or disallowed expenses

Alternative 1: ***Sharing Tax Savings***

*Fifty percent of the total amount of expenses non-recoverable/disallowed for regulatory purposes, but deductible for tax purposes, should be entered on line **XX** of the 2006 OEB Tax Model. This has the effect of sharing the tax savings generated by such expense equally between the ratepayers and the distributor.*

Alternative 2: ***100% of Tax Savings to Ratepayers***

*The total amount of expenses non-recoverable/disallowed for regulatory purposes, but deductible for tax purposes, should be entered on line **XX** of the 2006 OEB Tax Model. This has the effect of allocating all the tax savings generated by such expense to the ratepayers.*

Alternative 3: ***100% of Tax Savings to Distributor***

No adjustment shall be made in the 2006 OEB Tax Model for expenses non-recoverable/disallowed for regulatory purposes. This has the effect of allocating all the tax savings generated by such expense to the distributor.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 72

ECMI Coalition Position

ECMI supports Alternative 3. The shareholder/distributor has paid all the disallowed expense and not the ratepayer. It is therefore the shareholder/distributor that should gain the tax benefit. In ECMI's view, the treatment of such benefits should be determined by the tax authorities and not the regulator.

Eligible Capital Expenses (ECE):

i.) ECE with respect to any adjustment to fair market value at October 1, 2001

Alternative 1: ***Sharing Tax Savings***

To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC and in the Cumulative Eligible Capital Amounts or Disallowed Expense, the value of such adjustments for the PILs calculations, will be shared(for example 50%).

*These adjustments will be factored into Sheets **XX** and **XX** with appropriate instructions.*

Alternative 2: ***100% of Tax Savings to Ratepayer***

To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC and in the Cumulative Eligible Capital Amounts or Disallowed Expense, the value of such adjustments for the PILs calculations, will be allocated to the ratepayer.

*These adjustments will be factored into Sheets **XX** and **XX** with appropriate instructions.*

Alternative 3: ***100% of Tax Savings to Distributor***

To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC and in the Cumulative Eligible Capital Amounts or Disallowed Expense, the value of such adjustments for the PILs calculations, will be allocated to the distributor.

*These adjustments will be factored into Sheets **XX** and **XX** with appropriate instructions.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 73

ECMI Coalition Position

ECMI supports Alternative 3 giving 100% of the tax savings to the distributor because this adjustment is part of the corporatization process.

ii.) <u>ECE with respect to disallowed expense</u>

An example of this issue is purchased goodwill, and other intangible assets, disallowed for regulatory purposes.

Alternative 1: Sharing Tax Savings, Percentage Unspecified

Alternative 2: 100% of Tax Savings to Ratepayer

Alternative 3: 100% of Tax Savings to Distributor

Alternative 1, 2, or 3 will be documented in the 2006 EDR Model, after the Board's decision.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 73 and 74

ECMI Coalition Position
ECMI supports Alternative 3. If the LDC chooses to use its money to make investments from its net income, the tax implications of that investment should flow to the LDC.

Charitable donations:
The disallowed expense will be treated in one of the following ways

Alternative 1: Sharing Savings, Percentage Unspecified

Alternative 2: 100% of Tax Savings to Ratepayer

Alternative 3: 100% of Tax Savings to Distributor
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 74

ECMI Coalition Position
ECMI supports Alternative 3 for the disallowed portion of expenses. If the LDC chooses to use its money to make charitable donations from its regulatory net income, the tax implications of that donation investment should flow to the LDC.

7.1.2.4 Sharing of tax exemptions

iii.) When distribution and non-distribution functions are being undertaken in the same legal entity, as expressly contemplated under the current and future regulatory regime, then the federal LCT exemption and provincial capital tax exemptions assigned to a regulated legal entity under i.) and ii.), above, should be further pro-rated to reflect the relative asset values used in the electricity distribution activities, as opposed to other activities.

An explanation of this calculation must be included in Schedule 7-1.

Alternative to (iii): *The federal LCT tax exemption should not be pro-rated between distribution and other activities.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 76

ECMI Coalition Position

No current position.

7.1.2.7 Amortization of tangible assets and capital cost allowance (CCA)

Deduction:

The distributor must start with the undepreciated capital cost in each class at the beginning of 2005.

Alternative 1: ***Includes 2001 Fair Market Value (FMV) Bump***

The 2005 opening balance must be the same as with the closing 2004 balance for each class.

Alternative 2: ***Excludes 2001 Fair Market Value (FMV) Bump***

The 2005 opening balance must be the same as the closing 2004 balance for each class adjusted to remove all impacts of the 2001 FMV Bump.

The value of assets at October 1, 2001 for regulatory purposes is book value.

An increase in value at October 1, 2001 was required by the Ministry of Finance for tax purposes only. To the extent that the adjustment in fair market value at October 1, 2001 is included in the UCC, the value of such adjustments should be excluded from these accounts for the PILs calculation.

*These adjustments will be factored into Sheets **XX** and **XX** with appropriate instructions.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 77

ECMI Coalition Position
ECMI supports Alternative 2. In any case this position should be consistent with the decision made in 7.1.2.2.i with respect to eligible capital expenses.

7.1.2.8 Interest deduction

Alternative 1: ***Deemed (Recoverable) Interest Expense***
Interest deducted in computing the 2006 tax calculation should be the same as that allowed for recovery in the 2006 rates, as established in chapter 5 of the Handbook.

Alternative 2**:** ***Actual interest expense***

Interest deducted in computing the 2006 tax calculation must be the estimate of interest that will actually be incurred in 2006.

Alternative 3**:** ***Greater of deemed (recoverable) or actual interest expense***

The 2006 tax calculation requires that the greater of the amounts of the estimated interest expense and the deemed interest expense should be treated as a deduction for the purpose of calculating PILs/taxes.

