ONTARIO ENERGY BOARD
2006 ELECTRICITY DISTRIBUTION
RATE HANDBOOK

DRAFT 2

10 JANUARY 2005

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Appendix D 2006 EDR Model

Appendix E Distribution Activities

Chapter 1

Introduction to the 2006 Handbook

1.0 Introduction

The 2006 Electricity Distribution Rates Handbook sets out how the Board generally intends to address applications for 2006 electricity distribution rates. The Handbook is intended to provide applicants with a straightforward process by which to prepare their applications for 2006 electricity distribution rates.

The 2006 Handbook is composed of guidelines and filing requirements. The Board is not bound by the guidelines. The specific filing requirements that are set out in the 2006 Handbook, however, are mandatory, and no application will be considered complete until all of these requirements are met.

It is open to the Board to consider alternative rate-making principles at the request of an applicant. Applicants should be aware, however, that applications which are not consistent with the 2006 Handbook will require a significant length of time to process. Evidence over and above that required in the 2006 Handbook will ~~w~~ be necessary to justify a departure from the 2006 Handbook methodology.

1.1 Application Components

The 2006 Electricity Distribution Rates Handbook is made up of the 2006 Handbook, and the 2006 rates spreadsheet model, referred to as the 2006 EDR Model. Taken together, these two components should provide a complete guide to the filing of an application for distribution rates for the 2006 rate year.

An application for rates in 2006 must consist of three parts:

- the description of the application
- the completed 2006 EDR model
- supporting schedules

1.) Description of the Application

The description of the application is a narrative summary of the application, intended to provide context to the data filed in the 2006 EDR Model. The content will be similar to

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what was included in the Manager's Summary in previous rate applications, which provided a narrative description.

An applicant should include in the description of the application any information that will assist the Board in understanding and assessing the application for rates. The content of the description of the application is described in more detail in Chapter 2.

2.) <u>2006 EDR Model</u>

The 2006 EDR Model is a series of spreadsheets in which the applicant enters the data required by the 2006 Handbook. The 2006 EDR Model includes a separate module, the 2006 OEB Tax Model, which is linked directly into the main 2006 EDR Model.

In Chapter 3, the 2006 Handbook outlines an approach for setting 2006 rates based upon the use of an adjusted 2004 historic test year. The 2006 EDR Model will calculate a revenue requirement based upon the data submitted.

As noted later in the 2006 Handbook, there have been few changes made to the cost allocation and rate design portions of the previous rate adjustment model (RAM). The 2006 EDR Model will allocate costs and produce a rate schedule based upon the data inserted by the applicant.

3.) <u>Schedules</u>

In a number of places in the 2006 Handbook, an applicant must complete and file supporting schedules. In general, these schedules will provide more detail about data that must be filed in the 2006 EDR Model.

Not every applicant will have to complete every schedule. Some schedules are required only if a distributor has certain programmes, or chooses to seek certain adjustments or amounts in the rate application.

A list of schedules is provided in Chapter 2, and the schedules are provided at the end of the chapters in which they are required.

1.2 <u>**Filing Date**</u>

Rate applications for 2006 must be filed no later than July 4, 2005. The Board anticipates that rate adjustments for 2006 will come into effect on May 1, 2006.

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Chapter 2

Description of the Application

2.0 Introduction

An applicant must file its rate application, including the completed 2006 EDR Model, in hard copy and in electronic format. The electronic version facilitates analysis and review. The hard copy, however, remains the official application, according to the Board's Rules of Practice and Procedure.

The competed 2006 EDR Model and the supporting schedules required by the 2006 Handbook are two components of the rate application. An applicant must also provide a description of the application, which is to include the requirements set out in this chapter. The content will be similar to what was included in the Manager's Summary in previous rate applications. An applicant must include in the description of the application any information that will assist the Board in understanding and assessing the application for rates.

An applicant is responsible for the completeness and accuracy of information submitted to the Board. The burden is on the applicant to demonstrate, through the evidence it provides, that the rates sought are just and reasonable.

2.1 General Information

2.1.1 Description of the Distributor

An applicant is to provide the following information:

- name of the distributor
- current licence number of the distributor
- mailing address
- key contacts: name, title, telephone number, e-mail, fax number

An applicant must also provide the following information about the distributor:

- community or communities served
- list of adjacent distributors
- characteristics of the service area: urban, suburban, rural, mixed

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- embedded or host distributor

2.1.2 Corporate Structure

The applicant must provide a corporate organization chart identified as Schedule 2-1. The chart is to show the parent, affiliate, and subsidiary companies, with their relationships to the distributor.

The applicant must also include a summary description of the nature of each affiliate's business, the products and services provided to, or received from, each affiliate, and the corporate services shared with the distributor.

2.1.3 Compliance with Licence

The description of the application should include a statement of whether or not the distributor is in compliance with the terms of its licence, if it is exempted from specific sections, or if it is in any way non-compliant.

Where there is non-compliance, the description should state the nature of the non-compliance, the reasons for it, and the status of efforts to become either compliant, or exempt.

2.2 <u>Description of the Application</u>

An applicant should submit a narrative summary of the application in order to provide a context for the data filed in the application. For consistency among all distributors, the applicant must format its description of the application by chapter. Several chapters in the 2006 Handbook require an applicant to provide specific information, and require supporting schedules to be filed. These schedules are listed below, for convenience. An applicant should refer to the relevant chapters for details as to what specific information is required in the description of the application

Chapter 2: <u>Description of the Application</u>

Schedules: 2-1 Corporate organization chart

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Chapter 3: Test Year and Adjustments

Schedules: 3-1 Tier 1 adjustments

3-2 Tier 1 non-routine/unusual adjustments
3-3 Tier 2 adjustments

Chapter 4: Rate Base

Schedule: 4-1 Capital expenditures

Chapter 5: Cost of Capital

Schedule: 5-1 Calculation of weighted average debt rate
5-2 Actual capital structure of distributor, and explanation for any variance

Chapter 6: Distribution Expenses

Schedules: 6-1 (*under Alternative 2*) Description and dollar value of incentive plan
6-2 Non-OMERS pension plans
6-3 Affiliate transactions and shared services

Chapter 7: Taxes/PILs

Schedules: 7-1 Sharing of tax exemptions
7-2 Loss carry-forwards

Chapter 8: Revenue Requirement

Schedules: 8-1 Derivation of base revenue requirement

8-2 Revenue from sources other than Board-approved rates and charges

8-3 Regulatory asset amortization

Chapter 9: Cost Allocation

Schedules: 9-1 Customer Classification
9-2 Allocation factors to customer classifications

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9-3 Non-default allocation factors to customer classifications

Chapter 10: Rates and Charges

Schedules: 10-1 Determination of fixed/variable splits
10-2 Unmetered scattered load
10-3 Time of use distribution rates
10-4 Transformer Ownership Allowance
10-5 Determination of loss adjustment factors
10-6 Distributed generation
10-7 Standby charges
10-8 Low voltage charges

Chapter 11: Specific Service Charges

Schedules: 11-1 Specific service charges: standard amounts
11-2 Specific service charges: standard formula and amounts

11-3 Specific service charges: revenue

Chapter 12: Other Regulated Charges

Schedules: None

Chapter 13: Mitigation

Schedules: *To be determined.*

Chapter 14: Comparators and Cohorts

Schedules: 14-1 Filing

Chapter 15: Service Quality Regulation

Schedules: 15-1 Service Quality and Reliability Performance 2002 to 2004

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Chapter 3

Test Year and Adjustments

3.0 Test Year and Adjustments

The methodology for the 2006 Handbook is based upon the principle of building rates from costs, using a test year derived from the applicant's 2004 (historical) audited financial statements, subject to the adjustments specified in this chapter.

There are two levels of adjustment: Tier 1 adjustments, which are **mandatory** for all applicants, and **optional** Tier 2 adjustments, which may be made by applicants meeting the criteria specified in this chapter.

Applicants not wishing to file on the adjusted historic test year basis, may file on a "forward" test year basis, with full supporting documentation.

An applicant **must** file on the basis of a forward test year if it wishes to make any adjustments to its application beyond those outlined in the Tier 1 and Tier 2 categories in this chapter.

Where any restatements and/or changes in accounting policy have occurred which affect opening 2004 balances, the data filed in the application is to be based upon the audited financial statements, incorporating only those changes that the applicant's auditor has accepted.

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.

3.1 Historical Test Year versus Future Test Year

The applicant may choose from three filing options:

Option 1: 2004 (historical) audited financial statements with **mandatory** adjustments, defined as Tier 1 adjustments.

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Option 2: In addition to the **mandatory** Option 1 adjustments, further **optional** adjustments, defined as Tier 2 adjustments, may be considered for applicants who meet the criteria specified for hardship.

Option 3: Forward test year with full supporting documentation commensurate with the nature of the application.

The guidelines in this section of the 2006 Handbook only relate to Options 1 and 2, outlined above.

An applicant filing under Option 3, the forward test year, will also be expected to provide all information that is required for Appendix D, the 2006 EDR Model. Information that is not specifically relevant to their applications (e.g. Tier 1 and Tier 2 adjustments) does not have to be filed, however.

Whichever option the applicant chooses, three years of historical supporting data - 2002, 2003, 2004 - must be included with the application, as set out in the 2006 EDR Model.

3.2 Test Year Adjustments

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

Option 1: Tier 1 Adjustments

Tier 1 adjustments are **mandatory** and serve two purposes:

1. To move the 2004 year-end closer to a "typical" year of capital investments, operations, and revenues through the use of non-routine unusual adjustments, applying to 2004 only. The nature of these adjustments, and the process for making them, is detailed below.

2. To allow for the limited subsequent year adjustments specified in the following table **only**. Applicants wishing to make any other post-2004 adjustments (e.g. for new labour contracts coming into effect in 2005) will be required to file on a forward test year basis.

Tier 1 adjustments are to be made in the form of debits or credits to the relevant 2004 year-end balance (i.e. distribution expense, rate base, or revenue). They should be entered into page ***X***, Schedule ***Y***, of the 2006 EDR Model.

Tier 1 adjustments will require minimum supporting documentation, except for non-routine/unusual adjustments.

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The mandatory Tier 1 adjustments to distribution expenses and to rate base are summarized in the following table, and are discussed in more detail, subsequently. Tier 1 revenue adjustments may also be required. These are described in Chapter 8.

<u>**Distribution Expenses**</u>	**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: <u>*Note*</u>*: 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*

<u>**Tier 1 Adjustments: Distribution Expenses**</u>

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1.) OEB annual dues and other regulatory agency costs

The applicant should adjust the 2004 base filing for the 2005 actual on Schedule 3-1. If the applicant is adjusting for regulatory agency costs other than the OEB annual dues, it should provide a breakdown of the total proposed adjustment and any necessary explanations.

2.) Pensions

The applicant should adjust the 2004 base filing for the 2005 actual on Schedule 3-1.

3.) Insurance

The applicant should adjust the 2004 base filing for the 2005 actual on Schedule 3-1.

4.) Non-routine/unusual adjustments

These would be of the kind discussed in more detail below, applicable to 2004 only, and exceeding a materiality threshold of 0.2% of total distribution expenses before PILs and adjustments.

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.*

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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.*

6.) <u>CDM and Smart Meters</u>

Placeholder in case any adjustments are required.

<u>Tier 1 Adjustments: Rate Base</u>

1.) <u>New transformer stations</u>

If the applicant anticipates that any new transformer stations and directly-associated assets (e.g. feeders) with an in-service date of 2005 are expected to come on-line, the rate base is to be adjusted to take such additions into account.

Distributors wishing to have any transformation-related assets included in the distribution rate base which would not be included in the definition of the distribution rate base, as specified in Appendix B (e.g. Account 1815 Transformer Station Equipment – normally primary above 50kV), should request in their applications that the Board, in its decisions on their applications, deem such assets to be distribution assets.

2.) <u>Retirements without replacement</u>

If the applicant anticipates that an asset will be retired without replacement in 2005, the rate base is to be adjusted to take such retirements into account, when the net book value of the retirement exceeds 0.2% of net fixed assets before adjustments.

3.) <u>Wholesale Meters</u>

The applicant should include its 2005 actual value for wholesale meters.

4.) CDM and Smart Meters

Placeholder in case any adjustments are required.

5.) Non-routine/unusual adjustments

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*

Non-routine/unusual Tier 1 Adjustments

The purpose of Tier 1 adjustments is to move audited 2004 results closer to a typical year of capital investments, operations, and revenues, to the extent possible.

The application review process will include a prudential review of the submitted 2004 numbers to assess their validity as a basis for 2006 rate-setting. Accordingly, the applicant should ensure that any material non-routine or unusual events that occurred in 2004 are adjusted for, using the non-routine and unusual adjustments.

Non-routine/unusual adjustments are defined as readily-known, identifiable, quantifiable, and verifiable occurrences, taking place in 2004 only, which exceed the materiality thresholds defined in the relevant sections of the 2006 Handbook. It is **mandatory** for the applicant to identify such adjustments, where applicable, and to incorporate them into the application.

Schedule 3-2 should be completed for all such 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,

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whereas Chapter 6 may allow full or partial recovery of unusual 2004 bad debt. Stakeholders are invited to address this issue in their arguments.

- natural disaster impacts (e.g. ice storm)

- mergers and associated costs

Mergers and acquisitions taking place after 2004 are to be dealt with outside of the 2006 rate-setting process and are not discussed in the 2006 Handbook.
If non-routine adjustments are necessary for 2004, the description of the application should include a statement to that effect.
If an applicant determines that an event which may appear to be non-routine or unusual should not be the subject of such an adjustment, the applicant should provide a full explanation in Schedule 3-2 as to why this is the case. For example, a significant increase in an expense item in 2004, which is expected to be sustained in subsequent years might not require an adjustment.

<u>Illustrative Example of a Non-routine/unusual adjustment</u>

In 2004, a utility experienced a record-setting “storm of the century” which did considerable damage to its network, but which is unlikely to be repeated in the immediate future.

As a result, the utility’s 2004 results show additional costs related to this storm that are not typical of the costs the utility is likely to incur in 2006. The utility should remove such costs through the non-routine/unusual adjustments mechanism.

For instance, assume the utility identifies $10,000 of incremental costs relating to the storm in Account 5020 Overhead Distribution Lines and Feeders – Operations Labour. These costs should be removed on page ***X***, Schedule ***Y***, of the 2006 EDR Model by entering a Tier 1 adjustment to the amount of $10,000 on the relevant line of the Distribution Expenses entry page.

