EDA SUBMISSION TO ONTARIO ENERGY BOARD ON 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK

RP-2004-0188

February 14, 2005

Introduction

The EDA submission is divided into chapters of the draft Electricity Distribution Rates Handbook. Issues are addressed in the order they appear in the draft Handbook.

Chapter 3

Test Year and Adjustments

Section 3.0 Test Year and Adjustments

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.

EDA supports Alternative 2.

The EDA supports the position that LDCs are not obliged to disclose what material events they expect in 2006. Alternative 1, where applicants are required to disclose material events expected to occur in 2006, may involve a judgment call by LDCs on whether an event would be material before it occurs and a judgement call after by the regulator on whether the LDC should have known and expected the event and its materiality. Alternative 1 is more appropriate for a forward test year application, where more efforts are put towards projecting future costs.

Section 3.2 Test Year Adjustments

Option 1: Tier 1 Adjustments

***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*

EDA supports Alternative 1

Where a significant material event such as a new transformer station which is planned and expected to be in-service in 2006, it should be included in the rate base as it would be if a forward test year had been used (i.e. half-rule). This approach would be fair to distributors expecting in-service dates of 2006 and allow these distributors to avoid the significant expense of filing a forward test year application. The EDA understands that other stakeholders may argue that when using a historical test year basis, distributors should not be able to selectively choose which items to include from a future year. Nevertheless, the EDA believes new transformer stations require special consideration, as they are large capital investments that if not included in the rate base immediately could create financial problems for the distributor. The treatment of large capital investments, when rebasing is not occurring, is a significant industry issue. The solution to this issue should not be a requirement to make an application on a forward test year basis every time a new transformer station is expected. As a result, recognition should be given now that transformer stations will be given a different treatment and allowed into rate base without having to file a forward test year application.

Tier 1 Adjustments: Distribution Expenses

5.) Low voltage/wheeling adjustments

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.

The EDA supports Alternative 1.

Alternative 1 recognizes the expected costs from pending decisions on LV recovery and proposed LV rates. The only rationale for not including these LV costs would be if there were any uncertainties as to whether LV costs will be passed onto embedded distributors by 2006. Alternative 2 could be unfair to distributors if there was not a timely approval for the recovery of LV costs passed onto distributors.

Non-routine/unusual Tier 1 Adjustments

Some examples would include the following:

- bad debt write-off associated with bankruptcy or equivalent of a major customer

  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.

EDA position

The EDA disagrees with Board staff on their view regarding inconsistency between Chapter 3 and 6. Chapter 3 addresses the removal of very large one-time bad debt expenses, such as bankruptcies of a distributor’s largest industrial customer. Chapter 6 requires a reporting of the expected level of bad debt, which is representative of historical norms. Item 3 in that section requests additional support for a level above the norm.

Option 2: Tier 2 Adjustments

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.

The EDA supports Alternative 2.

Alternative 2 allows LDCs to address material degradation of their distribution system caused by inadequate funding due to starting with negative returns in 1999 or not receiving the second third of market-adjusted revenue requirement. This approach would be the only way to allow these distributors disadvantaged by outside circumstances to catch up with other distributors, so that going forward they would be a on a level playing field with respect to ongoing expenditures to maintaining service and reliability.

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].*

All applicants must file rate base information for the years 2002, 2003, and 2004.

The EDA supports Alternative 1

The level of detail outlined in Schedule 4-1 is adequate for filing purposes. The EDA agrees with Board staff that this level of detail will reduce the volume of information to be reviewed and will be more useful in identifying trends and unusual cost experiences (Tr. Vol. 11 para. 927). When trends are identified, Board staff and intervenors will have the opportunity to ask for more details through interrogatories.

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*

The EDA supports Alternative 1.

Using the year-end net fixed assets to determine the rate base is more appropriate than the average balance because the 2004 year-end values represent the most up-to-date audited rate base values at the time of filing. Given that the rate base is used to determine the revenue requirement for 2006, the rate base should be based on the most current values available. In addition, the asset will be in service for more than a year at the initiation of the 2006 rates. This approach also simplifies the filing.

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*

The applicant should determine 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.

Where applicable, 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.

EDA supports Alternative 2.