*At its starting point, the 2006 OEB Tax Model (see line **XX**) provides automatically for the deduction of an amount of interest equal to the deemed interest rate on the prescribed debt ratio for the distributor.*

*The 2006 OEB Tax Model, however, also provides a line (see line **XX**) for any additional amount of actual interest expense, being any further interest expected to be incurred and deductible for tax purposes due to the following:*

- *a higher actual interest rate than the deemed rate*
- *a higher ratio of debt to equity than the prescribed ratio*

The distributor shall enter in that line the amount of additional interest deduction expected for tax purposes in 2006 due to either of those causes.

Alternative 4: Share of additional interest expense (unspecified percentage)

*At its starting point, the 2006 OEB Tax Model (see line **XX**) provides automatically for the deduction of an amount of interest equal to the deemed interest rate on the prescribed debt ratio for the distributor.*

*The 2006 OEB Tax Model, however, also provides a line (see line **XX**) for any additional amount of actual interest expense, being any further interest expected to be incurred and deductible for tax purposes due to the following:*

- *a higher actual interest rate than the deemed rate*
- *a higher ratio of debt to equity than the prescribed ratio*

The distributor shall enter in that line X % of the amount of additional interest deduction expected for tax purposes in 2006 due to either of those causes.
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 78 and 79

ECMI Coalition Position
ECMI supports Alternative 1. This alternative provides simplicity and a level playing field for all distributors.

7.2.2 Future Tax Information Disclosure

As part of its future filing, the distributor will be required to disclose the actual corporate PILs/taxes paid in 2006 and the amount collected in 2006 distribution rates.

If the difference between the two amounts is greater than 10%, that difference will be explained in that future filing. Distributors shall keep appropriate records of the actual, versus the recovered, PILs/taxes for 2006, and the reasons for any differences.

Alternate additional wording

Paragraphs 1 and 2 above plus the words below:

If a distributor does not have a separate tax return for the distribution portion of the business, this section will not apply.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 83

ECMI Coalition Position

ECMI supports the inclusion of the alternate with additional wording as it provides disclosure of the interest of another party which may well be of commercial value.

Schedule 7-1: <u>Sharing of Tax Exemptions</u>

2.) <u>Sharing Federal and Provincial Capital Tax Exemptions between Distribution and Non-Distribution Activities within an Applicant</u>

Contested: *It has been suggested that the LCT exemption should not be pro-rated.*

Where distribution and non-distribution activities are being undertaken within the same legal entity by an applicant, the federal Large Corporations Tax (LCT) exemption and the Ontario Capital Tax exemption should be pro-rated to reflect the relative asset values used in electricity distribution activities versus other activities.

Please provide an explanation of the pro-ration calculation.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 84

ECMI Coalition Position
No current position.

Chapter 10
Rates and Charges

10.2 Unmetered Scattered Loads

This group of accounts includes those locations that are not specifically metered, and may include such installations as bus shelters, telephone booths, CATV amplifiers, traffic signal lights, and billboard lighting.
There is considerable variability and inconsistency among distributors in the treatment of
unmetered scattered loads for rate design and billing purposes, and the levels charged to similar unmetered scattered load customers.

On an interim basis for 2006, prior to the cost allocation study and rate re-design that will take place in 2007, unmetered scattered load customers will be treated as follows:

1) A distributor that currently has unmetered scattered load charges in either of the following two manners will maintain the status quo in its 2006 rate treatment of unmetered scattered loads:

> The monthly service charge to unmetered scattered load customers having multiple unmetered connection points is on a per customer, and not a per connection point, basis, and the level of the charge is equal to, or less than, the General Service <50 kW monthly service charge per customer.

OR

> The distributor has developed and implemented a unique level of monthly service charge(s) payable by unmetered scattered load customers.

2) A distributor that currently bills its unmetered scattered load customers as small commercial or General Service <50 kW by applying the monthly service charge on a per connection point basis, shall set the level of the monthly service charge a 50% of the monthly service charge of the General Service <50 kW rate and continue to apply it on a per connection point basis.

3) From a revenue perspective, a distributor shall be kept whole as a result of any rate changes to the monthly service charge for unmetered scattered loads. Any revenue shortfall that may result from this interim measure will be recovered by means of a re-allocation of the revenue shortfall over all classes (or sub-classes or groups), in proportion to the class's (or sub-class's or group's) distribution revenue, and recovered from all the distributor's customers through both the fixed and the variable components of their respective distribution rates. The reallocation
of the revenue shortfall as a result of applying this interim measure is incorporated into the worksheet Rates 1 of the 2006 EDR Model in Appendix D.

4) The methodology used by a distributor to estimate the load profiles and energy consumptions of these types of loads is not specifically incorporated into this interim solution. In the event, however, that a reasonable estimate of the energy use for a/several delivery point(s) is required, the specific customer will have reasonable advanced notice of the proposed method, and of the estimate of the cost to the customer to establish and monitor a reasonable estimate of the energy use for a delivery point or for several delivery points.

The applicant must complete and file Schedule 10-2 **(to be written)** as part of its application.

ECMI Coalition Position

In compliance with Board's instruction on Issues Day, ECMI participated in the establishment of an interim one year compromise on the treatment of Unmetered Scattered Loads. It is ECMI's view that the issues are so profound that they could not be narrowed as the Board panel requested.

ECMI's position with respect to Unmetered Scattered Loads was submitted to the OEB on December 13th 2004, in Joint Evidence of Rogers Cable Communications Inc. and Energy Cost Management Inc. on Unmetered Scattered Load prepared by: Kevin Vagg, Network Facilities Analyst, Rogers Cable Inc.; and Paula Zarnett, Principal, Barker, Dunn & Rossi, on behalf of Rogers Cable Inc.; and by Roger White, a Principal and President of Energy Cost Management Inc.

In cross examination by Mr Shepherd, (*Extract from Transcript 18 January 2005, Ref paragraphs 254 -255)* the following response was made:-

MR. SHEPHERD: Would it be reasonable to put a cap on item 2 in the consensus? Item 2 is the one that says, Charge 50 percent of your monthly service charge for unmetered scattered load. Would it be reasonable, on a utility-by-utility basis, to put a cap on that, a cap on the impact?