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

In addition to the **mandatory** Tier 1 adjustments outlined above, applicants may also choose to apply for Tier 2 adjustments, which are **optional**. The purpose of Tier 2 adjustments is to restore both capital investments not made and distribution expenses not incurred due to one or both of the following circumstances:

- The applicant began the 1999 RUD process with negative returns.

- The applicant did not receive the second third of the market-adjusted revenue requirement increment.

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Unless the applicant meets one or both of the above criteria, the applicant is **not** eligible for Tier 2 adjustments. Even if the applicant is eligible for Tier 2 adjustments, however, it is the applicant's option as to whether or not it chooses to apply for them.

Tier 2 adjustments are not an entitlement. They represent the amount of distribution expenses and capital expenditures that the applicant believes it was not able to spend because of the above circumstances, but now wishes to spend.

In order for the Board to approve proposed Tier 2 adjustments, the applicant must do the following:

- demonstrate that it has suffered hardship as a result of one or both of the circumstances outlined above

- demonstrate that the proposed incremental distribution expenses and capital spending levels are justified by the hardship it has experienced, including how the applicant determined that these amounts are attributable to the two circumstances outlined above

- provide details on the activities that will be undertaken if the proposed incremental spending is approved, including specific details as to the nature of the envisaged activities and their timing on a monthly basis

Tier 2 adjustments will have two components: adjustments to distribution expenses, and adjustments to the rate base in order to achieve sustainable levels of expenses and capital on a going-forward basis.

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.*

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Illustrative Example of the Differences Between Alternatives 1 and 2

Assume a distributor did not receive the second third of the market adjusted revenue requirement increment and that this amount was $50,000.

Under Alternative 1, the distributor would be able to apply for a 2004 adjustment to either capital, expenses, or both, of not more than $50,000. The applicant would have to justify the proposed breakdown of the claimed recovery amounts between expense and capital.

Under Alternative 2, the distributor would be able to apply for an additional adjustment. If it is assumed that the applicant had not received $50,000 for three years related to the second third of the market-adjusted revenue requirement increment, the distributor could apply for a maximum $150,000 in additional adjustments to recover this prior years' shortfall. As is the case with Alternative 1, the applicant would have to justify the proposed breakdown of the claimed recovery amounts between expense and capital.

Tier 2 adjustments will be applied on a prospective basis.

Applicants wishing to make Tier 2 adjustments should complete Schedule 3-3.

Approvals of proposed Tier 2 adjustments, or of any portion thereof, will be subject to monitoring requirements. These requirements will include the filing of monthly reports with the Board during the period of the approved expenditures, confirming that they have taken place as stated in the applicant's filing, or if not, providing an explanation for the variance and the applicant's revised plans.

If the Board determines that the applicant is departing materially from the Tier 2 adjustment proposals approved in its application, the Board will establish deferral accounts, including interest, to be used to ensure that the applicant's rates are adjusted appropriately for any such departures at the time of its next planned rate adjustment.

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Schedule 3-1: Tier 1 Adjustments

This form is to be used for all Tier 1 adjustments, except for non-routine/unusual adjustments, for which Schedule 3-2 should be used.

1. Standard Distribution Expense Adjustments

This table should be completed for the three standard distribution expense adjustments, outlined below:

	2005 Actual (1)	2004 Actual (2)	Adjustment (3) (1) – (2)
OEB Annual Dues and Other Regulatory Agency Costs*			
Pensions			
Insurance			

* Applicants should provide a breakdown of costs being claimed, if they include cost recoveries other than OEB annual dues

Applicants should ensure that relevant information, sufficient to allow all parties to the proceeding to have a full understanding of the adjustments, is included in the description of the application.

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*

Schedule 3-2: <u>Tier 1 Non-routine/unusual Adjustments</u>

This form is to be used for Tier 1 Adjustments that are non-routine/unusual adjustments.

Please note that, although Tier 1 non-routine/unusual adjustments are non-specific by nature, they are nonetheless **mandatory** where required, and are only applicable to 2004.

If the applicant is not making any such adjustments, a statement to that effect should be incorporated into the description of the application.

<u>Non-routine/unusual Adjustments</u>

1. Please provide a detailed explanation of the nature of the adjustment that is being made.

   Please specify to which of rate base or distribution expenses it applies.

   Please include a detailed breakdown of the amounts of the adjustments made.

2. Please state why the applicant believes the adjustment is appropriate.

3. The materiality thresholds for adjustments of this kind have been established as 0.2% of the following amounts:

   - for distribution expenses: total distribution expenses before PILs and adjustments
   - for rate base: net fixed assets before adjustments

   Please confirm that the proposed adjustments exceed the relevant materiality thresholds.

4. Please specify any 2004 events that may appear to be non-routine or unusual, but which the applicant has determined should not be the subject of such an adjustment (e.g. a significant increase in an expense item in 2004 that is expected to be sustained in subsequent years) and provide a full explanation as to why the applicant believes this to be the case.

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

Approvals of proposed Tier 2 adjustments, or of any portion thereof, will be subject to monitoring requirements. These requirements will include the filing of monthly reports with the Board during the period of the approved expenditures, confirming that they have take place as stated in the applicant's filing, or if not, providing an explanation and the applicant's revised plans.

If the Board determines that the applicant is departing materially from the Tier 2 adjustment proposals approved in its application, the Board will establish deferral accounts, including interest, to be used to ensure that the applicant's rates are adjusted appropriately for any such departures at the time of its next planned rate adjustment.

Tier 2 adjustments are **optional**, unlike Tier 1 adjustments. To be eligible for Tier 2 adjustments, the applicant must have experienced one or both of the following circumstances:

- The applicant began the 1999 RUD process with negative returns.
- The applicant did not receive the second third of the market-adjusted revenue requirement increment.

1. Please confirm that the additional capital expenditures or distribution expenses proposed had to be postponed due to one or both of the two circumstances outlined for Tier 2 adjustments, and not for other reasons. If only one of the circumstances is applicable, please state which one.

2. Please state how the total amount being claimed is justified by the two circumstances outlined above (e.g. the amount of lost revenue that can be attributed to one or both of the above circumstances).

3.

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.

Chapter 4

Rate Base

4.1 <u>Definition of Rate Base</u>

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].*

Distribution assets are those associated with activities that enable the conveyance of electricity for distribution purposes. Such activities include operation and management of the distribution system, meter reading services, billing and collection services, and others.

Non-distribution assets are those associated with activities not falling within the above definition of distribution activities, including street lighting services, renting and selling of hot water heaters, electricity transmission, and others.

Appendix B provides more detailed information on distribution and non-distribution assets, and how non-distribution assets should be identified and removed from the rate base. The nature of any such removals should be specified. Appendix D, which contains the 2006 EDR Model, provides the details of these filing requirements.

Distributors wishing to have any assets included in the distribution rate base that would not be included in the definition of the distribution rate base, as specified in Appendix B (e.g. Account 1815 Transformer Station Equipment – normally primary above 50 kV), should request in their applications that the Board, in its decisions on their applications, deem such assets to be distribution assets.

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

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

Alternative 1: *at year-end*

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

…plus a working capital allowance, which 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. (See Appendix B for additional details.)

2004 net fixed assets, with the adjustments outlined in Chapter 3, would include the following items:

- amounts paid to other distributors or transmitters for capital projects, including contributions made to Hydro One for transmission upgrades (a list of the recipients and the amounts of these capital contributions should be included in the description of the application)

- wholesale metering upgrade costs to be included in metering assets

- interval meters

- shared assets for which the utility pays

- capital expenditures for Smart Meters and CDM projects

All revenue generated by joint use assets included in rate base should be included when determining the revenue sufficiency or deficiency.

Assets leased under capital leases are to be included in the rate base if they meet the Canadian GAAP standards for classification as a capital lease.

As outlined in Chapter 3, the applicant must file on the basis of **mandatory** Tier 1 adjustments, and also has the option, if it meets the specified criteria, of filing for additional Tier 2 adjustments. The filed rate base number, therefore, would be the base number from Appendix B, plus the adjustments outlined in Chapter 3.

4.2 Amortization Rates

The amortization rates outlined in Appendix C, Amortization Rates, are to be used for the purposes of the 2006 filings. An applicant who does not use the amortization rates listed in Appendix C must justify this departure and file the amortization schedules it proposes to use. The amortization study which supports these schedules should also be filed.

4.3 Capital Investments

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Applicants should complete Schedule 4-1, Capital Expenditures, which provides details on their 2004 capital investment programmes.

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)*

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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.

4.3.2 IT-related

The major capital expenditures related to IT initiatives (e.g. billing systems, SCADA systems, asset management systems, integrated resource systems, and similar expenditures) should be disclosed on Schedule 4-1. The materiality threshold for such disclosure is as outlined below.

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 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.

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.*

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.*

4.6 Contributed Capital

Contributed capital collected by the electricity distribution utilities on or after January 1, 2000 is not to be included in rate base. No return is earned on contributed capital collected on or after January 1, 2000, and the associated amortization expense is not charged to operating expenses.

Historical contributed capital included in rate base under the Ontario Hydro regulatory regime will remain in rate base and earn a return until these assets are fully depreciated. The depreciation expenses associated with this historical contributed capital will be charged to operating expenses until the assets are fully depreciated.

4.7 Treatment of Capital Gains and Losses

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4.7.1 Non-depreciable Assets Sold to a Non-Affiliate

The treatment of capital gains and losses on non-depreciable assets sold to a non-affiliate will be determined by the Board on a case-by-case basis, subject to the materiality thresholds outlined in Section 4.3.2. Capital gains and losses that fall below the materiality threshold will be shared between ratepayers and the shareholder on a 50:50 basis in determining the applicant's revenue requirement.

4.7.2 Depreciable Assets Not Sold to an Affiliate

The treatment of capital gains and losses on depreciable assets sold to a non-affiliate will be determined by the Board on a case-by-case basis, subject to the materiality thresholds. Capital gains and losses that fall below the materiality threshold will be to the credit or debit of the shareholder in determining the applicant's revenue requirement.

4.7.3 Assets Sold to an Affiliate

The treatment of non-depreciable and depreciable assets sold to an affiliate is as outlined above for each of the representative circumstances, that is, non-depreciable or depreciable. The materiality thresholds outlined in Section 4.3.2, however, will be applied to the value of the asset sold and not to the amount of the gain or loss on the sale.

Schedule 4-1: Capital Expenditures

Applicants must file detailed information on their 2004 capital expenditures in the following format. For any projects exceeding the materiality threshold, a detailed summary of the project should be attached to this form, outlining key information about it. This would include its purpose, its cost, its timing, and other information that the applicant believes would be relevant to the Board and other interested parties.

Project	$(000) Amount	In-Service Date

Intangible Plant

Distribution Plant

- land and land rights
- buildings, fixtures, and leasehold improvements
- distribution equipment (specify)
- meters

General Plant

- land and land rights
- buildings, fixtures, and leasehold improvements
- equipment (non-IT)
- IT equipment
    - billing systems
    - SCADA systems
    - GIS/CIS systems
    - hardware/software
    - other
- load management controls
- other (specify)

Other Capital Assets

- property under capital leases
- electric plant purchased or sold
- other (specify)

Total Capital Expenditures

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Chapter 5

Cost of Capital

Note: *This draft of the 2006 Handbook retains explanatory detail in Chapter 5 which may be removed in the final version.*

5.0 Introduction

Cost of capital refers to the costs incurred by a distributor in order to finance its operations, either by attracting and retaining investment from shareholders, or by raising debt.

There are three main components to the cost of capital, expressed in dollars or as a percentage:

- return on equity (ROE): the return that shareholders should have the opportunity to earn, assuming operations are normal and managed prudently, and considering the risk of the market, firm, or sector
- debt rate (DR): the cost of financing long-term debt, taking into account interest rates and the risk of the market, firm, or sector
- debt/equity ratio (D/E): the proportion of the firm's financial structure that is financed through debt, the remainder being financed through equity

In equity, there is no distinction between common shares and preferred shares.

Currently, short-term debt is ignored in the calculation of cost of capital. Applicable cost rates relating to the carrying costs of construction work in progress, amounts in deferral accounts, and certain defined regulatory assets are dealt with elsewhere in the 2006 Handbook.

The cost of capital is the weighted average percentage of the return on equity percentage and the debt rate percentage, as demonstrated in the following equation, where D is debt ratio, the percentage of the rate base that is (deemed) to be financed through debt; DR is debt rate; and ROE is return on equity:

$$\text{Cost of Capital} = D \times DR + (1 - D) \times ROE$$

The debt rate and the maximum allowed return on equity are updated for 2006 to reflect the forecast for the long-run (30-year) Government of Canada bond yield.

The equity risk premium is held at 3.80% (380 basis points).

There is no change in the structure of the size-related debt rate, other than the update for the current Long Canada Bond yield. The deemed debt/equity structure is also unchanged from what was used for the calculation of unbundled electricity distribution, from 2001 to the present.

The Board has approved the use of a mechanistic update of return on equity and size-related debt rate for the 2006 EDR process.

5.1 Maximum Return on Equity

The maximum allowed return on equity is based upon the initial set-up documented in Section 5 of Dr. Cannon's paper, "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities," December 1998.

Example of Methodology

Using the July 2004 *Consensus Forecasts*, the 3- and 12-month outlooks for 10-year Government of Canada bond yields were 5.1% and 5.5%, respectively, giving an average of 5.3%.

Taking actual Bank of Canada data for 10- and 30-year bond rates for all business days during July 2004, and averaging the daily differences between the two rates, gives an average difference of 0.51% (51 basis points).

The sum of these two averages is the forecast of the Long Canada Bond Rate (LCBR).

The equity risk premium used for the Ontario electricity distribution sector is set at 3.80% (380 basis points).

The maximum allowed return on equity, based upon July 2004 data, is the sum of the following numbers:

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average of 3- and 12-month *Consensus Forecast* outlook for 10-year Government of Canada bond rates	5.30%
average difference during July 2004, between 10- and 30-year Government of Canada bond yields	0.51%
implied equity risk premium	3.80%
maximum allowed return on equity	**9.61%**

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.

5.2 Debt Rate

The debt rate (DR) is based upon the forecast of the Long Canada Bond Rate (LCBR), and will be determined by the Board using the most current data available, at the time it releases its 2006 rate decision.