The EDA supports Alternative 2 and the use of a consistent materiality threshold for all distributors. The other alternatives will result in filing a level of detail that will be of little added benefit.

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).*

EDA supports Alternative 1

Board staff noted that the past practice for interest rates for deferral accounts has been to let the Board select the interest rate when the deferral account is established (Tr. Vol.

11 para. 908). The evidence by all witnesses on this issue indicates that the character of the deferral account must be considered when establishing an appropriate interest rate. It may be impractical to establish an interest rate approach for all potential deferral accounts. The EDA believes this issue should not be addressed in the Rate Handbook and that it would be more practical for a decision on interests rates for a particular deferral account be made when the account is established.

Mr. M.G Matwichuk, partner in Stephen Johnson Chartered Accountants, appearing on behalf of Vulnerable Energy Consumers Coalition (VECC) notes in his evidence that that the practice across the country for interest rates for deferral accounts is inconsistent and ranges up to the weighted average cost of capital (Ex. B1 page 8, Tr. Vol. 3 para. 72). Mr. Matwichuk noted that a recent OEB procedural order established a deferral account for costs associated with conservation and demand management incurred prior to March 1, 2005 at a rate approximately 175 basis points above prime (Ex. B1 p. 16 line 11).

Mr. Matwichuk provided a table on size-related debt formula (Ex. B1 p. 22) based on consideration of a sample of 15 financial statements of Ontario distributors (Ex. B1 p. 15 line 26). Mr Matwichuk acknowledges that this table was based on a snapshot in time based on the data he had available (Tr. Vol. 3, para. 442).

The approach suggested by Mr. Matwichuk is without regulatory precedence in Canada and is far lower than any previously approved by this Board.

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.*

EDA supports neither Alternative

The embedded cost of capital provides a better matching to CWIP asset's.

Mr. Matwichuk agreed that the appropriate rate is the embedded cost of capital, not the embedded cost of debt as set out in Alternative 1. This would include both the equity and debt financing.

The VECC witness, Mr. Matwichuk, in his evidence (Exhibit B1 page 17-18) indicates that the CWIP rate should be Allowance for Funds Used During Construction which uses a weighted average cost of capital for a utility whose capital structure includes an equity component. Mr. Matwichuk's review of other regulatory practices in other jurisdictions indicated that where there is equity financing of rate base, the CWIP included carrying charges based on the rate of return on rate base (Exhibit B1 page 6).

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.*

EDA support Alternative 1

With respect to Capitalization Policy the EDA supports Alternative 1 where the capitalization policy would not need to be filed. The description of the applicant's capitalization policy will provide the relevant information necessary to review the application.

Chapter 5

Cost of Capital

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

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.

The EDA supports Alternative 2

Alternative 2 allows for the establishment of rates reflecting the most current market conditions, thereby minimizing market risks. Alternative 2 is consistent with Dr. Cannon's recommendations. Dr. Cannon, in his 1998 discussion paper on the determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario, recommended that the allowed equity return be updated annually.

5.2 <u>Debt Rate</u>

<u>Weighted average debt rate</u>

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.

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.

EDA supports Alternative 2.

For debt held with an affiliated firm, Alternative 2 uses the lower of the actual debt and the deemed debt at the time of issuance. This approach recognizes that long-term arrangements made in the past were based on the deemed debt rate at the time. Distributors should not be penalized for prudently issued debt in a previous period.

5.4 <u>Working Capital Allowance</u>

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.

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.

The EDA supports Alternative 2 with additional adjustment Alternative 2

The working capital allowance should continue to be calculated at 15% of the distribution cost of power and other power supply expenses and controllable expenses but with an adjustment to the historical cost of power to reflect expected upward changes to electricity prices.

There should be no adjustment to the working capital allowance for customer security deposits because distributors pay interest on security deposits and therefore deposits are only a source of very short-term financing and distributors are required to refund deposits under the provisions of the Distribution System Code.

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							
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.

The EDA supports Alternative 2.

Alternative 2 is consistent with above argument to use the deemed debt rate at time of issuance.

Chapter 6

Distribution Expenses

6.0 Introduction

General requirement for three years of supporting data

All applicants must file distribution expenses for the years 2002, 2003, and 2004.