MR. WHITE: It wasn't part of the consensus that was reached, so is it something that the Board may wish to consider? Absolutely.

This response should be read in parallel with the response to Tom Adams *(Extract from Transcript 18 January 2005, Ref paragraphs 281- 282)*:-

MR. ADAMS: Yes. I understand your plain reading interpretation here. Let me take as a hypothetical that there is some change in the rate environment from some external cause. For example, potentially an electricity tax that, for reasons of policy, the provincial government decides to be attached to a fixed charge. I mean, this might be something that might not have -- I mean it's a wild hypothetical, it might not have occurred in the discussions. In your view, would something outside of current discussion be captured in this point 2, or is the point 2 something that was oriented towards an analysis that started with 2004 rates and based its judgments on a review reflective of expecting current conditions, existing Board direction with regard to regulatory assets and other known quantities?

MR. WHITE: I don't think anybody within the group is a clairvoyant. You know, if rules change fundamentally and 100 percent of all costs were allocated on the service charge, there might be those who would make submissions that the interim proposal needed to be revisited. I can't, you know -- there isn't a perfect answer for your question. If the rules change then all of us rely on the Board to use its usual common sense and judgment in terms of determining whether the interim solution needs to be adjusted, because fundamental principles have been changed that underpin any rate design issues that are before the Board.

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

A distributor's adjustment factor to reflect system losses, including unaccounted-for energy, should reflect the current situation, to the extent practical.

The applicant must file Schedule 10-5 to update its current loss adjustment factors, including class-specific factors, that were established as part of its original rate unbundling process. The 2006 loss factor adjustments shall be based on a three-year average (2002, 2003, and 2004).

If the applicant determines that specific information warrants a departure from that average (e.g. gain or loss of large customers), it must include in Schedule 10-5 a description of the change from the proposed methodology, with a detailed explanation and justification for the variance.

Alternative 1: *Variances in distribution system losses costs, including both variances in loss volumes (kWh) and variances in the electricity commodity cost per kWh will be either credited or debited to the **XXX** Variance Account in accordance with the current practice. All distribution system losses cost variances, therefore, will be pass-through items.*

Alternative 2: *An amount, equal to the distributor's actual 2006 average annual electricity commodity cost per kWh times the loss volumes (kWh) originally projected and included in rates, will be calculated after the end of 2006. To the extent that this amount is greater or less than the dollar amount of distribution system losses costs used for 2006 rates, the difference will be either credited or debited to the **XXX** Variance Account. Only distribution system losses cost variances caused by electricity commodity cost variances, therefore, will be a pass-through item.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 103 and 104

Losses

The ECMI Argument with respect to losses is divided into the following sections:-

- Loss treatment in the gas industry
- The nature of electrical distribution system losses
- Degree of control
- Risks and benefits of a fixed loss factor
- Shift of risk
- Alternative Incentives to a fixed loss factor
- ECMI Coalition Position

Loss treatment in the gas industry

In cross examination by Mr White (Extract from Transcript February 3 2005, Ref paragraphs176-178) the following response was made:-

MR. WHITE: Thank you. Are you familiar that, within the gas industry in Ontario, regulated by this Board, that losses are a pass-through?

MR. CHERNICK: That's my understanding. 177

If one considers symmetry with the gas industry appropriate, electricity distributors should have losses treated through a variance account.

The nature of electrical distribution system losses

In written evidence, R White stated that electrical distribution system losses are both fixed and variable, and the variable change on an hour by hour basis and are function of the square of the current used to deliver the energy.

In oral testimony (extract from Transcript January 28 2005, paragraphs 733-734) R White identified some of the factors affecting electrical losses:-

MR. STEVENS: And I note that on this page, page 3 and the following page of your evidence, you describe the considerations that affect the amount of system losses. Could you please describe for the Panel the primary factors or circumstances that you believe affect or impact upon the magnitude of system losses.

MR. WHITE: One of the key factors is the distance that the load is from the transmission point or the delivery point to the utility. Theft of power and energy is a relatively small component, but it is also a component that contributes to losses and unaccounted for energy, which is the more full and proper name for the category. Normal meter error also contributes to the amount of unaccounted-for energy that may be lost in the system, and by that I mean the meters used on retail customers have a tolerance up to 734

2 percent in the current marketplace. So that level of error is considered to be acceptable within Industry Canada standards.

735

It's interesting to note that as existing meters get older, the older dual-type meters would tend to run more slowly and record less energy than the -- than is actually consumed at the end-use customer's premise because of the friction component associated with the meter.

736

Also, as I described earlier, the amount of energy used to energize the system, and by that we mean when voltage is supplied to a system, when you have an alternating current supply. There is a micro current that flows through the system to energize the lines and energize the transformers and make power available at the end-use customer's premises, whether or not the energy is used, any energy is used.

737

Also, the voltage of the system will materially affect the losses. Losses are a function of the current amperage and time, the energy losses, and as such, the higher the voltage, the smaller the current required to deliver the same amount of power and energy.

738

Density of the service area will also affect the amount of energy that's required. And again, because of the I2R function in terms of the use of energy in, if you will, transporting the power and energy from the delivery point to the end-use customer is a significantly variable component in the losses.

When people look at electric utility losses, they see a loss factor which implies a consistent level of losses, but, in fact, losses vary on an hour-by-hour basis. In fact, when the system demand is highest, say, in an air-conditioning period when the wires are hotter, for a utility that might have average losses of 5 percent, their losses during that time period may be 10 percent, or 12 percent, or even higher, depending upon the degree of load on the particular components of the distribution system.

740

In a similar way, if you had a small customer located at the end of a long line extension that used very little energy, the fixed component of the losses for that customer might be 100 percent or 200 percent of the energy the customer used, if the customer was truly using a small amount energy.