A mechanistic approach to the deemed, size-related, long-term debt rate calculation, is derived from the following formula:

$$DR_i = LCBR + x + \delta_i$$

- DR_i: deemed long-term debt rate for a utility in size category "i," as a proxy for business risk

- LCBR: Long Canada Bond Rate yield estimate for the period in question

- x: the premium commanded by financial lenders for long-term debt issued by a low-risk utility

- δ_i: a differential to reflect the incremental premium commanded by financial lenders for long-term debt rate issued for a utility in size category "i," over that for a low-risk utility

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:

Table 5.1
Size-Related Debt Rate Formula

Utility Size	Rate Base	Deemed Capital Structure		Deemed Debt Rate (DR)	δ_i	x	LCBR
		Debt (D)	Equity (1-D)			0.60%	5.81%
Large	> $1.0 billion	65.00%	35.00%	6.41%	0.00%		
Medium - Large	$250 million - $1.0 billion	60.00%	40.00%	6.51%	0.10%		
Medium - Small	$100 million - $250 million	55.00%	45.00%	6.61%	0.20%		
Small	< $100 million	50.00%	50.00%	6.86%	0.45%		

The 2006 EDR Model will select the deemed debt rate based upon the distributor's rate base.

<u>Weighted average debt rate</u>

The debt rate used to calculate the cost of capital will depend upon the utility's cost of actual debt, and whether that debt is held by a third party, or by an affiliated firm.

The applicant should complete Schedule 5-1 to determine the weighted average debt rate.

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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.*

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

The utility has a rate base of $125 million and a deemed debt 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.

5.3 Capital Structure

Applicants will use the deemed debt/equity structure, as shown in Table 5.1, to establish the revenue requirement for 2006 distribution rates. There is no adjustment for short-term debt, and there is no distinction made between common equity and preferred shares.

In Schedule 5-2, a distributor is required to show its actual capital structure (debt/equity ratios) for 2004 based upon shareholders' equity, preferred shares, and debt. These numbers, typically, are taken or derived from the utility's 2004 audited financial statements or similar records.

Where the actual debt/equity deviates from the deemed debt/equity structure, given the utility's size, by more than ten percentage points, the applicant must provide an explanation as to why the actual debt/equity structure is different, in Schedule 5-2.

5.4 Working Capital Allowance

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.

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.*

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Schedule 5-2: Actual Capital Structure of the Distributor

		Utility Capital Structure		
Line	**Particulars**	**($000)**	**(%)**	**Cost Rate**
(1)	Long-Term Debt			
(2)	Short-Term Unfunded Debt			
(3)	Total Debt			
(4)	Preferred Shares			
(5)	Common Equity			
(6)	Total Rate Base			

(3) = (1) + (2)

(6) = (4) + (5) + (3)

D = (3) / (6)

Explanation

Where the distributor's actual capital structure deviates from the deemed capital structure (Table 5-1), given the distributor's size, by more than ten percentage points, the distributor should provide a brief description of why this deviation exists, and why the distributor feels that its actual capital structure is appropriate (e.g., what circumstances, such as growth, have been factors, and whether or not the actual structure will result in increased cost of capital or financial risk).

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Chapter 6

Distribution Expenses

6.0 <u>Introduction</u>

<u>Use of 2006 Handbook guidelines</u>

Compliance with the 2006 Handbook guidelines set out below regarding distribution expenses will help to establish the reasonableness of the 2004 amounts filed in support of the determination of 2006 revenue requirements.

<u>General requirement for three years of supporting data</u>

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

Significant variances in the level of expenses between years should be explained in the description of the application. Circumstances that may affect the comparability of any of the three years of cost data filed, such as a change in accounting policies, should also be explained in the description.

<u>Level of Account Detail</u>

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)***

<u>Adjustments to 2004 Expenses</u>

Guidelines and requirements for supporting documentation for Tier 1 and Tier 2 adjustments to 2004 historic test year distribution expenses are outlined in Chapter 3. Adjustments are to be entered on ***Tab_Distribution Expense with Adj of the 2006 EDR Model***.

6.1 Definition of Distribution Expenses

6.1.1 Non-distribution adjustments

Only those expenses that relate to the provision of distribution services will be allowed for the calculation of the applicant's 2006 revenue requirement.

Distribution expense data will be filed in aggregated groupings for 2002, 2003, and 2004, and will be separated into distribution and non-distribution amounts on ***Tab_Trial Balance of the 2006 EDR Model***.

6.1.2 Definition of distribution expenses

Expenses associated with activities that enable the conveyance of electricity for distribution purposes are to be included in the applicant's 2006 revenue requirements.

6.1.3 List of distribution expense accounts

Appendix E sets out a list of APH accounts that are considered to be distribution expenses for the purposes of determining 2006 revenue requirement.

CDM Placeholder: *Account 5415 Energy Conservation may be referenced for use.*

6.2 Detailed Reporting for Specific Distribution Expenses

Review of the reasonableness of some specific distribution expenses requires disclosure of additional information. Detailed reporting requirements are outlined in the following sections.

Portions of certain expenses may be deemed unrecoverable for the determination of 2006 revenue requirements. These particular treatments are also outlined below.

Where numerical data must be filed to support specific distribution expenses, including any non-recoverable amounts, it will be entered on ***Sheet_Specific Distribution Expenses of the 2006 EDR Model***, unless otherwise noted.

6.2.1 Insurance Expense

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Minimum filing requirements

To be entered on Tab_Specific Distribution Expenses
All applicants are to file insurance expenses recorded for the years 2002, 2003, and 2004.
For those distributors with third party insurance, insurance expenses will consist of premiums and adjustments.

Where insurance premiums are paid to third parties, the following additional data is required:

- number of insurers
- type of insurance purchased
- premium costs per type of insurance

For those distributors with self-insurance, insurance expenses will consist of self-funded claims and any changes in reserves recorded as expense.

Where distributors self-insure, information about the organization and the operation of the self-insurance plan must be provided in the description of the application.

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.*

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.

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Minimum filing requirements

To be entered on Tab_Specific Distribution Expenses

1. All bad debt expense as reported in Account 5335 for the years 2002, 2003, and 2004, is to be reported, segregated by customer class.
2. Disclosure of all individual material bad debt occurrences included in the 2004 bad debt expense, as recorded in Account 5335.
   Disclosure should include the dollar value of the bad debt occurrence and a brief explanation of the circumstances.

   Materiality is defined as, an amount exceeding 0.2% of the total 2004 distribution expenses. The applicable materiality value will be calculated automatically within the 2006 EDR Model.

3. Applicants should explain in the description of the application the rationale behind including all or part of a material 2004 bad debt occurrence (e.g. bankruptcies) in the 2006 revenue requirement.

6.2.3 Information Technology Expenses

There is no single APH account that tracks IT-related expenses. In the description of the application, therefore, the applicant must include a description of its organization for IT services (including any outsourcing), and its methodology of recording IT expenses. For example, are some IT-related expenses included in engineering or in billing expense?

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

All data required for Section 6.2.4 will be entered on ***Tab: Specific Distribution Expenses of the 2006 EDR Model***.

Advertising expenses

Advertising expenses incurred for the sole purpose of promoting corporate branding or image are not to be included in determining the applicant's 2006 revenue requirement.

Minimum Filing Requirements

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

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Political contributions

Political contributions in the form of cash donations to political parties are not to be included in determining the applicant's 2006 revenue requirement.

Minimum Filing Requirements:

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

Employee dues

Annual fees or dues for employee memberships in organizations that are recreational or social in nature are not to be included in determining the applicant's 2006 revenue requirement.

Employee dues or fees related primarily to health and fitness are recoverable, provided that the same are generally available to all categories of employees.

Minimum Filing Requirements

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

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.

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.*

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Research and development

Research and development expenditures intended to benefit the applicant's ratepayers will be included in the determination of the applicant's 2006 revenue requirement. The description of the application should provide an explanation of the nature and amounts of such expenditures, and how they will benefit the applicant's ratepayers.

6.2.5 Employee Total Compensation

1. Reasonableness of expense

Applicants must demonstrate that the total compensation paid to its employees, part of which may be capitalized rather than expensed, is reasonable for recovery in the calculation of 2006 revenue requirements.

Total compensation includes the following items:

- base salary or wages earned
- overtime premiums paid
- value of benefits received that are paid for by the employer
- performance incentive payments received

2. Minimum Filing Requirements

To review the reasonableness of the applicant's total compensation expense, information is required on the number of employees and compensation levels.

Required data are to be provided in ***Tab_Employee Compensation in the 2006 EDR Model***.

The applicant is to provide three years of historical data (2002, 2003, and 2004) for the following four broad categories of distributor employees and contract workers:

- executive: CEO, COO, VP(s), General Manager(s), Director(s)
- management: operational, middle, and supervisory managers
- non-unionized: positions not included in union bargaining units that have no supervisory or management responsibilities
- unionized: positions that are part of a union bargaining unit

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.*

Required Information Disclosure

The information to be disclosed in aggregate for each category of employees is as follows:

- average yearly wage
  - segregated into base wage and overtime
  - wage: all earnings, excluding incentives and benefits, which are to be reported separately, below
- average yearly incentive
  - incentive: those amounts paid on a corporate incentive or bonus plan
- average yearly benefits
  - benefits: those amounts the applicant deems as employee benefits related to compensation
- number of full-time equivalents (FTEs)

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.*

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*

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6.2.6 Pensions and Post-retirement Benefits

Pensions: OMERS members

Applicants whose employees are members of the Ontario Municipal Employees Retirement System (OMERS) pension plan must provide the following information.

Minimum Filing Requirements

Applicants must provide OMERS pension premiums and adjustments expense for the years 2002, 2003, and 2004 on ***Tab_Specific Distribution Expenses in the 2006 EDR Model***.

Pensions: Non-OMERS members

Distributors whose employees are not members of OMERS may fund and administer their own pension plans and may incur pension expenses.

Minimum Filing Requirements

Applicants that are not members of OMERS, including those with distributor-owned and -administered pensions, must provide the following information in Schedule 6-2.

- cash versus accrual valuation
- “smoothing” methods
- eligibility by employee groups
- summary of performance for each plan

Post-retirement benefits

Expenses recorded for these benefits will vary, and, if reasonable, will be allowed for recovery in the 2006 revenue requirement.

In 2000, the CICA (see Section 3461) recommended changing from the cash method, to the accrual method of accounting for post-retirement employee benefits.

Minimum Filing Requirements

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The applicant must provide the following information in the description of the application:

- current accounting treatment of post-retirement benefits
    - e.g. cash versus accrual
    - e.g. review period frequencies
- treatment of past changes in accounting policy regarding post-retirement benefits, and any related one-time expenses, including amortization policy
    - e.g. change from cash basis, to accrual basis
- treatment of changes in actuarial value in post-retirement benefits
- disclosure of any plans that do not follow the current CICA accounting rules for regulatory purposes, and explanation for the alternative treatment

6.2.7 Distribution Expenses Paid to Affiliates

<u>Affiliate transactions</u>

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.

Distribution expenses incurred through the purchase of services or products from affiliate companies ("affiliate transactions") must be documented and justified as part of the 2006 revenue requirement.

<u>Minimum Filing Requirements</u>

Distributors must file the following information for the years 2002, 2003, and 2004.

Where reported distribution expenses are incurred through affiliate transactions, the following information is to be included in Schedule 6-3 (a) **(*to be written*)**:

- identity of each affiliate transacting with the applicant
- summary of the nature of the activity transacted with each affiliate
- annual dollar value, in aggregate, of transactions with each affiliate

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- identify whether a market-based pricing or a cost-based pricing was used for each transaction

- description of general methodology used in determining prices
  - e.g. summary of the tendering process, where market-based pricing was used
  - e.g. summary of the approach, where cost-based pricing was used

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.*

Shared services

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Where distribution expenses are incurred through the sharing of services or resources with affiliates of the applicant, the following information is to be included in Schedule 6-3 (b):

- types of services: finance, IT, office space, etc.

- total annual dollar value, by service
- rationale and summary of cost allocators used for shared costs, for each type of service (square footage, computers, headcount, etc.)

Distributors should review APH Article 340 and the ARC when justifying their expenses for shared services.

Schedule 6-1: <u>Employee Incentive Plan Expense</u>

Entire Schedule Contested

<u>Minimum Filing Requirements</u>

The questions below must be completed where a distributor has included in its application expenses in respect of any employee incentive plan.

1.) Description

Provide a general description of each incentive compensation plan.

2.) Performance Measures

Briefly describe the specific performance measures for each employee incentive plan. *[Identify whether the applicant considers each performance measure primarily to benefit shareholders (e.g. increase in share value) or ratepayers (e.g. reduction in distribution expenses).]*

3.) Annual Cost(s)

List the total annual dollar amount of the incentive compensation paid under each plan, and provide a breakdown between the shareholder-related sub-component and the ratepayer-related sub-component.

Question: *Information to be provided for 2002, 2003, and 2004, to be consistent with general provision of three years of historical data?*

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Schedule 6-2: Non-OMERS Pension Expense

Minimum Filing Requirements

The table below must be completed where a distributor has included in its application pension expenses paid on behalf of any employees that are not members of the Ontario Municipal Employee Retirement System, including any distributor-owned and – administered pension plans.

For the Year 2004

Plan	Employees	Performance	Valuation	Smoothing
Name non-OMERS Plan 1	Describe eligibility by employee groups.	Summarize annual performance for each plan.	Cash or accrual?	Describe any “smoothing” methods used.
Plan 2, etc.				

Question: *Information to be provided also for 2002 and 2003, to be consistent with general provision of three years of historical data?*

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Schedule 6-3 (a): Distribution Expenses Paid to Affiliate(s)

Minimum Filing Requirements

The table and questions below must be completed where a distributor has included in its application distribution expenses paid to an affiliate(s).

For the Year 2002

Affiliate Names	Activity	Value	Basis Pricing
Affiliate X	Describe transaction(s) with Affiliate X.	List annual aggregate $ value of amounts paid to Affiliate X.	Did affiliate use market-based pricing or cost-based pricing?
Affiliate Y, etc.			

For the Year 2003

Affiliate Names	Activity	Value	Basis Pricing
Affiliate X	Describe transaction(s) with Affiliate X.	List annual aggregate $ value of amounts paid to Affiliate X.	Did affiliate use market-based pricing or cost-based pricing?
Affiliate Y, etc.			