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)***

EDA supports Alternative 2

A Grouped Trial Balance would be sufficient for filing and the purposes of screening and identifying trends. This will avoid the problem with inconsistent allocations with the grouped accounts.

The EDA agrees with Board staff that this level of detail will reduce the volume of information to be reviewed and will be more useful in identifying trends and unusual cost experiences (Tr. Vol. 11 para 927). When trends are identified, Board staff and intervenors will have the opportunity to ask for more details through interrogatories.

6.2 Detailed Reporting for Specific Distribution Expenses

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.

The EDA supports Alternative 2.

For utilities that use self-insurance, to simplify the approval process the EDA recommends the use of 2004 actual claims experience.

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

Charitable contributions

Minimum Filing Requirements

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.

Additional Minimum Filing Requirements:

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.

Additional Minimum Filing Requirements

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.

EDA supports Alternative 3

The EDA supports full recovery of charitable contributions as they generally all benefit the communities the distributor serves.

Note that programmes that provide assistance to customers in paying their electricity bills serves dual purposes as it lends a helping hand to those persons in need and it reduces the bad debts of the distributor. The reduction of the bad debts results in lower distribution rates that otherwise would have been written off and would have been included in 6.2.2 Bad Debts.

Meals/travel and business entertainment expenses

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.*

EDA supports Alternative 2

Utilities should not be required to file their written policies for employee expenses. This would be seen as micromanaging and unnecessary given that the description of the policy should provide adequate information to ensure distributors maintain controls for these expenses.

6.2.5 Employee Total Compensation

2. Minimum Filing Requirements

Where there are three, or fewer, full-time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs.

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.

The EDA supports Alternative 1.

Alternative 1 will ensure employee confidentiality for those with salaries below $100,000. Provincial public employees with salaries below $100,000 have not been required to declare their salaries. As noted by Board staff, disclosure of individual salaries may be in conflict with municipal or provincial privacy legislation (Tr. Vol. 11 para. 939)

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.

EDA supports Alternative 2.

Alternative 2 will ensure employee confidentiality. As noted above, disclosure of individual salaries may be in conflict with municipal or provincial privacy legislation. Distribution employees are working for business corporations and are not public employees. Neither the regulator nor the public needs to know individual salaries as overall compensation levels are adequate for regulatory scrutiny.

3. Incentive plans

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*

EDA supports Alternative 1.

The EDA believes performance incentive plans of distributors substantially benefit ratepayers. Alternative 1 avoids the need to involve the regulator in reviewing incentive plans and making judgements on the split between shareholder and ratepayer benefits.

6.2.7 Distribution Expenses Paid to Affiliates

Affiliate transactions

At the time of writing, the Board has recently released its amendments to the Affiliate Relationships Code for Gas Utilities and Interpretive Guidance to the Code.

Participants may wish to review these documents in making their arguments on this section of the 2006 Handbook.

Minimum Filing Requirements

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.*

EDA supports Alternative 2.

Alternative 2 requires less administration. The implementation of additional filing requirements as indicated in Alternative 1 would create a significant administrative burden on distributors and the regulator. This additional information should only be necessary when there was an investigation by the Board's audit or compliance function. As noted by Board staff, it can be assumed that distributors are in compliance with the Affiliate Relationship Code and inquiries into compliance with the code should be left to the Board's compliance office (Tr. Vol. 11 para. 944)

In addition disclosure of the actual costs of the affiliate may result in releasing confidential information, which could place the affiliate at a competitive disadvantage.

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.*

EDA supports Alternative 2

As above, Alternative 2 requires less administration. These details on affiliate transactions are only required during a review by the Board's audit or compliance functions.

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.

EDA supports Alternative 1.