Degree of control

It was also stated that there are losses internal to the utility’s distribution system and losses external to the utility’s distribution system. Both Mr Goulding and Mr Chernick stated that to the extent that a utility does not have direct ownership, operation and control over portions of the distribution system which supply the utility and/or its end use customers, it should not be held responsible or incented with respect to losses on such facilities.

The following response (extract from transcript February 3 2005, paragraphs 71-72) was made under cross examination:-

MR. WHITE: Okay. If the loss factors that the utilities use are based on the delivery from the transmission system to the transformation connection as a virtual meter point - or whatever you want to characterize it as - and, to the extent that local distribution systems are not in direct control of the assets which may contribute to losses, should those losses - which they have no direct control over - should they be included in the fixed-loss component?

MR. GOULDING: The point of incentives, obviously, is to deal with areas that a utility does have under its direct control. And, clearly, if there are issues with embedded systems that cause external losses that are internal to the system that is receiving the incentive, that -- the system should not face a penalty for things outside of its control. 72

The following response (extract from transcript February 3 2005, paragraphs 173-174) was also made under cross examination:-

MR. WHITE: To the extent that end-use customer losses -- I'm sorry, what are built into the losses that end-use customers pay for are not related directly to the control ownership of the utility, should losses associated with those equipment, such as transformer stations or lines outside the utility that may be owned by somebody else, should they be part of any loss-cap mechanism or should it just be the assets over which the utility has some specific and direct control? 173

MR. CHERNICK: I think that's -- that question is related to the specific arrangements between the parties. And if, in fact, an LDC has no influence over the subtransmission losses that it's being charged, because it's being charged 3.5 percent by tariff, there's no point in trying to give the LDC an incentive for controlling those losses. 174

Risks and benefits of a fixed loss factor

In his oral testimony (Extract from Transcript February 2 2005, ref paragraphs 80-83), Mr Goulding agreed that the magnitude of potential loss reduction in Ontario is relatively small:-

MR. WHITE: If, in Ontario, for the losses which utilities had direct control over -- if that loss factor were, typically, under, say, 5 percent, would you think that there is -- based on your broader experience, that there's a huge amount to be harvested there? Not saying that we should ignore any opportunity to reduce energy consumption, but is that consistent with the numbers that you would expect to produce significant opportunity?

MR. GOULDING: Well, I think you're right to point out that, in many of the systems where a loss factor incentive is deployed, you're talking about substantially larger losses. And, in some cases, those are a combination of technical and so-called "commercial" losses. So -- you know, we're talking about systems in which you can easily see losses of 20 percent, so the magnitude of the gains that we're talking about are much higher.

In North America, the problem of losses is much lower and, you know, I certainly don't disagree with you that the magnitude here in Ontario is -- would likely be relatively small.

In his written evidence Mr White provided appendices which illustrated the potential risk due to the loss or gain of a major customer for both a high loss and low loss situation and the loss or gain of a merchant generator with different annual hours of delivery. The extract from written evidence is included below.

> “Appendices 1 and 2 illustrate the potentially major impacts that the loss or gain of a major customer or the addition or loss of a merchant generator could reasonably be expected to have on an LDC. Appendix 1 deals with the loss of a major customer but the numbers would be symmetrical for the gain of a major customer. Appendix 2 deals with the gain of a merchant generator, but the impact would be symmetrical for the loss of a merchant generator.
>
> Appendix 1 deals with the loss of a major customer for a live utility and examines the universal loss factor versus the likely range of actual losses under Scenarios 1 & 2. There is a comparison of what the loss factor and the actual losses for a relatively low loss customer (Scenario1) and a relatively high loss customer (Scenario 2). For each of these scenarios, three alternate average commodity price implications are included; price 1 at 5.0 cents/KW.h; price 2 at 5.5 cents/KW.h; price 3 at 6.0 cents/KW.h. The last line of each data block shows the adverse impact of the loss of a major customer as a percentage of the shareholder’s deemed component of full MARR. Under Scenario 1 considerations it is a relatively low loss customer. The adverse impacts range from 14.8% to 17.8% of full MARR.
> Under the scenario 2 considerations for the loss of a high loss customer, the benefit to the utility ranges from 5.6% to 6.7% of full MARR.
>
> Appendix 2 deals with the gain of a small merchant generator and the potential impact on the average losses that a utility would experience as a result of a change in losses due to the merchant generator’s connection on the low voltage side of the utility’s distribution station. Low voltage (44kV) system line losses would be reduced and distribution station losses would be eliminated so an impact of minus 3% associated with the energy delivered by the merchant generator is plausible. Under price 1, a price of 5.0 cents / kW.h is used, under price 2, a price of 5.5 cents / kW.h is used and under price 3, a price of 6.0 cents / kW.h is used. For each of these price alternatives, available energy from the generator is considered using 100% reliability, 80% reliability and 50% for the merchant generator. Under the 100% reliability, the range in benefit is from 21.9% to 26.3% of the shareholder’s deemed full MARR. Similarly the range for 85% reliability is 17.5% to 21.0%. At 50% reliability the range is from 11.0% to 13.1%. For the loss of a merchant generator, these positive impacts would be adverse and symmetrical.”

Both Mr Goulding and Mr Chernick agreed that a Z factor type treatment could be required for this type of situation:-

Extract from Transcript February 2 2005, Ref Paragraphs 56-59.

MR. WHITE: Would you suggest that if this Board were to consider putting a fixed loss factor regime in place, that they also provide for those kinds of eventualities or possibilities?

MR. GOULDING: Well, I think that as we move towards the use of incentives throughout the rate-making process, it becomes increasingly important to have what, in private business, we would refer to as force majeure provisions, ways of dealing with things that are truly beyond a utility's control. 57

In many rate-making processes we have the constant of the Z factor. Obviously, in different jurisdictions that's used differently. But, effectively, I would say that if you're going to go with a deemed-loss factor, and there are factors -- large external events that cause your current performance to diverge from historical performance, then there should be a mechanism for that to be recognized. 58

Extract from Transcript February 3 2005, Ref paragraphs 169-173.