For the Year 2004

Affiliate Names	Activity	Value	Basis Pricing
Affiliate X	Describe transaction(s) with Affiliate X.	List annual aggregate $ value of amounts paid to Affiliate X.	Did affiliate use market-based pricing or cost-based pricing?
Affiliate Y, etc.			

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<u>Question 1</u>

Please provide a description of the general methodology used to determine the price(s) paid to affiliate(s).

<u>Example</u> Where market-based pricing was used, summarize the tendering process. Where cost-based pricing was used, summarize the approach followed.

<u>Question 2</u> ***(contested)***

If cost-based pricing was followed, please explain if, and how, the absence of a market was established.

Explanation.

<u>Question 3</u> ***(contested)***

Where cost-based pricing was used for the service or goods provided by the affiliate(s) to the applicant, list the actual costs of the affiliate.

List the names of the affiliate(s) and the actual annual (aggregate or not?) costs incurred by the affiliate in providing the services or goods in question to the applicant.

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Schedule 6-3 (b): Distribution Expenses Incurred Through Sharing Services with Affiliate(s)

Minimum Filing Requirements

The table below must be completed where the applicant incurs distribution expenses through the sharing of services or resources with an affiliate(s).

For the Year 2002

Affiliate Name(s)	Activity	Value	Basis Allocation
List the shared service(s) provider: Affiliate X	Describe the service(s) or resource(s) provided by Affiliate X.	List annual $ value, by service	For each type of shared cost, provide a summary of the cost allocator(s) used, and the rationale.
Affiliate Y, etc.			

For the Year 2003

Affiliate Name(s)	Activity	Value	Basis Allocation
List the shared service(s) provider: Affiliate X	Describe the service(s) or resource(s) provided by Affiliate X.	List annual $ value, by service	For each type of shared cost, provide a summary of the cost allocator(s) used, and the rationale.
Affiliate Y, etc.			

For the Year 2004

Affiliate Name(s)	Activity	Value	Basis Allocation
List the shared service(s) provider: Affiliate X	Describe the service(s) or resource(s) provided by Affiliate X.	List annual $ value, by service	For each type of shared cost, provide a summary of the cost allocator(s) used, and the rationale.
Affiliate Y, etc.			

Affiliate Relationship Code ***(contested)***

The applicant must provide a general explanation of how they followed the transfer pricing and shared services rules in the Affiliate Relationships Code.

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Chapter 7

Taxes / PILs

Note: *This draft of the 2006 Handbook retains explanatory detail in Chapter 7 which may be removed in the final version.*

7.1 Rules and Principles

The goals of the 2006 tax filing guidelines are to allow recovery of the distribution-only tax payable expected to be incurred by the distributor, with consideration to be given to regulatory fairness and administrative simplicity.

The 2006 OEB Tax Model and its principles will only be applicable to the 2006 rate year. The Board has not determined the process for the 2007 rate year, including whether or not the tax calculation will be revisited for that rate year. The Board has decided, however, that rebasing will be allowed in 2008, and so it is assumed that the tax model and its principles will be revisited as part of future rates processes no later than 2008.

This tax model has been designed for a distributor using the historical test year basis. Distributors filing on an historical test year basis must use the 2006 OEB Tax Model. Distributors filing on a forward test year basis do not have to use the 2006 OEB Tax Model, but must file an equivalent level of detail. The principles set out below, however, remain applicable to all applicants.

The 2006 regulatory tax calculation, as set forth in the 2006 Handbook and in the 2006 OEB Tax Model, is guided by the following principles:

7.1.1 General Principles Underlying the 2006 Tax Calculation

Application of 2006 Handbook and 2006 OEB Tax Model to all distributors

Most Ontario distributors will pay income and capital taxes in the form of section 93 proxy tax payments (PILs) to the Province. A small number of distributor(s), however, may pay section 89 proxy taxes, or as taxable corporations be subject to normal provincial and federal taxation.

A distributor required to pay PILs under section 93 of the Electricity Act must complete the 2006 OEB Tax Model without amendments. Any distributor submitting its own tax filing calculation, as well as the 2006 OEB Tax Model, will, in that separate calculation, follow the same basic principles and level of detail outlined in the 2006 Handbook and set forth in the 2006 OEB Tax Model. Any variations from the 2006 OEB Tax Model must be identified and described in the description of the application.

Distributors not required to pay PILs under section 93 shall do the following:

- describe in the description of the application the basis of their tax or PILs payments

- complete the 2006 OEB Tax Model with such changes as are necessary, while remaining consistent with the principles and the level of detail outlined in this 2006 Handbook

- explain all such changes to the 2006 OEB Tax Model in the description of the application

Prudent management of taxes

All distributors are allowed and expected to take prudent steps to manage their tax costs with reasonable diligence, as they would with other distribution expenses.

Regulatory taxes payable method

The tax amount included in rates is based upon taxes expected to be actually payable as a result of operating the distribution-only business, rather than upon taxes calculated for accounting purposes. Future/deferred taxes will not be recovered through rates as a result of this filing.

The 2006 OEB Tax Model estimates regulatory taxes payable. It takes into account the standard format of corporate tax returns to be submitted to tax authorities.

Applicants may wish to review their filed and assessed 2004, and their estimated 2005, Federal T2 and Ontario CT23 tax returns, before starting to complete the 2006 OEB Tax Model.

Use of historical data and future estimates to calculate 2006 tax expense

Revenues, expenses, capital items, and all other operating numbers are calculated using the 2006 EDR Model, based upon 2004 historical data, plus or minus allowed or required adjustments.

The 2006 OEB Tax Model starts with these results, then requires specific additional adjustments to project the PILs expected to be payable in 2006. The 2006 OEB Tax Model automatically includes data from the 2006 EDR Model.
Distributors must make the adjustments described in the 2006 Handbook and in the instructions to the tax model. The tax model then automatically calculates the forecast PILs amount and its components.

Tax rates and exemptions to be used in the 2006 EDR Model

The 2006 OEB Tax Model and the 2006 Handbook guidelines relating to PILs are based upon tax rates and rules that, as of April 1, 2005, are reasonably expected by the Board to be in effect during the 2006 rate year.

If there are any changes to tax rates or rules after April 1, 2005 and prior to filing the 2006 OEB Tax Model that should be incorporated into the distributor's tax calculations, the Board will issue a supplementary communication to that effect, amending the 2006 OEB Tax Model and/or the guidelines in the 2006 Handbook.

PILs tax administration and tax rulings

To calculate the tax payable/recovery to be allowed in the 2006 revenue requirement, distributors must follow the Board's regulatory tax principles set out in the 2006 Handbook and in the 2006 OEB Tax Model.

If a specific tax ruling or assessment policy applies to the distributor in a manner inconsistent with the 2006 OEB Tax Model, a summary of the ruling/policy shall be disclosed in the description of the application. As well, the distributor must disclose relevant information if it has objected to the tax ruling or assessment policy where the effect of the dispute would be a significant change in taxes due. The applicant's initial 2006 tax payable filing must account for the tax effect of the ruling or policy.

As part of the application's approval, the Board will determine whether to approve any suitable variation in the regulatory tax calculation or to establish a variance account.

True-up of 2006 actual taxes paid to taxes recovered in rates

There are five general categories of factors that can cause variances between actual and projected taxes:

A. Tax driven factors:
    - Changes in tax laws or regulations after the distributor's rates have been set.
    - Changes in the general interpretation or assessing policies of the Ministry of Finance
    - Reassessment of the distributor for years prior to 2006 which affect its UCC, loss carry-forwards, or other balances at the beginning of 2006.

B. Operations driven factors:
   - Actual mix of types of expenses, capital expenditures and other components of the tax calculation that differ from the forecast mix and type of those adjustments.
   - Actual earnings are more or less than forecasted earnings for the rate year

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.

<u>Tax re-assessments</u>

The true-up of 2006 taxes relating to re-assessments of taxation years ending prior to May 1, 2006, as set forth above, deals only with the impact on 2006 taxes of those re-assessments.

The impact on the prior year taxes of those re-assessments should be credited or debited to existing Account 1562, if applicable, to be dealt with as determined by the Board in a separate, generic proceeding or decision relating to that regulatory asset. The issue of whether interest and penalties should be included may be dealt with in that proceeding.

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Account 1562 will remain available for such entries until all re-assessments of those prior years have been received, or the years have become statute-barred.

No amount of tax relating to any prior year shall be included in rates for 2006, except pursuant to that separate, generic proceeding or decision.

7.1.2 Principles Applicable to Specific Components of the Calculation

7.1.2.1 Regulatory assets and liabilities

Recovery of PILS will not be allowed to the distributor with respect to PILS on recovery of regulatory assets. All regulatory assets recoveries, therefore, that are included in projected 2006 net income (line ***XX*** of the 2006 EDR Model) shall be deducted on line ***XX*** of the 2006 OEB Tax Model. Similarly the cost or regulatory assets included in losses carried forward are adjusted at line XX of the OEB Tax model.

Parallel adjustments for any regulatory liabilities must be made at line xx of the 2006 OEB Tax Model.

The OEB has dealt with the recovery of regulatory assets elsewhere in the handbook. The adjustments are necessary to exclude these items in the OEB Tax model.

7.1.2.2 Non-recoverable and disallowed expenses

Sources:

There may be some distribution-only expenses incurred by distributors that are deductible for general tax purposes, but for which recovery in approved 2006 distribution rates is partially or fully disallowed.

The 2006 OEB Tax Model addresses both non-recoverable and disallowed expenses. Specifically, the following are addressed:

- non-recoverable expenses known and taken into account at time of filing the 2006 EDR Model, for example, in respect of any expense disallowed under Chapter 6, but which will still be paid by the applicant

- any distribution expenses disallowed after regulatory review, so that to capture the tax impact of such disallowed expenses, the 2006 EDR Model will need to be re-run using approved figures

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

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.

Eligible Capital Expenses (ECE):

Maximum amortization of ECE must be claimed in computing taxes payable for purposes of the 2006 OEB Tax Model.

There are two issues regarding the regulatory tax treatment of ECE.

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

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

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Adjustment to fair market value at October 1, 2001 was required by the Ministry of Finance for tax purposes only. No adjustments to rate base were made for regulatory purposes.

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.*

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

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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.

Charitable donations:

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***

7.1.2.3 Capital gains and losses on disposition of distribution assets

If the distributor anticipates any gain or loss on disposal of distribution assets in 2006, the amount of the accounting gain or loss must be deducted from, or added to, income on line ***XX***.

Any portion of gain that has an impact upon capital cost allowance will be dealt with in the calculation of capital cost allowance elsewhere in the 2006 OEB Tax Model.

Any portion that generates a taxable capital gain or allowable capital loss will be dealt with in the 2006 OEB Tax Model in the same way that the accounting gain or loss is allocated between ratepayers and distributors (see Section 4.7). For example, if 50% of the accounting capital gain is allocated to the distributor, then 50% of that amount (i.e. 25%) should be entered on line ***XX*** of the 2006 OEB Tax Model.

The distributor should calculate the taxable capital gain or allowable capital loss under Federal T2 Schedule 6, and should retain the back-up calculation for regulatory purposes.

7.1.2.4 Sharing of tax exemptions

To provide an over-all sharing of tax exemptions between a corporate group of which the distributor is a member, or within a single corporate entity that provides both distribution and non-distribution services, the applicant must do the following when completing the 2006 OEB Tax Model:

i.) If the distributor is the only regulated utility in the corporate group, all of the LCT exemption shall be allocated to the distributor.

If the distributor is a member of a larger corporate group that includes other regulated utilities, the corporate group must allocate the federal Large Corporation Tax (LCT) exemption for 2006 to the distributor and other regulated entities within the corporate group, if any, on a reasonable basis, which basis must be disclosed on Sheet XX.

No amount of the LCT exemption shall be allocated to an unregulated member of the corporate group.

ii.) If the distributor is a member of a larger corporate tax group, the corporate group must allocate the 2006 provincial capital tax exemption, including both regulated and unregulated entities, as explained below.

As required for tax purposes, the provincial capital tax exemption must be pro-rated within the corporate group based on paid up capital amounts.

Applicants who do not anticipate significant changes in corporate capital mix can use their expected 2004 allocation as a proxy. Other applicants must file Schedule 7-1 in which they explain and justify their choice of allocation.

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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.*

7.1.2.5 Loss carry-forwards

The term loss carry-forward in this section refers to loss carry forwards as adjusted elsewhere in this chapter.

Distributors expecting to have any loss carry-forwards still available on January 1, 2005 must disclose the amount of those loss carry-forwards in the 2006 OEB Tax Model, project the amount that will still be available on January 1, 2006, and apply them in full to reduce the taxable income calculated in the 2006 OEB Tax Model.

These amounts are to be entered on Sheet XX.
The projection shall be based upon the following:

- the actual loss carry-forwards, as of January 1, 2005, plus or minus
- an estimate of any additional losses, or application of losses, in 2005

The result is the estimate of the loss carry-forward remaining on January 1, 2006.

Any stub period from January 1 through April 30, 2006 will be ignored. It will be assumed that any loss carry-forwards available on January 1, 2006 will still be available on May 1, 2006.

If a distributor has within its legal entity a business other than a distribution business, loss carry-forwards must be allocated between the distribution and the non-distribution business on a reasonable basis. The applicant shall include in Schedule 7-2 a description and justification of that allocation method and calculation.

7.1.2.6 Loss carry-backs

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No adjustment for loss carry-backs is permitted, since the OEB Tax Model estimates 2006 PILs.

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.*

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The applicant shall then assume that it has new additions to each class in 2005 equal to the following:

- the capital expenditures (i.e. new additions) to each class in 2004

- any Tier 1 and Tier 2 allowed capital adjustments relating to 2005, such as transformer stations, to the extent that they are higher than the 2005 additions used above

The half-year rule shall be applied to the calculation of CCA for all of the new additions in 2005.

After adding these new additions, 2005 CCA will be calculated and deducted, resulting in the new Undepreciated Capital Cost (UCC) as of January 1, 2006.

The distributor shall then assume that it has new additions to each class in 2006 equal to the new additions in 2005 - plus incremental Tier 1 and Tier 2 adjustments relating to 2006, if any are permitted - and add them to get the Reduced UCC before CCA. Apply the half year rule to 2006 additions.