As provided in the evidence entitled Review of Proposed Methodologies for the Treatment of Taxes for Rate Setting Purposes (Exhibit B 2) given by J. Krukowski, Tax Partner – Power and Utilities Practice, and J. Erling, Director - Regulatory Economics, of KPMG, Alternative 1 which provides a true-up for only tax rule changes is the most appropriate option as it results in less administrative burden, greater rate stability, and lower risk to distributors than Alternative 1 (Tr. Vol. 1 paras. 156-157). Under this option ratepayers are not subject to true-ups that magnify earning volatility and in the long run benefit from lower costs due to lower cost of capital from lower utility risk (Tr. Vol. 1 para. 159). Utility risk is reduced through reduction in the volatility of earnings since "the effect of corporate taxes under the no-true-up method is to act as a cushion against changes in revenue and expenses from forecast" (Tr. Vol. 1 para 161)

Mr. Erling noted that no-true would encourage utilities to explore tax avoidance strategies but they do so at their own cost and risk, and utilities that do not pursue these strategies are no worse off. (Tr. Vol. 1 para 163)

As proposed by Jennifer Lea in her questions to Mr. Krukowski, the EDA agrees that Alternative 1 should be amended by replacing “Any difference in 2006 PILS, the results from a tax reassessment” with “Tax reassessments related to the ongoing operation of the distribution system” (Tr. Vol. 1 para 269)

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

Although an expense may be non-recoverable or disallowed for regulatory purposes, the distributor may still be able to claim it in its actual tax returns filed, thus affecting the amount of tax payable in respect of the 2006 rate year.

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.

EDA supports Alternative 3

As indicated in the evidence entitled” The Disposition of Tax Savings on Disallowed Expenses” (Exhibit B 9) by K. C. McShane, Senior Vice President and senior consultant with Foster Associates, Alternative 3 is the appropriate approach where tax savings arising from disallowed operating expenses flow to the utility, based on the regulatory principles of “benefits follow costs”, the “stand-alone utility” and the “no harm” to ratepayers, and the government objective for a “level playing field”.

As summarized on page 2 of her evidence, and in her testimony (Tr. Vol. 5 paras. 79-86) Ms. McShane indicates that the “benefits follow costs” principle requires the shareholder who incurs the costs be entitled to the related tax savings. The “stand-alone” principle requires that only costs and risks pertaining to the activities of the regulated utility be reflected in the revenue requirement and this includes income tax allowance. A “level playing field” was one of the stated objectives of the Government when Payments in Lieu of Taxes (PILs) were imposed on electric utilities (Tr. Vol. 5. para. 293-4).

Ms. McShane notes that the “stand alone” principle is an essential principle of regulation that has been virtually adopted by every other regulator in the country (Tr. Vol. 5 para. 354) and that the Board adopted this principle in 1981 when Consumers Gas was acquired by Hiram Walker (Tr. Vol. 5 paras.546-7) and that the principle was developed and applied 30 years ago (Tr. Vol. 5 para. 600).

Mr. Erling of KPMG concurred with Ms McShane’s reasons for supporting Alternative 3 (Tr. Vol. 1 paras. 300-303)

Eligible Capital Expenses (ECE):

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.*

EDA supports Alternative 3.

Consistent with the rationale on the treatment for tax savings from disallowed expenses, the EDA supports Alternative 3.

Ms. McShane notes that the tax savings from the fair market value adjustment required by the Ministry of Finance for tax purposes should flow to shareholders on the basis of the “stand alone” principle, the “level playing field” objective and the “no harm” principle. The “no harm” principle states that when neither the shareholder nor the ratepayer incurs any costs, but the shareholder gains a benefit, there is no harm to ratepayers***.***

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.

EDA supports Alternative 3

Consistent with the rationale on the treatment for tax savings from disallowed expenses, the EDA supports Alternative 3

Consistent with above arguments by Ms. McShane, Alternative 3 is the appropriate approach based on the regulatory principles of “benefits follow costs”, the “stand-alone utility” and the “no harm” to ratepayers, and the government objective for a “level playing field”.

<u>Charitable donations</u>:

The amount of charitable donations calculated under accounting rules is an add-back on line ***X***. The amount to be deducted on line x is the lesser of:

- allowed regulatory amount as determined in Chapter 6
- the amount of charitable deductions allowed for tax purposes

If the allowable tax deductions should exceed the amount above, that excess will be included as a disallowed expense on line ***XX***. The estimate is to be calculated under the Federal T2 method, and back-up calculation is to be retained.

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

EDA supports Alternative 3

Alternative 3 is consistent with the "benefits follow costs" principle noted by Ms McShane. This is a shareholder expense, and ratepayers should not receive a benefit.

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

Maximum CCA must be claimed when computing taxes payable for purposes of the 2006 OEB Tax Model.