MR. WHITE: Thank you. Just so you're not disappointed, I'd like to talk for a few minutes about losses. In the Energy Cost Management evidence, there was an indication that the loss of a relatively low-loss customer might have an impact on the utility's return, the equity component of the return of 14 to 18 percent of that return. Would you consider that significant?

MR. CHERNICK: A 14 percent reduction in return, yes. I think that's the sort of thing that management would certainly pay attention to, that would cause them great concern. 170

MR. WHITE: Would -- in Mr. Goulding's evidence, he suggested that that might be the grounds for a Z-factor type adjustment or some type of adjustment on that basis. Would you concur with that? 171

MR. CHERNICK: Yes. I guess the way I would put it is that if you do have a formula that puts a lot of risk on utility for loss factors, then there should be some opportunity for the utility to come in and say, Well, yes, but things changed in a way that we can explain. And the burden should be on the utility to show a clear connection, but there should be some kind of way out. 172

Shift of Risk

In the Board decision on Issues Day, the Board decided that the rate of return on the rate base would involve a mechanistic update only. As such, the ECMI coalition argues that it is inappropriate to impose a fixed loss factor risk on LDCs in the absence of revisiting the risk premium included in the rate of return.

Alternative Incentives to a fixed loss factor

Mr. White in written evidence stated that Alternatives 3 and 4 , set out below were both acceptable options to provide LDCs with loss reduction incentives :-

Alternative 3

If the Board wishes to incent loss reduction, a Shared Savings Mechanism may be best of all options but might be difficult to separate the loss reduction investment from normal capital expenditure. This alternative is acceptable but may be difficult to implement.

Alternative 4

Accelerated recognition of loss reduction investments in the rate base is a reasonable alternative.

Assuming that the separation of incremental loss reduction investment can be separated from normal investment, this alternative would be the simplest incentive alternative to introduce. It may produce a lower long term risk to the customers of over crediting the loss reduction investment as any rebasing of the assets would capture what is already identified as a real investment in the distribution system, whether motivated by loss reduction or other considerations.

In oral cross examination by Mr Poch, Mr White provided a specific mechanism for dealing with accelerated incremental rate base (return) recognition through the use of the variance account associated with losses. This is included below.

(Extract from Transcript January 28 2005 paragraphs 1109 to 1113)

MR. POCH: All right. Now, I'm going to paraphrase what Mr. Chernick has to offer as a suggestion, and then I'm going to ask for your comment. And to summarize, Mr. Chernick, who discusses this at page 13 of his evidence, he implies that the problem has been the uncertainty and long delay that the LDCs have faced in being able to add loss reduction investments into rate base. He suggests that regular opportunities to rebase would address the issue for capital investments. He adds that it may be appropriate for it to allow utilities to earn a return in a deferral account if rebasing is delayed, and he suggests that for large, non-capital expenditures, it may be appropriate to allow the utility to defer these expenses in a variance account or to receive the benefit of the loss reduction while awaiting a rate change.

1110

So I want to ask you how close Mr. Chernick's prescription comes to the alternative you've indicated you would find acceptable, being accelerated recognition?

1111

MR. WHITE: It certainly is closer than alternative 2 that I've examined, and I guess there may be ways to fine-tune some of the specific suggestions he makes that would make the system work even easier. The notion of potentially allowing the, say, the short-run incremental return to flow into the variance account associated with losses might be a way to deal with it so that it is a clear account that is going to be cleared when the --

when that particular account is cleared. And the only comment I would put on that is I'm sure, like many of my clients, I shudder at variance and deferral accounts as we go through some of the processes we have to go through, but there might be an easy way to make that work. And moving that incremental return to the variance account would terminate, of course, once any rebasing happened.

MR. POCH: Yes. 1112

MR. WHITE: So it would be a way of accelerating that process. 1113

ECMI Coalition Position

ECMI supports Alternative 1 in the Rate Handbook and rejects Alternative 2 because a utility should not win or lose (net income) by accident . ECMI has proposed two alternate ways of incenting loss reduction, both of which add less risk to both customers and distributors from unplanned loss reductions or increases. It is the ECMI position that Alternatives 3 and 4 (as modified in oral testimony to Mr Poch and shown above) in Mr White’s evidence be considered for inclusion in the C& DM Chapter as loss reduction incentives.

10.6 Distributed Generation

Distributed generation (DG) is defined as, a merchant generator located within a distributor and connected directly to the distribution system to provide electricity to the distributor. This does not include a transmission-connected DG.

Alternative 1: *status quo: do not change the current process*

Alternative 2: *The following methodology will be made available to, and will be used by, all distributors as an interim measure for the 2006 rates process. The issue will be examined more completely as part of the 2007 rate process.*

Methodology

1.) The distributor will continue to pay its transmission charges on a net basis in accordance with the Board's wholesale transmission rate schedule.

The distributor will continue to charge the current retail transmission service charges to its customers as if all the electricity requirements were being served from the transmission system.

With respect to generation developed after the current rates were set, since the rates have not been reduced to take into account that new generation, the distributor is effectively billing the load customers on a gross basis, with the differences being accumulated in the respective RSVA accounts.

2.) The distributor will provide a transmission credit to the DG reflecting the lower transmission charges being billed to the distributor achieved by locating the generation within the distributor.

3.) The transmission charge reductions will be shown as a credit to the DG. The credit will be funded by the transmission charge reductions accumulated in the RSVA accounts.

Alternative 2 (a):

4.) The level of the credit will be determined as a result of the DG's contribution that results in the actual reduction in the distributor's delivery point billing demands used for the calculation of the distributor's transmission charges, with the full amount being credited to the DG. A credit would not be payable to the DG if the DG output does not reduce network, line connection, or transformation charges paid by the distributor.