The CCA for the 2006 OEB Tax Model will be calculated for each class on the Reduced UCC Balance.

The steps above are to be documented in Sheet **XX** of the 2006 OEB Tax Model.

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

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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.

7.1.2.9 Overlapping year-ends

The 2006 rate year runs from May 1, 2006 to April 30, 2007. The rate year is not contiguous with the calendar tax year. In order to calculate the approved regulatory tax payable for the 2006 rate year, however, the rate year will be assumed to be the same as the tax year. Any stub period issues, therefore, (e.g. loss carry-forwards or CCA) will be ignored when completing the 2006 OEB Tax Model.

The only exception to this principle is in the tax rates to be applied. All changes to tax rates anticipated during the 2006 rate year, at the time that the 2006 Handbook is issued, have been taken into account by simple pro-ration, ignoring income, in the rates built into the 2006 OEB Tax Model. No further action by distributors is required.

7.1.2.10 Estimating taxable capital

In order to calculate 2006 regulatory Ontario Capital Tax and the federal LCT, the applied-for 2006 rate base (see ***XX*** 2006 RAM) should be used as the proxy for taxable capital. The intention is to allow a reasonable regulatory estimate of the tax payable, but not require distributors to forecast fully their 2006 balance sheets.

The applicant has the option of substituting its estimated 2006 taxable capital for the rate base proxy. In such cases, the following information must be provided:

- full details of the capital tax calculation, including balance sheet assumptions
- the estimate calculated using rate base as a proxy

The 2006 OEB Tax Model incorporates the estimated 2006 dollar taxable capital exemptions.

The 2006 OEB Tax Model adjusts for differences between book figures and tax figures for capital tax purposes on Sheet XX.

7.1.2.11 Ontario Corporate Minimum Tax

The 2006 regulatory tax calculation does not include the Ontario Corporate Minimum Tax. As this Tax can be carried forward for ten years, it is expected that distributors will recover this tax as they become taxable.

7.1.2.12 Non-distribution elimination

Sheet ***XX*** of the 2006 OEB Tax Model requires that the applicant exclude any non-distribution costs and revenues. This elimination must be consistent with the definition of distribution-only activity contained within the 2006 Handbook.

7.1.2.13 Tax credits

Back-up calculations must include an estimate of any tax credits reasonably expected to be claimed in 2006, such as research and development credits.

7.1.2.14 2006 OEB Tax Model Calculations

The 2006 OEB Tax Model calculates the estimated 2006 PILs/taxes automatically once all input parameters have been entered, in accordance with the 2006 Handbook and the instructions in the 2006 OEB Tax Model.

In the process of estimating 2006 PILS/taxes, the following occurs:

- 2006 tax rates applicable to the particular distributor are calculated on the tax rates spreadsheet.

- The 2006 OEB Tax Model automatically subtracts federal surtax from the amount of federal Large Corporations Tax (LCT) due, as required.

- The 2006 OEB Tax Model will gross-up income tax, as required, calculating from 2006 regulatory income tax divided by (1 – applicant's 2006 tax rate).

- The 2006 OEB Tax Model will gross-up federal LCT, net of the applicable federal surtax, as required, calculating from the net LCT divided by (1 – applicant's 2006 tax rate).

- The 2006 OEB Tax Model will not gross-up Ontario Capital Tax, as the item is deductible for tax purposes.

- The federal surtax on income in the income tax rates is included for gross-up, as the surtax on incremental income is generally displaced by the LCT until the LCT is completed phased out by 2008.

  The total amount of corporate income taxes (as grossed up at line ***XX***) and LCT (as grossed-up at line ***XX***), and Ontario Capital Tax, is included in the main 2006 EDR Model at Sheet ***XX***, as the 2006 regulatory tax for recovery in 2006 distribution rates.

7.1.2.15 Placeholder: Impact of on PILs calculation

- *Tax implication may be material but not enough information to address this issue, at this time*

- *should be reviewed when the 2006 Handbook and the 2006 EDR Model are finalized, after the Hearing*

7.1.2.16 Placeholder: Impact of Smartmeters on PILS calculation

- *tax implication may be material but not enough information to address this issue, at this time*

- *should be reviewed when the 2006 Handbook and the 2006 EDR Model are finalized, after the Hearing*

7.1.2.17 Interest capitalised for accounting, but deducted for tax purposes

The applicant must identify the amount of any interest capitalized for accounting purposes that was deducted in 2004. That amount must be entered on line xx on Sheet XX. Any amount of capitalized interest that is not recoverable from rate payers will be dealt with in the same manner as described in section 7.1.2.8.

7.1.2.18 Property Taxes

The OEB tax filing spreadsheet addresses corporate income tax and capital taxes.

Distributors are also allowed to claim recovery of property taxes payable, including any "proxy" property taxes. Property tax expense is part of the other distribution expenses included in the 2006 EDR Model (see line ***XX*** of that model).

7.1.2.19 Capital Leases

Adjustments for leases that are capitalized for accounting purposes and deducted for tax purposes are made on Sheet xxxx of the 2006 OEB Tax Model.

7.2 Tax Payable Filings

7.2.1 Minimum Information to be Provided with 2006 OEB Tax Model Filings

All applicants must file the following minimum information with respect to taxes in their 2006 rate filings:

- audited financial statements for the years 2002, 2003, and 2004

- taxes actually paid for the years 2002, 2003, and 2004 (estimated) with respect to the distribution business of the applicant

The description of the application must include a description of any variances between taxes actually paid in 2004, and the tax payable sought to be recovered in 2006 distribution rates, where such variances exceed 25% of 2004 taxes actually paid.

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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.

7.2.3 Supporting Documentation

In some instances, disclosure of back-up information or calculations has been mandated, either in the form of a separate Schedule, or at a designated place in the spreadsheet. A complete application must include the supporting information requested in filling instructions.

Where disclosure is not requested as part of the initial filing, applicants should still maintain reasonable supporting documentation in case enquiries are made during the regulatory review process.

Schedule 7-1: Sharing of Tax Exemptions

1.) Sharing Provincial Capital Tax Exemption Within A Corporate Group

As indicated in Section 7.1.2.4 of the 2006 EDR Handbook, if the applicant is a member of a corporate group, the Ontario capital tax exemption must be reasonable and allocated.

Applicants who do not anticipate a significant change in corporate capital mix may use their expected 2004 allocation as a proxy. Where this is not the case, applicants must explain and justify their choice of allocator below.

Distributors for whom the 2004 allocation is not a reasonable proxy: Please provide an explanation and justification of how the Ontario capital tax exemption will be allocated between the applicant and other corporations in the same corporate group, for the purposes of the 2006 OEB PILs model.

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

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.

Schedule 7-2: Sharing Loss Carry-Forwards

1.) Sharing Loss Carry-Forwards between Distribution and Non-Distribution Activities within an Applicant

Where distribution and non-distribution activities are being undertaken within the same legal entity by an applicant, any loss carry-forwards must be allocated on a reasonable basis between the distribution and non-distribution activities.

Please provide a description and justification of the allocation method and calculation.

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Chapter 8

Revenue Requirement

Note: *First draft schedules have been removed from the end of this chapter.*

8.0 Introduction

This chapter provides a bridge between the preceding chapters, which dealt with the cost components included in the revenue requirement for 2006 rates, and the allocation of those costs to customer classes, sub-classes, or groups.

It is the responsibility of the applicant to define its revenue requirement and to record its annual costs and revenues in such a way as to avoid double recovery of any cost element in its rates, regulated charges, and other incidental sources of revenue. This chapter removes from the amounts to be recovered from rate payers through distribution rates, certain amounts that will be collected from regulated charges and other sources of revenue.

8.1 Service Revenue Requirement

The cost elements described in the previous chapters are combined to yield a 2006 service revenue requirement in the following formula:

Service Revenue Requirement = (Rate Base X Cost of Capital) + Distribution Expense + PILS

The 2006 service revenue requirement is based on costs incurred during 2004, plus or minus Tier 1 and Tier 2 adjustments to rate base and distribution expenses.

8.2 Service Revenue Requirement and Base Revenue Requirement

Before the service revenue requirement can be allocated, it is necessary to remove amounts that will be collected from regulated charges and other sources of revenue. The service revenue requirement net of these revenue offsets is the base revenue requirement. The applicant must complete Schedule 8-1 to derive the base revenue requirement. Except where specified otherwise, the cost allocation and rate design in Chapters 9 and 10 achieves the recovery of the base revenue requirement.

Two sources of revenue are to be removed as revenue offsets:

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1. revenue derived from regulated charges applicable to distribution customers (including embedded distributors where applicable) and to retailers

   The amount of the first offset is the sum of the amounts to be reported in Schedules 11-3 and 12-1. The first offset would generally be recorded in USoA Accounts 4225 and 4235, and, if applicable, in Accounts 4080, 4082, and 4084. The charges that determine this revenue offset are the subject of Chapters 11 and 12 below. Host distributors must also include revenue derived from LV charges, found in Schedule 10-8.

2. revenue to the distributor from any source other than regulated rates and charges, such as rental of facilities owned by the distributor, interest on bank accounts, and other incidental sources

   The applicant must report its 2004 revenue from other sources in Schedule 8-1. Generally, this component is calculated as the sum of the amounts in USoA accounts 4205-4415, except for accounts 4225 (late payment charges) and 4235 (Miscellaneous Revenues). If any of these accounts contains revenue from Board-approved rates and charges that is included in Schedule 11-3, the applicant must adjust the amounts in Schedule 8-1 to avoid double-counting of revenues.

Two Tier 1 revenue adjustments may be applicable to the amounts recorded in Schedule 8-1. First, if the applicant is a host distributor, there may be revenue anticipated from embedded distributors in 2006 that differs from the revenue in 2004. The revenue offset to be used is the expected 2005 revenue, and should be included in Row 3. Second, if there were unusual and non-recurring events in 2004 that produced revenue, exceeding a materiality threshold of 2% of total revenue offsets, an adjustment may be made in Schedule 8-1. If the adjustment is in row 2 or row 3, an explanatory note must be included in Schedule 8-1. If the adjustment is in row 4, the corresponding adjustment must be made to the relevant row in Schedule 8-2, with an explanatory note added to Schedule 8-2.

Other adjustments that would affect the revenue a distributor will collect in 2006 are made as load adjustments in Chapter 9. These include gain or loss of a major customer and adjustments for load loss due to CDM programmes.

8.3 CDM, Smart Meter, and Regulatory Asset Amortization Revenue Requirements

The Tier 1 adjustments in Chapter 3 include adjustments to rate base and expenses for CDM and Smart Meter costs. These two components of the revenue requirement, however, may need to be allocated on a different basis from the rest of the base revenue requirement. To allow for this separate allocation, the amounts of these

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components must be identified. The 2006 Handbook will be updated, where necessary, to prescribe the allocation and the calculation of the rate rider for these additional revenue requirement components in Sections 9.3 and/or 10.10.

The applicant must provide the CDM revenue requirement, consisting of CDM programme expenses in 2006, net of those costs that have been retrieved as part of the third tranche of the market-adjusted rate of return in 2005 in…***to be determined***.

The applicant must provide the Smart Meter revenue requirement amount in…***to be determined***.

The costs of regulatory asset amortization will also be allocated on a different basis that the allocation applied to the base revenue requirement. The applicant must provide in Schedule 8-3 information about all regulatory assets that will be amortized (fully or partly) in 2006.

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Schedule 8-1: Derivation of Base Revenue Requirement

No.	Component of Revenue Requirement	2006 Revenue Requirements and Offsets	Comments
1	Service Revenue Requirement		
2	Less: Revenue from Specific Service Charges		Schedule 11-3
3	Less: Revenue from other Board-approved charges		Accounts 4080, 4082, 4084
4	Less: Revenue from sources other than Board-approved rates and charges		Schedule 8-2
5	Base Revenue Requirement		Row 1 – 2 – 3 - 4

Additional comments regarding Schedule 8-1, if necessary.

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Schedule 8-2: Revenue from Sources Other Than Board-Approved Rates and Charges

No.	Description of Revenue	2006 Revenue Offset	Comments
1	Other Operating Revenues		Accounts 4205 – 4245
2	Less: Revenue from Late Payment Charges and Specific Service Charges		Accounts 4225, 4235
3	Net "Other Operating Revenues"		Row 1 – row 2
4	Other Income / Deductions		Accounts 4305 – 4398
5	Investment Income		Accounts 2205 - 4415
6	Total Revenue Offset # 2		Row 3 + 4 + 5

Additional comments regarding Schedule 8-2, if necessary.

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Schedule 8-3: <u>Regulatory Asset Amortization</u>

Regulatory Asset	Balance at April 30, 2006 (including interest)	Amortization in 2006	Allocation Method
Retail Cost Variance Accounts			Customer Count
Miscellaneous Deferred Debits			Distribution Revenue
Transition Costs			Customer Count
Other (please list and explain)			
Total			

Reference: Review and Recovery of Regulatory Assets RP-2003-0064, sections 10.0.12 and 10.0.19)

Additional comments regarding Schedule 8-3, if necessary.

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Chapter 9

Cost Allocation

9.0 Introduction

In the 2001 RUD model, the initial distribution revenue requirement for each rate class, sub-class, or group was established by starting with the total revenue of the class, sub-class, or group collected by the bundled bill, and then subtracting the cost of power allocated to the class, sub-class, or group. Summed over all the rate classes, sub-classes, or groups, the initial total distribution revenue requirement was equal to total revenue less total cost of power.

A cost allocation study is required as a basis for making any significant change to the proportion of total revenue requirement that is assigned to each class, sub-class, or group. The load research results and the cost allocation methodology that are necessary for a cost allocation will not be available for 2006 distribution rate applications.

For 2006, therefore, the respective class distribution revenue requirements should continue at approximately the same proportions of the total distribution revenue requirement, as in the initial design.

9.1 Customer Classes

Distributors will retain the existing rate class definitions in 2006, as outlined in Appendix A, because any proposal to change customer groupings would require support from a cost allocation study.

Currently, distributors may have existing classes, sub-classes, or groups based upon particular circumstances, such as different arrangements or load thresholds, which may or may not have their own group revenue amounts. In this context, for example, the General Service Class is considered a rate class. On the other hand, general service customers <50 kW, scattered unmetered loads, and general service customers >50 kW, would be sub-classes.