The following steps must be taken for the purpose of determining amortization of tangible assets (depreciation) and CCA in 2006:

Add-back:

The distributor should add back the distribution-only amortization amount, including Tier 1 adjustments in the 2006 EDR Model.

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.*

EDA supports Alternative 2.

Consistent with the rationale on the treatment for tax savings from eligible capital expense with respect the adjustment to fair market value at October 1, 2001, the EDA supports Alternative 2.

Mr. Krukowski of KPMG notes that the tax savings from the fair market value adjustment should go to the distributor because of the level playing field issue (Tr. Vol.1 para. 287) and the "benefit follow cost" principle (Tr. Vol. 1 para. 407)

Ms McShane of Foster Associates agrees that there is a level playing field issue and the "benefit follow costs" principle applies as well as the "stand-alone", and "no-harm" principles (Tr. Vol. 5 paras. 93-100).

<u>Undepreciated Capital Cost Calculation</u>

<u>7.1.2.8 Interest deduction</u>

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.

EDA supports Alternative 1

Alternative 1 should be used since interest deducted in computing the 2006 tax calculation should be the same as that allowed for recovery in 2006 rates, as established in Chapter 5 of the Handbook.

Chapter 10

Rates and Charges

10.5 <u>Update of Loss Adjustment Factor Reflecting System Losses Including Unaccounted-for Energy</u>

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.*

The EDA supports Alternative 1 and 3

Alternative 1 ensues losses are treated as a pass through. As noted in Roger White's evidence entitled" Conservation and Demand Management – Loss Factor Incentives" (Exhibit C 4), distributors could be placed at significant financial risk if Alternative 2 was chosen. Alternative 2 was an attempt to provide distributors with an incentive to reduce losses by allowing them to retain any loss reduction over a given period. The problem with this approach is that it puts loss reduction initiatives on an unequal footing with other CDM initiatives.

Evidence filed by Roger White (Exhibit C 4provided additional alternatives 3 and 4.

Alternative 3
The LDC receives an incentive based on the Total Resource Cost Test and receives an incentive above normal return of the LDC. This is effectively a Shared Savings Mechanism.

Alternative 4
No specific incentive to the utility, save and except the assurance that any investment made flows into the rate base and the utility is allowed a return on it which would be timely and independent of any generic rebasing.

Alternative 3 could be added to Alternative 1. Losses would still be a pass through but distributors would assess loss reduction programs on the same basis as other CDM programs. Treating loss reduction programs on the same basis as other CDM program would ensure LDCs do not prefer customer CDM programs over loss reduction programs. Loss reduction programs often require significant capital expenditures but some initiatives require ongoing operating costs and little capital (Tr. Vol. 8 para. 202). Some witnesses suggested that distributors already have an incentive to continue to reduce losses and would do so without any additional incentive (Tr. Vol. 8 para. 923). This is clearly a misunderstanding of the present situation distributors face. With limited resources distributors will seek to invest in activities that provide the best returns and rewards. An unlevelled treatment in favour of customer CDM programs over loss reduction programs will ensure distributors will no longer pursue loss reductions initiatives, just as new opportunities for loss reduction are appearing. As noted by Mr. Goulding, the Board staff's expert witness on CDM, it would be inappropriate to distinguish between investments behind or in front of the meter when investigating the range of economic CDM activities (Tr. Vol. 8 para. 201).

The treatment of capital and expenses for CDM programs is still to be determined. If all CDM costs are capitalized, then the treatment of loss reduction initiatives may be consistent. If is decided that most CDM costs are to be expensed, it would be preferred that loss reduction capital investments continue to be capitalized, and given a discounted shared savings incentive which in total with the added return on equity would approximate the present value of the shared savings from CDM programs with the equivalent Total Resource Cost (TRC) value.

Alternative 4 would provide little incentive to encourage loss reduction incentives. Getting a return on capital invested is not an extra incentive but rather just compensating distributors for use of their funds (Tr. Vol. 8 para. 806). It does not provide an incentive level with CDM programs. In addition, this approach does not provide rewards for any increases in operating expenses.

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.

EDA takes no position

The crediting of DG for transmission savings created will require additional administrative efforts for LDC and could cause significant changes to billing systems. LDCs should be allowed to recover these additional costs if there are changes to the status quo.