Alternative 2 (b):

4.) *The level of the credit will be determined as a result of the DG's contribution that results in the actual reduction in the distributor's delivery point billing demands used for the calculation of the distributor's transmission charges, with 50% of the amount being credited to the DG. A credit would not be payable to the DG if the DG output does not reduce network, line connection, or transformation charges paid by the distributor.*

5.) *The credit will be available to any DG that fulfils the Distribution System Code requirements for a generator to connect to the distributor's distribution system, subject to the physical and practical limitations within a distributor's distribution system.*

6.) *End-use load customers that have load displacement generation will have the option of being billed retail transmission charges as if the generation was not on-site, and in return receive the credits outlined above for the distributed generation.*

7.) *The distributor…*

Alternative 2 (c): *will*

Alternative 2 (d): *may*

… apply for a monthly administration charge to recover the incremental cost of monitoring, billing, and administration related to the DG credit. Such a charge will require a separate cost-justified submission as part of the distributor's Specific Service Charges (see Chapter 11).

Each distributor must file Schedule 10-6 to identify its acceptance of the proposed methodology. If a distributor proposes an alternative to this methodology, it must complete and file the last part of Schedule 10-6 outlining the methodology it proposes, including a detailed explanation and justification for the variance from the proposed methodology.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Pages 104 and 105

ECMI Coalition Position

ECMI supports Alternatives 2, 2a, 2c. Other customers of the LDC will get the benefit of loss reduction which will be real loss reductions for most if not all LDCs. From a transmission rate perspective, these end use customers of the LDC will be no worse off than if there was no Distributed Generation within the utility boundaries.

This is not a transmitter rate question but it is a question of what rates a distributor should charge its customers. If the Board is interested in promoting distributed generation, Alternatives 2,2a and 2c honour the no harm to end use customers of the LDC concept while providing a measured incentive to distributed generation. The benefit to the Distributed Generator is dependent on its ability to operate in such a way that it provides benefit to the distributor through reduced losses and utilises the current price signals that the transmitter imposes on those distributors to determine the benefit that flows to the distributed generator.

Chapter 13
Mitigation

12.0 Introduction

This chapter remains tentative and incomplete. The finalization of this chapter will await the Board's decision.

The 2006 EDR Model will reconcile the total revenue requirement and the total revenue to be collected.

13.1 Impact Analyses

The establishment of electricity distribution rates based upon an updated revenue requirement (as a result of revisions to rate base and return criteria), together with modifications to cost allocations and other rate design issues, will result in bill impacts to customers within a class, sub-class, or group.

Impact analyses must be competed by the distributor and filed as part of its application.

Calculation of these bill impacts will be an integral component of the 2006 EDR Model. An applicant must enter its 2005 rates into the 2006 EDR Model.

In conducting an impact analysis for each class, sub-class, or group of customers, both of the following comparisons will be provided by the 2006 EDR Model.:.

- The comparison between bills based on the proposed and the existing rates (including Board-approved rate riders or adders), based upon a customer's "total" bill (including a commodity component and other rates), in order to get an order of magnitude.

  It is understood that the commodity price and other rates are not known at this time. The bill comparison, therefore, should assume a constant commodity price and other rates, despite potential changes as a result of the Regulated Price Plan, other rate changes, and Smart Meter fees, as applicable.

- The comparison between bills based upon the proposed and the existing rates (including Board-approved rate riders or adders), based upon the "distribution" component of a customer's bill (i.e. excluding the commodity component and other rates).

  This comparison removes any uncertainty about the levels of the "non-distribution" rates, and only focuses on those aspects of a customer's bill that are directly approved by the Board.

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 141

ECMI Coalition Position
Any deferment of revenue by a distributor as part of a mitigation strategy should be exclusively at the initiative of the distributor. The electric distribution bill has been restructured, resulting in a blur of delivery charges. The notion of analysing distribution rates when it is in fact the entire bill that the customer pays may not produce an expected response from the customer. The LDC should not be required to mitigate commodity price adjustments or required pricing adjustments.

If the proposed comprise on the Unmetered Scattered Loads (Chapter 10.2) is accepted, no mitigation should be required because of the compliance with the Chapter 10.2 compromise**.**

13.2 Mitigation Methodologies

If an applicant undertakes any mitigation measures that are to be included in its 2006 rates (e.g., changes to the fixed/variable split), it must provide a detailed description and justification of the measures taken.

An applicant must file the following information if its rates/rates for certain classes exceed ***X***% ***(contested)***.

A distributor will undertake the following mitigation measures: ***to be completed after the Board's decision***.

Rate Harmonization (Amalgamated or Acquired Service Areas)

Alternative 1: *Distributors who have a merged, acquired, or amalgamated service area, and who have not yet fully harmonized the rates between or among the affected distribution utilities or service areas, may file a rate harmonization plan. The plan must include a detailed explanation, justification, implementation plan, and an impact analysis.*

Alternative 2: *Rate harmonization applications generally should await the cost allocation study to be completed for the 2007 rate year.*

Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 141

ECMI Coalition Position

ECMI supports Alternative 1. Rate Harmonization may be a multi year process and to defer rate harmonisation pending a cost allocation study may deprive customers with benefits associated with harmonisation. Mergers or acquisitions which occurred a number of years ago may no longer cost based underpinning that existed at the time of the merger or acquisition. To perpetuate these rates when it is the utilities intention to harmonize them may well mitigate against the best interests of customers.

Chapter 14

Comparators and Cohorts

14.1 <u>Methodology</u>

In order to facilitate review and assessment of the 2006 rate applications, Board staff will use comparators and cohorts to screen the applications.

The methodology to determine the comparators is as follows:

To be determined.

The methodology to determine the cohorts is as follows:

To be determined.

14.2 <u>Filing Requirements</u>

The comparators and cohorts will be determined on the basis of data filed by distributors.

Applicants must file, no later than *month, day,* 2005, the following information on Schedule 14-1:

To be determined.