If a distributor proposes to make any change to its customer classifications, sub-classes, or groups - that is, if the rate class, sub-class, or group definitions currently in use are not suitable for use in 2006, or if the definitions are to be applied differently in 2006, compared to the current practice - the distributor must complete and file Schedule 9-1, together with a detailed explanation and justification for the proposed change.

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A distributor may have a customer whose maximum billing demand is greater than 50 kW, but who is classified in the <50 kW sub-class, and is therefore billed on kWh. In 2006, the distributor will continue its existing practice with respect to the classification of this customer.

9.2 Determination of the Appropriate Share of the 2006 Revenue Requirement for Each Class, Sub-Class, or Group

In the absence of a cost allocation study, the following methodology has been established to determine the appropriate proportion of the total distribution revenue to be recovered from each class, sub-class, or group.

The methodology uses the 2004 rates minus the recovery of transition costs included in rates prior to 2004, and the recovery of the first phase of the regulatory assets in 2004. These rates are provided on Sheet 2 of the 2004 Rate Adjustment Model (RAM).

The revenues calculated using these rates will be close in proportion to those of the initial class revenue requirements. For most distributors, however, the allocation of the regulatory assets recovery to the respective classes has been done on a different basis.

These rates are then multiplied by the 2004 class customer count (or connection count), times the average of the three years, 2002, 2003, and 2004, kWh/customer and kW/customer data. The resulting dollar amounts for each class, sub-class, or group are then added together to obtain a total dollar amount. The allocation factors that will be used for the 2006 rates will be ratios of each class's, sub-class's, or group's dollar amount to the total.

This method may not produce class proportional allocations that are suitable, in a distributor's opinion, for the 2006 rate process. For example, there may be a fundamental shift in the revenue base, such as the gain or loss of a major industrial customer. As a result, a distributor may consider making adjustments to the allocations.

Each distributor must complete and file Schedule 9-2 as part of its application.

If a distributor proposes to make any change to the methodology or charge determinants, it must complete and file Schedule 9-3, together with a detailed explanation and justification for the proposed change.

A change in the charge determinants is a change in the average load as a result of Tier 1 load adjustments.

1. <u>Gain or loss of a major customer</u>

If the revenue from a major customer that provided a material proportion of distribution revenue in 2004 will not be available in 2006, the amount of the load lost must be taken into account when completing Schedule 9-3. Similarly, if revenue from a major new customer will be gained in a material amount in 2006, the amount of the new load is to be taken into account when completing Schedule 9-3.

2. <u>CDM programme impacts</u>

If the applicant has CDM programmes that are expected to decrease load by a material amount, the load impact on each applicable rate class, sub-class, or group, must be taken into account when completing Schedule 9-3.

3. <u>Smart Meter programme impacts</u>

If the applicant expects any material decrease in billing quantities as a result of its Smart Meter programme, the load impact on the applicable class(es), sub-class(es), or group(s) must be taken into account when completing Schedule 9-3.

These class, sub-class, or group proportions are then applied to the base revenue requirements, as determined in Chapter 8.

There are other costs, identified in Chapters 8 and 10, which require allocation among the classes, sub-classes, or groups. The allocation of these costs may be affected by decisions other than the 2006 EDR Process. They will be addressed separately on an individual basis, and will be consistent with Board decisions.

The resulting amount required from a given class, sub-class, or group used in the determination of the 2006 distribution rates is the sum of the class's, sub-class's, or group's proportional share of the base revenue requirement, plus its allocated share of the other costs.

9.3 Determination of the Appropriate Share of the 2006 CDM, Smart Meter, and Regulatory Asset Revenue Requirements

The 2006 EDR Model requires allocation factors for each of the revenue requirements as input.

The CDM component of revenue requirement will be allocated in the following manner: ***to be determined***

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The Smart Meter component of revenue requirement will be allocated in the following manner: ***to be determined***

In the case of the regulatory asset revenue requirement, the applicant must determine the applicable allocation of each of these revenue requirements from Board decisions. The allocation factors must be calculated from specified allocations of the respective regulatory asset accounts.

If there is no decision available, distribution revenue shares may be used as initial input, as derived in Section 9.2. A revised application may be required if a decision becomes available after an application is filed.

Schedule 9-1: Customer Classification

A distributor must complete this Schedule to indicate that it proposes either to maintain its existing customer classes, sub-classes or groups or to make changes to its customer classes, sub-classes or groups (i.e. if the rate class, sub-class or group definitions currently in use are not suitable for use in 2006 or if the definitions are to be applied differently in 2006 compared to the current practice).

Please indicate the current and proposed customer classifications, as appropriate.

Customer Classification	Current	Proposed
Residential		
Regular	____	____
Time of Use	____	____
Urban	____	____
Suburban	____	____
Other (specify) ______________________	____	____
Other (specify) ______________________	____	____
Other (specify) ______________________	____	____
Other (specify) ______________________	____	____
Other (specify) ______________________	____	____
General Service		
Less than 50 kW	____	____
Less than 50 kW Time of Use	____	____
Other < 50 kW (specify) ________________	____	____
Greater than 50 kW	____	____
Greater than 50 kW Time of Use	____	____
Other > 50 kW (specify) ________________	____	____
Other > 50 kW (specify) ________________	____	____
Other > 50 kW (specify) ________________	____	____
Intermediate Use	____	____
Large Use	____	____
Unmetered Scattered Load	____	____
Sentinel Lighting	____	____
Street Lighting	____	____
Back-up/Standby Power	____	____
Other (specify) ______________________________	____	____
Other (specify) ______________________________	____	____

Please provide a detailed explanation and justification for each of the proposed changes to the classifications.

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Schedule 9-2: Allocation Factors to Customer Classifications

A distributor must fill out this Schedule to provide the 2002, 2003 and 2004 statistical data required to determine the default allocation factors and to indicate acceptance or rejection of the default allocation methodology as outlined in Section 9.2.

Customer Classification	2002 Customers	2002 kWh or kW	2002 per Cust.
Residential			
Regular	________	____________	#VALUE!
Time of Use	________	____________	#VALUE!
Urban	________	____________	#VALUE!
Suburban	________	____________	#VALUE!
Other (specify) ______________________	________	____________	#VALUE!
Other (specify) ______________________	________	____________	#VALUE!
Other (specify) ______________________	________	____________	#VALUE!
Other (specify) ______________________	________	____________	#VALUE!
Other (specify) ______________________	________	____________	#VALUE!
General Service			
Less than 50 kW	________	____________	#VALUE!
Less than 50 kW Time of Use	________	____________	#VALUE!
Other < 50 kW (specify) ______________	________	____________	#VALUE!
Greater than 50 kW	________	____________	#VALUE!
Greater than 50 kW Time of Use	________	____________	#VALUE!
Other > 50 kW (specify) ______________	________	____________	#VALUE!
Other > 50 kW (specify) ______________	________	____________	#VALUE!
Other > 50 kW (specify) ______________	________	____________	#VALUE!
Intermediate Use	________	____________	#VALUE!
Large Use	________	____________	#VALUE!
Unmetered Scattered Load	________	____________	#VALUE!
Sentinel Lighting	________	____________	#VALUE!
Street Lighting	________	____________	#VALUE!
Back-up/Standby Power	________	____________	#VALUE!
Other (specify) ____________________________	________	____________	#VALUE!
Other (specify) ____________________________	________	____________	#VALUE!

Information contained in working group documents reflect the views of those participating in the working groups.
This information does not reflect the Ontario Energy Board's official position or opinion.

Customer Classification	2003 Customers	2003 kWh or kW	2003 per Cust.
Residential			
Regular	________	____________	#VALUE!
Time of Use	________	____________	#VALUE!
Urban	________	____________	#VALUE!
Suburban	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
General Service			
Less than 50 kW	________	____________	#VALUE!
Less than 50 kW Time of Use	________	____________	#VALUE!
Other < 50 kW (specify) ___________________	________	____________	#VALUE!
Greater than 50 kW	________	____________	#VALUE!
Greater than 50 kW Time of Use	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Intermediate Use	________	____________	#VALUE!
Large Use	________	____________	#VALUE!
Unmetered Scattered Load	________	____________	#VALUE!
Sentinel Lighting	________	____________	#VALUE!
Street Lighting	________	____________	#VALUE!
Back-up/Standby Power	________	____________	#VALUE!
Other (specify) ____________________________________	________	____________	#VALUE!
Other (specify) ____________________________________	________	____________	#VALUE!

Information contained in working group documents reflect the views of those participating in the working groups.
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Customer Classification	2004 Customers	2004 kWh or kW	2004 per Cust.
Residential			
Regular	________	____________	#VALUE!
Time of Use	________	____________	#VALUE!
Urban	________	____________	#VALUE!
Suburban	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
Other (specify) __________________________	________	____________	#VALUE!
General Service			
Less than 50 kW	________	____________	#VALUE!
Less than 50 kW Time of Use	________	____________	#VALUE!
Other < 50 kW (specify) ___________________	________	____________	#VALUE!
Greater than 50 kW	________	____________	#VALUE!
Greater than 50 kW Time of Use	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Other > 50 kW (specify) ___________________	________	____________	#VALUE!
Intermediate Use	________	____________	#VALUE!
Large Use	________	____________	#VALUE!
Unmetered Scattered Load	________	____________	#VALUE!
Sentinel Lighting	________	____________	#VALUE!
Street Lighting	________	____________	#VALUE!
Back-up/Standby Power	________	____________	#VALUE!
Other (specify) ____________________________________	________	____________	#VALUE!
Other (specify) ____________________________________	________	____________	#VALUE!

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Customer Classification	2002 - 2004 ave. per Cust.
Residential	
Regular	#VALUE!
Time of Use	#VALUE!
Urban	#VALUE!
Suburban	#VALUE!
Other (specify) ____________________________	#VALUE!
Other (specify) ____________________________	#VALUE!
Other (specify) ____________________________	#VALUE!
Other (specify) ____________________________	#VALUE!
Other (specify) ____________________________	#VALUE!
General Service	
Less than 50 kW	#VALUE!
Less than 50 kW Time of Use	#VALUE!
Other < 50 kW (specify) ____________________	#VALUE!
Greater than 50 kW	#VALUE!
Greater than 50 kW Time of Use	#VALUE!
Other > 50 kW (specify) ____________________	#VALUE!
Other > 50 kW (specify) ____________________	#VALUE!
Other > 50 kW (specify) ____________________	#VALUE!
Intermediate Use	#VALUE!
Large Use	#VALUE!
Unmetered Scattered Load	#VALUE!
Sentinel Lighting	#VALUE!
Street Lighting	#VALUE!
Back-up/Standby Power	#VALUE!
Other (specify) _______________________________________	#VALUE!
Other (specify) _______________________________________	#VALUE!

The default methodology as outlined in Section 9.2 and incorporated in the Model is acceptable.

Yes ____

No ____

If no, the distributor is proposing to make changes to the methodology and/or the statistical data used to derive the per customer data (e.g. as a result of a Tier 1 adjustment) and must complete Schedule 9-3.

Information contained in working group documents reflect the views of those participating in the working groups.
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Schedule 9-3: Non-Default Allocation Factors to Customer Classifications

A distributor must fill out this Schedule if it is proposing to make changes to the default allocation methodology and/or the statistical data used to determine the allocation factors.

If a distributor proposes to use different data than shown in Schedule 9-2, it must provide the data in the following listing, together with a detailed explanation and justification at the end of this Schedule. If a distributor proposes a different methodology, it must provide a detailed explanation and justification at the end of this Schedule and provide the resultant set of data in the following listing.

Customer Classification	Customers	kWh or kW	per Cust.
Residential			
Regular	_______	___________	#VALUE!
Time of Use	_______	___________	#VALUE!
Urban	_______	___________	#VALUE!
Suburban	_______	___________	#VALUE!
Other (specify) __________________________	_______	___________	#VALUE!
Other (specify) __________________________	_______	___________	#VALUE!
Other (specify) __________________________	_______	___________	#VALUE!
Other (specify) __________________________	_______	___________	#VALUE!
Other (specify) __________________________	_______	___________	#VALUE!
General Service			
Less than 50 kW	_______	___________	#VALUE!
Less than 50 kW Time of Use	_______	___________	#VALUE!
Other < 50 kW (specify) ___________________	_______	___________	#VALUE!
Greater than 50 kW	_______	___________	#VALUE!
Greater than 50 kW Time of Use	_______	___________	#VALUE!
Other > 50 kW (specify) ___________________	_______	___________	#VALUE!
Other > 50 kW (specify) ___________________	_______	___________	#VALUE!
Other > 50 kW (specify) ___________________	_______	___________	#VALUE!
Intermediate Use	_______	___________	#VALUE!
Large Use	_______	___________	#VALUE!
Unmetered Scattered Load	_______	___________	#VALUE!
Sentinel Lighting	_______	___________	#VALUE!
Street Lighting	_______	___________	#VALUE!
Back-up/Standby Power	_______	___________	#VALUE!
Other (specify) ____________________________________	_______	___________	#VALUE!
Other (specify) ____________________________________	_______	___________	#VALUE!

The following is the detailed explanation and justification for not using the default allocation factors as determined in Schedule 9-2.

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Chapter 10

Rates and Charges

10.0 Introduction

For the most part, existing methodologies, practices, and procedures are to be maintained for 2006, pending the cost allocation studies that will be available during the 2007 rate process. Deviations from this general approach, if necessary, are identified in the following section.

10.1 Fixed/Variable Split

For each class, sub-class, or group, the rate is composed of two components:

- revenue received through the monthly service charge to the total class distribution revenue

- revenue received through the volumetric rate to the total class distribution revenue (the fixed/variable split) as determined by applying the distribution base rates to the 2004 test year statistics

For each class, sub-class, or group, the ratios of the above revenues will be maintained in the 2006 distribution rates process.

The calculations used in the determination of the fixed/variable split for each class, sub-class, or group are outlined in Sheet_ of the 2006 EDR Model.

The recovery of new adders may be specified in Board decisions. Where not specified by the Board, the distributor will adopt the same splits as for the class (sub-class, or group) revenue requirements.

If an applicant proposes to make any change to the effective fixed/variable split described above (e.g. to mitigate rate impacts), it must complete and file Schedule 10-1, which includes a detailed explanation and justification for the variance from the proposed methodology.

10.2 Unmetered Scattered Loads

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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 <u>either</u> 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.

<u>OR</u>

- 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 at 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 re-allocation of the revenue shortfall as a result of applying this interim measure are 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 as part of its application.