Chapter 13

Mitigation

13.2 Mitigation Methodologies

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.

EDA supports Alternative 1

Given it is not mandatory to file a rate harmonization plan, this allows the utility to decide whether it should begin to harmonize or wait for the cost allocation in 2007. Individual distributors should be allowed to begin to harmonize the rates from amalgamated areas where there are clearly significant rate disparities between areas. Where differences between areas are smaller, distributors would wait for the cost allocation in 2007 to avoid the risk that rates would be changed in the wrong direction in 2006.

Other Rate Mitigation Arguments

Evidence filed by W. Harper and J. Poon (Exhibit B 6) on behalf of the Vulnerable Energy Consumers Coalition (VECC) recommended a rate mitigation approach that required additional filing requirements for LDCs with proposed overall average distribution rate increases of over 8%. The filing requirements would require a variance analysis and identification of key cost drivers. For increases over 16%, a justification for the key cost drivers would also be required. For increases over 25% a plan was required on how the increase will be mitigated. These thresholds for increases were based in part on whether the expected overall total impact on bills would result in customers experiencing “rate shock”. Mr. Harper clarified that LDCs should not be required to either forego or mitigate cost increases because of the impacts associated with other parts of the market (Tr. Vol. 4 para. 99). Mr. Harper explained that the specific thresholds he proposed were based on his judgments (Tr. Vol. 4 paras. 665-6).

Evidence filed by Derek HasBrouck and James Heidell of PA Consulting Group (exhibit B 8) on behalf of Hydro One recommended that the OEB should not use a formulaic threshold. They noted that the need for rate mitigation should not be based on the costs associated with implementing electricity restructuring including the adjustment to market based rates which were policy implementation decisions and not related to the distributors ability to control costs. If a threshold test is used, it should be a single threshold for determining who would qualify for a simplified review and not for determining whether rate mitigation is required (Tr. Vol. 4. para. 863).

Mr. Hasbrouck cautioned against overly prescriptive and mechanistic application screening, noting a case-by case basis would be better. (Tr. Vol. 4 para 1217)

The EDA supports the recommendations of Mr. Hasbrouck and Mr. Heidell.

Chapter 14

Comparators and Cohorts

14.1 Methodology

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.

(Note Undertaking No. E.6.3 provides Mr. Camfield's proposed addition)

14.2 Filing Requirements

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?)*

EDA supports Alternative 1.

The EDA is concerned that this initial Comparators and Cohorts analysis will be based on data that may still be compromised and inconsistent to a degree and if released to the public may result in misleading conclusions that can do harm to the distributor. If data is shared beyond Board staff it will be difficult to control its distribution and would likely be provided to consultants and other parties and eventually made public.

Mr. Camfield, the Board staff's expert witness on comparators and cohorts noted in his testimony that the mechanism suggested does not provide an appropriate basis to assess or gauge the overall performance of a distributor (Tr. Vol. 6 para. 203). To develop comparators and cohorts that the OEB and distributors would be reasonably comfortable with could take years. Therefore, until the mechanism is more fully developed, it would be inappropriate to release this data to the public.

It should also be noted that the comparators and cohorts mechanism suggested by Mr. Camfield is a long way from comprehensive benchmarking. As Mr. Camfield noted in the hearings there is a considerable amount of work to bring together and integrate very diverse measures of performance into a benchmarking mechanism.

Appendix B: <u>Rate Base Accounts</u>

This appendix may be unnecessary, depending upon the level of detail in the 2006 EDR Model, in Appendix D.

<u>Definition of Rate Base</u>

Rate base is defined as, the net fixed assets…

Alternative 1: *at year-end*

Alternative 2: *an average of the balances at the beginning of 2004 and the end of 2004*

…plus a working capital allowance. The working capital allowance to be included in the rate base is 15% of the sum of the cost of power and controllable expenses. Controllable expenses are defined as, the sum of operations and maintenance, billing and collection, and administration expenses.

<u>Calculation of Net Fixed Assets, Distribution Assets</u>

The total of the…

Alternative 1: *year-end*

Alternative 2: *average of the balances at the beginning of 2004 and the end of 2004*

…amounts in the accounts below (as applicable) will be used to calculate the net fixed assets for subsequent fillings.