The analysis performed on this information will be…

Alternative 1: *…provided to Board staff.*

Alternative 2: *…provided to Board staff and to all distributors.*

Alternative 3: *…posted on the Board's Web site.*

Alternative 4: *(other?)*
Ref: EDR Handbook Draft 2 dated 10 January 2005, Page 142

The ECMI argument on comparators and cohorts is structured around six sections

- Screening tool
- Base Capital Levels
- Number of cohorts
- Potential exclusion of HONI and or Toronto
- Learning process
- ECMI coalition position

Screening tool
The Board decided in the Issues Day part of the process that comparators and cohorts will be used as a screening tool for Board staff only.

Base Capital Levels
The use of base capital levels, will be at the very least a difficult process for the Ontario situation. Historical data is not available for partial acquisitions and even for some of the total acquisitions or mergers. Some historical information beyond the statue of limitations may not be available.

The following response (*Extract from Transcript January 28 2005, paragraphs114-119)* was made in direct examination. This evidence indicates some of the difficulties associated with the establishment of capital structures:-

MR. ROGERS: All right. Thank you.

114

Now, can we come to this -- just this issue about capital cost benchmarking that I discussed yesterday with Mr. Camfield. Can you give us your view about that.

115

DR. LOWRY: Well, this is a controversial issue, and I sympathize with the desire to benchmark capital but it needs -- I think the Board really needs to go into this one with their eyes open as to what they're getting into. It's a very complicated business that involves, what I might call, alien concepts of how capital costs should be measured.

116

When I was talking a moment ago about how I had the wrong sign in that formula, well, that's the very formula that the Ontario Energy Board is heading towards using in assessing the capital costs of these companies. It's something that virtually no one in the province has ever had any dealings with, and to be honest with you, it's a big part of the reason why PBR isn't more widely used in the United States. That when you show -- Mr. Camfield mentioned yesterday that this is the approach to capital costing that's used in productivity measurement, and it is, and that's one of the big reasons that productivity measurement is used almost nowhere in the United States in energy regulation.

117

Another problem with it is that you're going to have to -- to do it accurately, it's generally considered that you have to go back many years in developing the proper estimate of the size of the capital stock.

As I understand Mr. Camfield's proposal, he's not even proposing to go back -- well, he has not yet specifically proposed to go back many years at all. And what you're basically talk being is getting all the planned addition data back to some benchmark year, and in our work for power distribution utilities in the United States, we go back to 1964. And I have a very hard time imagining, with all the mergers that have been done, and the fact that so many of these LDCs might not have kept the right kinds of records over years, being previously co-ops or municipal organizations or something like that, it would be very hard to do.

118

Then to add further to the problem is the fact that even after you've done all that work, you're still not there yet, because there's still going to be an issue of the pattern of investment over the years that got you to where you are today. A slow growing utility, for example, will typically have a lower capital cost because the investments that they made occurred so many different years ago. And even after you've made this adjustment that Mr. Camfield is proposing, you still have that problem. And I'm sorry to say I have just found this to my, I don't want to say dismay, but I've had increasing concern about this over the years. Because I have done capital cost benchmarking for over a decade, and the more I see of it, the more I realize that you really need to go back to the drawing boards and upgrade this technology before I'm going to be happy doing it again.

119

So we're talking about very experimental adjustments that, really, there's almost no precedent for. The literature that exists on power distribution benchmarking, for example, says very, very little about capital costs, because in most parts of the world there is no good capital cost data available. So you're really in an area of the frontier of the methodology to do a responsible job on that.

The following response (*Extract from Transcript January 28 2005, paragraphs 458-459)* was also made in cross examination,

MR. WHITE: Okay. If I were to also suggest that utilities in Ontario, most of them that are public utilities, were using straight-line depreciation, and part of their accounting processes, they were using, typically, 25 years, with 4 percent per year, and if, at the end of that 25-year period, if both the original cost of the asset and the accumulated depreciation associated with that asset were removed, notwithstanding the fact that it was still in service, would that in any way influence the ability to use accumulated depreciation as a percent of total plant?

DR. LOWRY: Well, a 25-year -- I mean, what stuck out to me when you said that is that 25 years is awfully short. So if you don't have a depreciation of rates that are in line with the actual service life, yes, it's going to degrade the value of that measure.

This demonstrates that trying to use the relationship between original cost and accumulated depreciation may be difficult if not impossible because of the accounting practices in Ontario

Number of cohorts

The selection of cohorts has not been made on an analytical basis:-

MR. WHITE: Not quite, but we can move on regardless.

If -- in an earlier discussion we had, you indicated that the number of cohorts was not scientifically selected as part of this process, whether it be 4 or 10. 1001

MR. CAMFIELD: Yes. 1002
(Extract from Transcript January 27, paragraphs 1001 -1002)

The implications of selecting a number of number of cohorts can produce migration of LDCs from outlier status to non outlier statues or vive versa.
The following response (e*xtract from Transcript January 27 2005, paragraphs 1005 - 1006) was* made in cross examination

MR. WHITE: I'm going to put to you the question that, if you decide, initially, to go with 4 cohorts, for example, and if you were to look at 3 cohorts and 5 cohorts as possible comparison groups that you're going to define, isn't it possible that an outlier in a 4-cohort sample would end up not being an outlier on a 5-cohort sample, or a 3-cohort sample?

MR. CAMFIELD: That's correct. 1006

The apparent arbitrariness in the selection of the number of cohorts with the directly linked possible outcomes which can cause an LDC to move either from an outlier to a non outlier or from a non outlier to an outlier ("accidental" outlier), depending on the number of cohorts selected. This apparent accident of number of cohort selections could have a materially adverse impact on both the regulatory burden imposed on an "accidental" outlier and on public perception of any information released regarding the identification of "accidental" outliers.

Potential exclusion of HONI and/or Toronto

It was suggested by Dr Lowry that some of the largest utilities did not belong as part of any cohort solely because of their size. The following response (extract from Transcript 28 January 2005, Ref paragraph 472) was made in cross examination:--

DR. LOWRY: As I say, I could see different treatments for the two or three largest companies. And I would think that the Board, who actually doesn't have extensive experience in power distribution economics anyway, wouldn't just want to sit down and a stem-to-stern, traditional rate case for a few of the companies.