10.3 Time of Use Distribution Rates

A distributor that currently has a legacy time of use rate classification may either retain that classification, or attempt to harmonize it with the equivalent non-time of use classification, at its discretion. Such harmonization would be subject to any constraints resulting from bill impact mitigation.

If the applicant currently has a sub-classification entitled time of use, it must complete and file Schedule 10-3.

10.4 Transformer Ownership Allowance

The current levels of allowance for transformer ownership will be continued for the 2006 rates, and will be explicitly shown on the distributor's rate schedule. An applicant must complete Schedule 10-4 to provide information on this allowance. The 2006 EDR Model will include this allowance in the calculation of the appropriate rates.

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.*

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*

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… 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.

10.7 Standby Charges

Ongoing distribution costs from a customer with load displacement generation facilities behind the meter must be recovered, in order to reflect the need for distribution system facilities as a backup, or in reserve, when the load displacement facilities are not operating.

All applicants will use the following methodology. Each distributor must file Schedule 10-7 to identify its acceptance of the proposed methodology.

Subject to arrangements made between the customer and a distributor with respect to planned outages for maintenance, etc., for every month when the customer does not require the distributor to provide emergency supply (i.e. the load displacement facility has operated), the distributor would apply the regular distribution volumetric rate to an agreed-upon "contracted standby demand" (typically, the name-plate rating of the load displacement facility) in addition to the customer's regular billing demand.

To lessen the possibility of double recovery of distribution costs, when the distributor supplies electricity normally supplied by the load displacement facility, the standby charge would be dropped and the customer would be billed on the metered demand.

The distributor may apply for a monthly administration charge to cover the incremental cost of monitoring, billing, and administration related to providing this service. Such a charge will require a separate cost-justified submission as part of the distributor's Specific Service Charges.

A distributor may wish to propose an alternative to the preceding methodology. For example, after consultation with its customer, it may consider a more detailed direct assignment of costs would be appropriate. If so, the applicant must complete and file the last part of Schedule 10-7 outlining the methodology it proposes, with a detailed explanation and justification for the variance from the proposed methodology. A sample framework is provided in Schedule 10-7.

10.8 Low Voltage Charges

Low voltage charges include the following treatment of charges:

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- recovery of on-going costs from both Hydro One and other distributors

- rates for distributors providing low voltage and related services to other distributors

On-going low voltage charges to distributors by Hydro One and other host distributors will be recovered from the embedded distributor's customers on the same basis as transformation connection charges, and will be allocated to the customer classes on a direct assignment basis.

The rate charged by a host distributor to an embedded distributor will be on the same basis. Host distributors must complete and file Schedule 10-8.

10.9 Demand Determinants

The distributor will continue to establish the billing demands at the greater of 100% of the kW, or 90% of the kVa amounts. A distributor that has established its level of the volumetric demand rates based upon the application of 100% of kVa demand may continue on this basis.

10.10 Recovery of CDM, Smart Meter, and Regulatory Asset Revenue Requirements

The CDM revenue requirement will be recovered by the following method… ***to be determined***

The Smart Meter revenue requirement will be recovered by the following method… ***to be determined***

The regulatory asset amortization revenue requirement will be recovered through a rate rider and allocated to the classes, sub-classes, or groups on the basis of a volumetric change.

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Schedule 10-1: Determination of the Fixed/Variable Splits

The Model will establish the respective fixed/variable splits for each class, sub-class or group using the methodology outlined in the handbook. This Schedule is to be used if the distributor proposes to make any changes to the effective splits. The distributor must provide the data in the following listing, together with a detailed explanation and justification at the end of this Schedule.

Customer Classification	Determined by Model Fixed	Determined by Model Variable	As Proposed Fixed	As Proposed Variable
Residential				
Regular	________	________	________	________
Time of Use	________	________	________	________
Urban	________	________	________	________
Suburban	________	________	________	________
Other (specify) ______________________	________	________	________	________
Other (specify) ______________________	________	________	________	________
Other (specify) ______________________	________	________	________	________
Other (specify) ______________________	________	________	________	________
Other (specify) ______________________	________	________	________	________
General Service				
Less than 50 kW	________	________	________	________
Less than 50 kW Time of Use	________	________	________	________
Other < 50 kW (specify) ______________	________	________	________	________
Greater than 50 kW	________	________	________	________
Greater than 50 kW Time of Use	________	________	________	________
Other > 50 kW (specify) ______________	________	________	________	________
Other > 50 kW (specify) ______________	________	________	________	________
Other > 50 kW (specify) ______________	________	________	________	________
Intermediate Use	________	________	________	________
Large Use	________	________	________	________
Unmetered Scattered Load	________	________	________	________
Sentinel Lighting	________	________	________	________
Street Lighting	________	________	________	________
Back-up/Standby Power	________	________	________	________
Other (specify) ____________________________	________	________	________	________
Other (specify) ____________________________	________	________	________	________

The following is the detailed explanation and justification for not using the fixed/variable splits as determined in the Model.

Schedule 10-2: <u>Unmetered Scattered Loads</u>

A distributor must complete this Schedule regarding unmetered scattered loads.

1) Currently, 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.

Yes ____
No ____

2) Currently, there is an unique level of monthly service charge(s) payable by unmetered scattered loads.

Yes ____
No ____

If the response is yes to either question 1 or 2, the distributor will maintain the status quo in its 2006 rate treatment of unmetered scattered loads, otherwise the distributor will fill in the following table and the rates will be established by the Model, as outlined in point 2 of section 10.2. The Model will also calculate the revenue shortfall and allocate it according to point 3 of section 10.2.

	Customers	kWh
2002 Unmetered Scattered Load	____	________
2003 Unmetered Scattered Load	____	________
2004 Unmetered Scattered Load	____	________
Average Unmetered Scattered Load	____	________

Schedule 10-3: <u>Time of Use Distribution Rates</u>

A distributor that currently has a sub-classification(s) entitled "Time of Use" must complete this Schedule to indicate that it proposes either to maintain the existing methodology to determine a separate set of distribution rates associated with this sub-classification or to harmonize the distribution rates with the equivalent non time of use sub-classification. In choosing the latter option, a distributor may maintain the Time of Use sub-classification for statistical or other purposes.

This distributor currently has a sub-classification(s) entitled "Time of Use".

Yes ____
No ____

This distributor proposes to maintain the existing methodology to determine a separate set of distribution rates associated with the "Time of Use" sub-classification(s).

Yes ____

OR

This distributor proposes to harmonize the distribution rates with the equivalent non time of use sub-classification. In choosing this option the distributor may maintain the "Time of Use" sub-classification for statistical or other purposes.

Yes ____

The following is a detailed explanation and justification of the proposed harmonization methodology, including an implementation plan. In addition, the Impact Analysis part of the Model has been modified to include sufficient bill comparisons to reflect this harmonization.

Schedule 10-4: Transformer Ownership Allowance

A distributor must complete this Schedule regarding transformer ownership allowance. Please provide the 2002, 2003 and 2004 data by sub-class or group as appropriate.

2002	kW	$
General Service		
Greater than 50 kW	________	________
Greater than 50 kW Time of Use	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Intermediate Use	________	________
Large Use	________	________

2003	kW	$
General Service		
Greater than 50 kW	________	________
Greater than 50 kW Time of Use	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Intermediate Use	________	________
Large Use	________	________

2004	kW	$
General Service		
Greater than 50 kW	________	________
Greater than 50 kW Time of Use	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Intermediate Use	________	________
Large Use	________	________

Average	kW	$
General Service		
Greater than 50 kW	________	________
Greater than 50 kW Time of Use	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Other > 50 kW (specify) ____________________	________	________
Intermediate Use	________	________
Large Use	________	________

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Schedule 10-5: Determination of Loss Adjustment Factors

A distributor must complete this Schedule to update the currently approved distribution loss adjustment factors.

Calculation for distribution loss adjustment factors

	2002	2003	2004
(A) "Wholesale" kWh (IMO)	___________	___________	___________
(B) "Wholesale" kWh for Large Use Customer(s) (IMO)	___________	___________	___________
(C) Net "Wholesale" kWh (A)-(B)	___________	___________	___________
(D) "Retail" kWh (Distributor)	___________	___________	___________
(E) "Retail" kWh for Large Use Customer(s) (1% loss)	___________	___________	___________
(F) Net "Retail" kWh (D)-(E)	___________	___________	___________
(G) Loss Factor [(C)/(F)]	___________	___________	___________
(H) Distribution Loss Adjustment Factor (3 year ave.)	___________		

A distributor may propose to use a different loss factor for its large use customer(s) instead of the default 1%, if explained and justified at the end of this Schedule.

If a distributor proposes to use a different distribution loss adjustment factor than as calculated above (H), it must provide a detailed explanation and justification at the end of this Schedule.

The following is the detailed explanation and justification for not using the default large use 1% loss factor and/or for using a different distribution loss adjustment factor than as determined above.

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Schedule 10-6: <u>Distributed Generation</u>

A distributor must complete this Schedule to indicate that it either accepts the methodology outlined in Section 10.6 of the Handbook or proposes a different methodology. If a distributor proposes a different methodology, it must provide a detailed explanation and justification at the end of this Schedule.

The methodology as outlined in Section 10.6 and incorporated in the Model is acceptable.

Yes ____

No ____

Is the distributor applying for a monthly administration charge as part of its Specific Service Charges, as outlined in point 7 of section 10.6?

Yes ____

No ____

If yes, the level of the charge must be cost-justified and submitted as part of the Specific Service Charge section of the application.

If the distributor proposes an alternative methodology, it must be detailed, explained and justified in the following section.

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Schedule 10-7: <u>Standby Charges</u>

A distributor must complete this Schedule to indicate how it proposes to deal with a customer requiring standby power.

The distributor accepts the methodology to apply the appropriate sub-class regular distribution volumetric rate to an agreed-upon contracted standby demand.

Yes ____
No ____

Is the distributor applying for a monthly administration charge as part of its Specific Service Charges, as outlined in section 10.7?

Yes ____
No ____

If yes, the level of the charge must be cost-justified and submitted as part of the Specific Service Charge section of the application.

If the distributor is proposing a different methodology (such as a more detailed direct assignment of costs), it must provide a detailed explanation and justification in the following section of this Schedule. Sheet 2 of this Schedule ("Example") provides a sample methodology.

1	2	3	4	5	6	7	8	9	10	11
						Share of facilities		Share of facilities		
						kW or kVA	kW or kVA	kW or kVA	kW or kVA	percent
Asset Class	Total annual OM&A costs of asset class providing SB services	original cost of asset class providing SB services	Accumulative amortization on asset class providing SB services	Annual amortization on asset class providing SB services	NBV of asset class providing SB services	Total line length or station capacity in asset class	Line length providing SB services	line capacity providing SB services	line capacity or station capacity used to provide SB services	Utilization factor
Primary feeders					$ -					#DIV/0!
Distribution Stations					$ -					#DIV/0!
Low Voltage lines					$ -					#DIV/0!

	12	13	14	15	16
	$	$	$	$	$/kW or $/kVA
Asset Class	return on assets used to provide SB Services	Annual Amortization on assets used to provide SB Services	OM & A cost associated with assets used to provide SB Services	Total annual cost associated with assets used to provide SB Services	Monthly Rate associated with the delivery of SB Services
Primary feeders	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Distribution Stations	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Low Voltage lines	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

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Schedule 10-8: Low Voltage Charges

A host distributor must complete this Schedule to outline its proposed Low Voltage Charges. The following example provides a sample methodology that might be used.

SAMPLE METHODOLOGY
Low Voltage (LV) Charges
Cost tracking and rate based recovery for host distributors.

	percent	
Distributor debt rate(deemed)		deemed debt share
Distributor return on equity before tax (deemed)		deemed equity share
Distributor tax rate		
Distributor return before tax	0.00%	

1	2	3	4	5	6
Asset Class	Total annual OM&A costs of asset class providing LV services	original cost of asset class providing LV services	Accumulative amortization on asset class providing LV services	Annual amortization on asset class providing LV services	NBV of asset class providing LV services
Primary feeders					$ -
Distribution Stations					$ -
Low Voltage lines					$ -

	7	8	9	10	11
	Share of facilities		Share of facilities		
	kW or kVA	kW or kVA	kW or kVA	kW or kVA	percent
Asset Class	Total line length or station capacity in asset class	Line length providing LV services	line capacity providing LV services	line capacity or station capacity used to provide LV services	Utilization factor
Primary feeders					#DIV/0!
Distribution Stations					#DIV/0!
Low Voltage lines					#DIV/0!

	12	13	14	15	16
	$	$	$	$	$/kW or $/kVA
Asset Class	return on assets used to provide LV Services	Annual Amortization on assets used to provide LV Services	OM & A cost associated with assets used to provide LV Services	Total annual cost associated with assets used to provide LV Services	Monthly Rate associated with the delivery of LV Services
Primary feeders	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Distribution Stations	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
Low Voltage lines	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

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Chapter 11

Specific Service Charges

11.0 Introduction

A Specific Service Charge is an approved fixed rate charged to a customer for a specific activity or service, or as a penalty. Activities include services that are only available from, or under the control of, the distributor. There are also special or extra services that a distributor chooses to provide. Such services may be those that are of benefit to the distributor or to other customers, and that are provided at a customer's request or as the result of a customer's action or inaction.

This 2006 Handbook provides a set of well-defined Specific Service Charges that could be provided by a distributor, together with either a specific level of charge or a specific basis for the determination of the charge. All distributors should apply the basic set of services uniformly. There should be no difference in the application of these services among distributors.

Specific Service Charges are established for activities that are over and above the distributor's standard level of service. The Board has outlined what it considers to be a standard level of service for a distributor in the Distribution System Code. The costs of providing the standard level of service are recovered in the regular distribution rates.

Specific Service Charges are an integral part of a distributor's approved schedule of rates for the distribution of electricity. The revenue from these charges is taken into account in calculating a distributor's total revenue requirement. There should be no duplication in the recovery of costs between the Specific Service Charges and the regular distribution rates. Double recovery is to be avoided.

A distributor may determine that a particular Specific Service Charge is not necessary, as it considers the activity to be part of its standard level of service, and the costs are recovered in its regular distribution rates.

The application of a Specific Service Charge may be waived by a distributor provided that the waiver is fairly applied, the practice does not become discriminatory, and it does not provide special terms by way of bonus or otherwise, to the terms at which particular customers are supplied.