The EDA supports Alternative 1.

The EDA supports using year-end data for both definition of rate base and calculation of net fixed assets, to be consistent with previous positions.

Conservation and Demand Management

The draft Rate Handbook does not contain a chapter on CDM. Evidence filed by Board staff is summarized below.

Evidence filed by AJ Goulding of London Economics International, entitled "Overview of CDM practices in North America and Potential Alternatives for Ontario" (Exhibit C 1), retained by OEB staff, indicated that LDCs should be provided with revenue recovery mechanisms and incentives to implement cost-effective CDM programs. The witness provided four hypothetical models described as follows:

1) "pay as you go" Lost Revenue Adjustment Mechanism (LRAM) - LRAM recovered prospectively through an upfront surcharge with an annual true up, operating and capital cost of CDM programs expensed, and a bonus incentive based on actual savings;
2) "pay over time" LRAM – LRAM recovered through a deferral account, operating and capital costs of CDM programs capitalized in the rate base, a shared savings mechanism based on calculation of expected net benefits;
3) "high powered shared savings" – no LRAM, but SSM based on high portion (75%) of savings collected through a prospective upfront surcharge with an annual true up, and operating and capital cost of CDM programs expensed;
4) "flat rate pricing and customer bill savings" – no LRAM but rates based on fixed connection charge basis (therefore no change in distribution revenue from changes in sales), a shared savings mechanism recovered retrospectively through a surcharge based on 50% of achieved reduction from previous year, and 50% operating and capital costs of CDM programs expensed and 50% capitalized in the rate base.

It was noted that Model 1 was least disruptive to utility cash flow, required a modest administrative burden, but caused higher short-term rate increases, and smaller incentives to LDCs. Model 2 would lower the initial rate impact, has a fair degree of administrative burden, and higher incentives for LDCs. Model 3 provides moderate bill impact but is administratively complex and difficult for small LDCs, and the incentives are much higher due to no LRAM. Model 4 requires change in rate structures, which may defer its implementation, but it does align LDCs and customer incentives. It was noted that aspects of each model could be interchanged with other models.

Other evidence filed by Jack Gibbons of Pollution Probe "A Lost Revenue Adjustment Mechanism and Shared Savings Mechanism for Ontario's Electric Utilities" (Exhibit C 3), Paul Chernick of Resource Insight for Green Energy Coalition entitled "Cost Recovery for Conservation and Demand Management for Ontario Electric-Distribution Utilities" (Exhibit C 2), and Mr. Heeney of IndEco Strategic Consulting and Peter Love of the Canadian Energy Efficiency Alliance entitled "Towards standardization and simplicity for aggressive conservation and demand management in 2006" (Exhibit C6) all generally support the" pay as you go" model. Each of these experts was generally supportive of each other's recommendations.

All experts agreed that distributors required financial incentives to encourage efficient and effective behaviour regarding CDM.

Mr. Goulding said incentives will focus management attention (Tr. Vol. 8 para. 669); encourage effectiveness (Tr. Vol.8 para. 681) and the highest level of efficiency (Tr. Vol. 9 para. 766). He noted that distributor management would be in breach of fiduciary duty if they aggressively pursued programs, which provided no financial return for their shareholders (Tr. Vol. 8 paras. 318-20).

Mr. Chernick said incentives are needed to change the institutional mind-set of distributors and have them pursue the benefits made available for carrying out CDM initiatives (Tr. Vol. 9 para. 860).

Mr. Gibbons said incentives are needed to create a financial self-interest to pursue CDM (Tr. Vol. 10 para 1024). He believes conservation should be pursued on a business basis and therefore should be made profitable for distributors (Tr. Vol. 11 para. 542)

All the experts agreed on the need to establish standard programs and pre-approve input parameters.

Mr. Chernick said standardization of program designs and input assumptions would eliminate need for each distributor to develop the individually (Tr. Vol. 9 para. 870). Mr. Chernick notes as many inputs as possible should be fixed going into the process (Tr. Vol. 10 para. 298). He recommended a process to involve stakeholders to develop cost/benefit analysis for standard programs (Tr. Vol. 10 paras. 674-5).