The notion that a future test has eliminated the value of comparators and cohorts is inappropriate from ECMI's perspective. Comparators and cohorts either have value or they don't. The notion that Toronto and or HONI do not belong in any comparator and cohort analysis is, from Dr Lowry's evidence, underpinned by the premise that the primary dominant and only apparent item worth considering is customer count.

Given the analysis and the cost drivers that have been prepared by Mr Canfield, it is a fundamental that there are other considerations apart from customer count. The customer count as the only driver or dominant driver for all situations does not recognise the Ontario marketplace.

In the following transcript extract (Transcript, 27 January 2005, Ref paragraph 302. Mr Canfield recognised the need for these additional considerations:-

MR. CAMFIELD: Well, the C&C mechanism will identify, at least as I have designed it, the framework will identify relationships, as the study discusses, between cost drivers and costs. These cost drivers include the levels of services provided. It includes, in some cases, substitution resources, such as capital, within operating expense analyses. It includes business context variables.

Also, in the transcript for 27 January 2005, Ref paragraph 307 :-

MR. CAMFIELD: Well, the determination of, say -- let's just set this up as, kind of, a context for the question. Let's imagine that we have an LDC that has an unusual business context that is implicit within the data that it files. The determination of a uniqueness, of idiosyncratic attributes that make it unusual would be not determined in the filing of the data, but would be determined in the analyses based upon the data.

As Mr Camfield states, it is the analysis of the data that will drive the decision on the treatment of an LDC. It cannot be claimed that a scientific analysis has been completed if the rigour is taken out of the process. One cannot exclude a utility before the analysis is done.

In later cross examination, (Extract from Transcript, 27 January 2005, Ref paragraphs 959-962), Mr White asked Mr Camfield why Hydro One was specifically excluded:-

MR. WHITE: Okay. Now, so, in a lot of ways, they are somewhat like LDCs, because they serve urban areas and they have an urban rate for it, and they serve high-density areas, which are small towns and small communities that meet their high-density criteria, and they supply what some people call a lot of moose pasture where they have a lot of "rural" customers which have a lower density. And I think the number is somewhere in the order of 14 customers per kilometre of line, so less than that to fall into the rural category.

I'm wondering, just on the face of it, why that would be excluded? Because sure it's got some density issues, but density is something you're looking at when you're gathering information, and I'm wondering why it would be excluded when other utilities that have similar density criteria, and some of them have as high as 38 percent "normal" density, or the lowest of Hydro One's density criteria, why they would be included when Hydro One is excluded? And frankly I'm looking for some help so that I can explain it to my clients.

MR. CAMFIELD: This comes to me as a complete surprise, and I would have to explore the institutional framework of the LDCs that you speak of, Mr. White, before I could answer your question. But it's certainly something that I wish to explore, and I'll try to do that.

This response confirms that HONI was excluded by Mr Camfield without sufficient analysis. This is inconsistent with the previously recognised importance of rigour in the analysis. Therefore, reviewing Dr Lowry and Mr Camfield's evidence, Mr Camfield has no basis for excluding HONI and Toronto, while Dr Lowry apparently relies exclusively on size as the exclusive or even dominant criteria which is inconsistent with the apparent description of Mr Canfield's proposed analysis and modelling.

Learning process

The following response (*Extract from Transcript January 27 2005, paragraphs 570 - 571)* was made in cross examination:-

MR. ROGERS: So we're -- I don't mean this critically, but we're all kind of learning here together, then -- you, too.

MR. CAMFIELD: No doubt.

Surely in the learning process, it would not be inappropriate to include HONI and Toronto until we know what really are the cost drivers proven by data and what the cost drivers are, not just an assumed number of customers. Comparators and cohorts may be a useful tool, but in the interim, all LDCs, including Hydro One and Toronto, should be kept in data pool so we learn as much as we can from the learning process.

ECMI Coalition Position

ECMI supports Alternative 4 which the ECMI coalition suggests should be structured as follows. The data should be provided to Board staff, all distributors and only to intervenors on a confidential basis. This is essential during this learning stage of C&C in an effort to build knowledge in all parties before any distribution to the broader public is considered. Erroneous or even possibly erroneous identification of an LDC as an outlier could result in irreparable damage to both the credibility of the LDC and potentially it financial integrity and viability.

Conservation & Demand Management (C& DM)

The ECMI coalition supports C& DM initiatives. The recognition of the Ontario governments' expectation for energy use reduction is a significant factor in our support for these initiatives. In an effort to make SSMs, LRAMs and TRC tests useful for Ontario LDC's, it is crucial that as many of the variables as is reasonable be specified by the Board as part of a pre approval process. Use of a forecast commodity cost without a true up would provide a higher level of inducement to LDC participation. A menu of pre quantified energy reduction benefits resulting from particular appliance conversions would be helpful from both a utility predictability perspective and a customer understanding perspective. If a screw-in fluorescent light bulb is worth 50 cents on the Detroit River it should similarly be worth 50 cents on the shores of James Bay. Broad based public participation in programs will enhance the effectiveness of the programs. True ups based on variables beyond the control of the distributor, may make LDCs reluctant to participate in some initiatives. It is apparent that Board staff, the Green Energy Coalition, Energy Probe and Pollution Probe along with customer groups should have a material influence in prescreening the preapproved inputs to used in evaluating program benefits. Their creative yet divergent views may provide better options for the Ontario marketplace. Further early identification of free rider inputs and other key assumptions to be used in program success evaluation is an important aspect of moving the markers forward. The greater the time and money spent on the audit process may divert necessary utility dollars from delivering programs to dealing with the regulatory and auditing burden. These costs would have to be part of the cost recovery associated with C&DM initiatives.

In conclusion, the efforts of the Board for 2005 have started the learning process for many distributors. This learning process may provide a solid foundation for the C& DM industry for and beyond 2006.