Mr. Gibbons noted that distributors have clearly indicated that they need regulatory certainty and need to have pre-approval of input assumptions so that they can be assured their programs will be acceptable to the Board (Tr. Vol. 10 para. 1065). Mr. Gibbons agrees with the distributors. The inputs to approve would be those that are key to the calculation of the shared savings (Tr. Vol. 11 para. 807).

Mr. Heeney agreed that inputs such as measure life, free-ridership rate, and savings per measure should be pre-approved (Tr. Vol. 11 paras. 159-60)

Mr. Goulding also supported pre-approval of some inputs (Tr. Vol. 9 para. 105)

EDA position on CDM

The EDA agrees with the basic recommendations of the CDM experts. All the expert witnesses on CDM were unanimous in their position that for distributors to effectively deliver CDM programs they would need:

- recovery of all prudently incurred costs associated with CDM activity;
- recovery of lost revenues resulting from reduced electricity consumption; and

- incentives tied to the savings created by CDM programs, in order to encourage distributors to make their best efforts in creating and delivering CDM programs.

The EDA supports a CDM regulatory framework that allows distributors to recover their CDM costs, allows pre-approval of inputs, protects revenues through a lost revenue adjustment mechanism and provides incentives through a shared savings mechanism. The EDA supports the development of a conservation handbook that would provide assistance on filing requirements and program screening calculations.

Recovery of program expenditures and the costs of the administrative effort is a fundamental requirement for distributors to carry out CDM activities. The preferred cost recovery mechanism would be to collect the revenue during the same period as costs are being incurred.

Recovery of lost revenues due to CDM activities is required to protect the financial viability of the distributor and remove a primary disincentive for willing participation in CDM initiatives. The experts agreed that a prospective LRAM would reduce the size of the variance accounts and would not negatively impact the distributor's cash flow. Although it may be difficult for distributors to forecast CDM program results at this early stage in the ramping up of CDM activities, distributors should be given the option of using a prospective LRAM. A distributor should be allowed to propose a load forecast for rate setting that incorporates energy and peak demand reductions associated with planned CDM activity and a LRAM variance account to track the differences between actual and forecast lost revenue.

Distributors require a process to obtain pre-approval of input assumptions in order to obtain some regulatory certainty that their input assumptions and estimates for their CDM programs, which drive the calculation of the LRAM and SSM, are reasonable and acceptable to the regulator. Most of the experts agreed with the suggestion of the RP-2004-0188 Conservation Working Group, that input assumptions be pre-approved by the Board. The EDA agrees with most of the experts agreed that adjustments to input assumptions should be done prospectively, not retroactively. The sample list of pre-approved inputs in use in California provided by Mr. Heeney appears to be a good starting point for developing pre-approved inputs for Ontario.

Distributors require adequate incentives to encourage distributors to pursue CDM initiatives that are cost effective. Incentives will encourage distributors to be more innovative, and provide a strong motivation for them to divert some of their attention away from their traditional core activities by giving CDM a higher priority. When private industry promotes conservation, they do so for a profit motive. Distributors should not be expected to invest time and resources on CDM activities without the ability to obtain some benefit for undertaking the responsibility.

The EDA supports the "pays as you go" approach advocated by the most of the experts but would suggest that consideration be given to the longer term goal of moving to "flat rate pricing and customer bill savings" approach in the future.

Mr. Goulding noted that it would be more economically efficient to have a fixed charge for distribution services (Tr. Vol. 9 para. 538) and fixed charge more accurately represents distribution systems (Tr. Vol. 9 para. 539). A flat charge would allow a less administratively complex regulatory framework for CDM (Tr. Vol. 9 para. 567) and would create financial stability for distributors (Tr. Vol. 9 para. 570).

Chernick's description of the problems with fixed charges (Tr. Vol. 10 paras. 580-583) demonstrates a misunderstanding of the proposal being developed by Woodstock Hydro. Mr. Chernick assumes customers would move in and out of subclasses based on their consumption changes. In fact the fixed charge would be based on the physical characteristics of the connection to the customer that changes only on certain occasions for certain customers.

A move towards fixed charges would ensure distributors are not adversely affected by reduced energy consumption regardless of who promotes conservation initiatives.