A distributor may apply for any unique Specific Service Charge or level of charge. Unique circumstances requiring unique charges or levels require adequate justification by the distributor as part of its application to the Board.

Specific Service Charges can be categorized into five types of charges:

- Customer Administration Charges
- Non-Payment of Account Charges
- Service Call Charges
- Temporary Electricity Service Charges
- Other Services and Charges

Further descriptions of each category are provided in subsequent sections.

For 2006, every applicant must complete and file Schedule 11-1 **(*to be written*)**, outlining the Specific Service Charges it has submitted for approval as part of the rate application.

The applicant may choose one of the following four approaches to define the level of the charge to bill the customer:

- the standard amount, as specified in Schedule 11-1.

- the standard formula, as specified in Schedule 11-2, with adjustments

  If the applicant elects to adjust the level determined by the standard formula, it must provide additional evidence of cost justification for the adjustments.

- the level determined on a basis other than the standard formula

  The applicant must provide evidence to justify the use of a non-standard formula.

- A distributor may specify in its Conditions of Service that the specific service being provided will be charged on an actual cost, time and materials basis, or a pass-through of third party costs. On this basis, approval of the Board is not required, but the applicant must maintain records that demonstrate that the actual cost was charged to the customer.

Other activities undertaken by a distributor could be categorized as contractual arrangements, such as billing for water or sewage for a municipality, or the provision of meter translation/verification services for other distributors. The specifics of such arrangements, including the level of the charge, need not be subject to approval by the

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Board, provided that the applicant submits a statement that identifies all such activities and the revenue received from them The applicant must state in the description of the application that there is no cross-subsidy from ratepayers. The distributor must maintain records that demonstrate that the actual cost was charged to the customer. Revenue from these activities must be included in Schedule 8-1.

11.1 Methodology

The applicant must file Schedule 11-1 to provide a list of the services within each of the identified Charge Codes. An applicant can use Schedule 11-2 to calculate a standard set of specific service charges.

Elements of the calculation for each charge include the following:

- direct labour (internal and/or external)
- labour rate (internal and/or external)
- burden rate
- incidental (e.g. postage for mail)
- vehicle time and rate (if applicable)

The details of each element are found in Schedule 11-2. The specific charge is the sum of these elements.

11.2 Customer Administration

This category's activities or services include those customer requests which are not common to the day-to-day practices as outlined in the distributor's Conditions of Service. Contributing factors used to determine the rate are the length of clerical time and effort required to process the customer's request, and the requirement of a field visit or service call.

There are two standard levels of Customer Administration Charge. One is based upon minor clerical effort (up to 20 minutes in time) with no field visit. The other is based upon more clerical effort (up to 30 minutes in time) and possible a field visit.

Services falling under the first category include the preparation of an arrears certificate, a statement of account/bill copy, or a duplicate invoice for a previous billing.

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Services falling under the second category include account set-up, meter dispute test, and service connection for an installation not covered in the distributor's standard level of service and special meter reads.

11.3 Non-Payment of Account

A distributor's rates include the costs involved in the routine collection of accounts. The rates do not include the activities associated with the non-payment of overdue accounts, as the costs should not be recovered from customers who pay promptly.

The charges that apply to non-payment of account include the following: late payment charge, collection of account service charge, and reconnection of electricity service charge. Any actual pass-through costs, such as bank charges or third party charges, may be added to these charges.

11.3.1 Late Payment Charge

When the total amount of a customer's bill has not been paid within the time outlined by the distributor (which shall be a minimum of sixteen calendar days from the date of mailing or hand delivery of the bill), a late payment charge may be applied to the outstanding balance.

A monthly interest rate of 1.5% (19.56% *per annum*) has been established as the level of this charge for all distributors.

The late payment charge rate and the policy of when it is charged must be disclosed and made available to the customer.

11.3.2 Collection of Account Charge

The collection of account charge is intended to cover the field costs, or part of the costs, of additional collection activities that are beyond the routine of a distributor, as a result of an individual customer's non-payment of its account.

The Distribution System Code defines a disconnect/collect trip as, a visit to a customer's premises by an employee or agent of the distributor to demand payment of any outstanding amount, or to shut off or limit distribution of electricity to the customer failing payment.

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11.3.3 Reconnection of Electricity Service Charge

Pursuant to Section 31 of *The Electricity Act*, and within good management practice, a distributor may consider disconnection of electricity service for non-payment of account. Within its disconnection policy, a distributor may establish a reconnection of electricity service charge. This charge would recover the costs of the physical process of re-establishing power to the customer.

11.4 Service Calls

These are special or extra services to a distributor's standard level of service, and are provided upon a customer's request. The costs of these services can be recovered by billing the actual cost to the customer, or through a Specific Service Charge. When the customer is billed the actual cost of the work, Board approval is not required. If for practical purposes, however, a distributor wishes to use a standard specific charge for its service calls, Board approval is required for the charge. Depending upon the amount of work involved (e.g. amount of field time), the appropriate Charge Code in Schedule 11-1 should be used.

11.5 Temporary Electricity Service Charge

When a customer or its agent requests a temporary service installation, it should pay for the cost of erecting and removing any distributor-owned equipment. A charge may also be made for any transformation equipment supplied by the distributor specifically for this service.

The costs for these services can be recovered by billing the actual cost to the customer, or through a Specific Service Charge. When the customer is billed the actual cost of the work, Board approval is not required. If for practical purposes, however, a distributor wishes to establish a specific charge for the provision of a temporary service, Board approval is required for the charge, which is normally inclusive of some material.

Since at least a component, if not all, of this service could be provided by others, the level of the charge should not be set so as to preclude the ability of another party to provide the service.

11.6 Other Services and Charges

There may be special and/or extra services that a distributor chooses to provide for which it recovers the costs directly from those customers requiring the service, either through an approved service charge, or at actual cost. Some distributors have

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included in their Conditions of Service charges that require Board approval. Board approval of a rate or charge is required unless the rate or charge is one of the following:

i.) a rate or charge for a specific customer based upon the actual costs of the provision of a one time service

ii.) a general customer rate or charge that is a flow-through of third party costs

The other services and charges category also includes services that may be available from providers other than the distributor. For example, a service call for customer-owned equipment for which service can be obtained from private service companies.

11.7 <u>Revenue from Specific Service Charges</u>

The applicant must file Schedule 11-3 to provide a calculation of the revenue to be received from specific service charges in 2006. The resulting revenue calculation will be used in the 2006 EDR Model as a revenue offset.

Revenue from connection charges based upon "time and materials" is to be included as specific service charge revenue, even though they are not Board-approved, in the usual sense.

Schedule 11-1: Specific Service Charges: Standard Amounts

Specific Service Charges - Summary						
Rate Code	Specific Service Charge - Standard Name	Calculation Method - Check box				
		Standard Amount		Standard Formula (attach calculation & justification)	Other Formula (attach calculation & justification)	Time & Materials
1	Arrears certificate	$15				
2	Statement of account	$15				
3	Pulling post dated cheques	$15				
4	Duplicate invoices for previous billing	$15				
5	Request for other billing information	$15				
6	Easement letter	$15				
7	Income tax letter	$15				
8	Notification charge	$15				
9	Account history	$15				
10	Credit reference/credit check (plus credit agency costs)	$15				
11	Returned cheque charge (plus bank charges)	$15				
12	Charge to certify cheque	$15				
13	Legal letter charge	$15				
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$30				
15	Special meter reads	$30				

16	Collection of account charge - no disconnection	$30				
17	Collection of account charge - no disconnection - after regular hours	$165				
18	Disconnect/Reconnect at meter - during regular hours	$65				
19	Install/Remove load control device - during regular hours	$65				
20	Disconnect/Reconnect at meter - after regular hours	$185				
21	Install/Remove load control device - after regular hours	$185				
22	Disconnect/Reconnect at pole - during regular hours	$185				
23	Disconnect/Reconnect at pole - after regular hours	$415				
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30				
25	Service call - customer-owned equipment	$30				
26	Service call - after regular hours	$165				
27	Temporary service install & remove - overhead - no transformer	$500				
28	Temporary service install & remove - underground - no transformer	$300				
29	Temporary service install & remove - overhead - with transformer	$1,000				

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Additional Charges - Please be Specific						
30		N/A				
31		N/A				
32		N/A				
33		N/A				
34		N/A				
35		N/A				
36		N/A				
37		N/A				
38		N/A				
39		N/A				
40		N/A				
41		N/A				

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates							
Specific Service Charge Description:				**$15 Specific Service Charge Calculation**			
Used For:							
	Arrears certificate						
	Statement of account						
	Pulling post dated cheques						
	Duplicate invoices for previous billing						
	Request for other billing information						
	Easement letter						
	Income tax letter						
	Notification charge						
	Account history						
	Credit reference/credit check (plus credit agency costs)						
	Returned cheque charge (plus bank charges)						
	Charge to certify cheque						
	Legal letter charge						
				Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time			23.00	0.4		$9.20
A	Direct Labour (inside staff) Overtime						
B	Direct Labour (field staff) Straight Time			27.00			
O	Direct Labour (field staff) Overtime			27.00			
U	Other Labour (Specify)						
R	Payroll Burden %			30%			$2.76
		Total Labour Cost					$11.96
O	Small Vehicle Time			10.00			
T	Large Vehicle Time			42.00			
H	Other:	Material					
E		Contract					
R		Other		2.00			$2.00
		Total Other					$2.00
Total Cost							$13.96
	Specific Service Charge Value Requested - Round to nearest $5						**$15.00**
Specific Service Charge Description:				**$30 Specific Service Charge Calculation**			
Used For:							
	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)						
	Special meter reads						
	Collection of account charge - no disconnection						
	Meter dispute charge plus Measurement Canada fees (if meter found correct)						
	Service call - customer-owned equipment						

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Specific Service Charge Description:		**$65 Specific Service Charge Calculation**			
Used For:					
	Disconnect/Reconnect at meter - during regular hours				
	Install/Remove load control device - during regular hours				
		Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time	23.00	0.5		$11.50
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	27.00	1		$27.00
O	Direct Labour (field staff) Overtime	27.00			
U	Other Labour (Specify)				
R	Payroll Burden %	30%			$11.55
	Total Labour Cost				$50.05
O	Small Vehicle Time	10.00	1		$10.00
T	Large Vehicle Time	42.00			
H	Other: Material				
E	Contract				
R	Other	3.00			$3.00
	Total Other				$13.00
Total Cost					$63.05
	Specific Service Charge Value Requested - Round to nearest $5				**$65.00**

Specific Service Charge Description:		**$165 Specific Service Charge Calculation**			
Used For:					
	Collection of account charge - no disconnection - after regular hours				
	Service call - after regular hours				
		Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time	23.00	0.6		$13.80
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	27.00			
O	Direct Labour (field staff) Overtime 2hr min	27.00	2	2	$108.00
U	Other Labour (Specify)				
R	Payroll Burden %	30%			$36.54
	Total Labour Cost				$158.34
O	Small Vehicle Time	10.00	0.3		$3.00
T	Large Vehicle Time	42.00			
H	Other: Material				
E	Contract				
R	Other	3.00			$3.00
	Total Other				$6.00
Total Cost					$164.34
	Specific Service Charge Value Requested - Round to nearest $5				**$165.00**

Assumes 1 person - One visit on overtime & minimum 2 hr call out

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Specific Service Charge Description:		$185 Specific Service Charge Calculation			
Used For:					
	Disconnect/Reconnect at meter - after regular hours				
	Install/Remove load control device - after regular hours				
		Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time	23.00	0.5		$11.50
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	27.00	0.5		$13.50
O	Direct Labour (field staff) Overtime 2hr min	27.00	2	2	$108.00
U	Other Labour (Specify)				
R	Payroll Burden %	30%			$39.90
	Total Labour Cost				$172.90
O	Small Vehicle Time	10.00	1		$10.00
T	Large Vehicle Time	42.00			
H	Other: Material				
E	Contract				
R	Other	2.00			$2.00
	Total Other				$12.00
Total Cost					$184.90
	Specific Service Charge Value Requested - Round to nearest $5				**$185.00**
Assumes 1 person - One visit on overtime & minimum 2 hr call out					

Specific Service Charge Description:		$185 Specific Service Charge Calculation- 2 Person Line Crew			
Used For:					
	Disconnect/Reconnect at pole - during regular hours				
		Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time	23.00	0.5		$11.50
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	27.00	3		$81.00
O	Direct Labour (field staff) Overtime 2hr min	27.00		2	
U	Other Labour (Specify)				
R	Payroll Burden %	30%			$27.75
	Total Labour Cost				$120.25
O	Small Vehicle Time	10.00			
T	Large Vehicle Time	42.00	1.5		$63.00
H	Other: Material				
E	Contract				
R	Other	2.00			$2.00
	Total Other				$65.00
Total Cost					$185.25
	Specific Service Charge Value Requested - Round to nearest $5				**$185.00**
Assumes 2 person line crew					

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Specific Service Charge Description:			$415 Specific Service Charge Calculation			
Used For:						
	Disconnect/Reconnect at pole - after regular hours					
			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		23.00	0.5		$11.50
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		27.00	1.5		$40.50
O	Direct Labour (field staff) Overtime 2hr min		27.00	4	2	$216.00
U	Other Labour (Specify)					
R	Payroll Burden %		30%			$80.40
		Total Labour Cost				$348.40
O	Small Vehicle Time		10.00			
T	Large Vehicle Time		42.00	1.5		$63.00
H	Other:	Material				
E		Contract				
R		Other	2.00			$2.00
		Total Other				$65.00
Total Cost						$413.40
	Specific Service Charge Value Requested - Round to nearest $5					**$415.00**
Assumes 2 person line crew - One visit on overtime & minimum 2 hr call out						

Specific Service Charge Description:			$300 Specific Service Charge Calculation			
Used For:						
	Temporary service install & remove - underground - no transformer					
			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		23.00			
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		27.00	5.5		$148.50
O	Direct Labour (field staff) Overtime		27.00			
U	Other Labour (Specify)					
R	Payroll Burden %		30%			$44.55
		Total Labour Cost				$193.05
O	Small Vehicle Time		10.00	1.5		$15.00
T	Large Vehicle Time		42.00	2		$84.00
H	Other:	Material	5.00			$5.00
E		Contract				
R		Other	3.00			$3.00
		Total Other				$107.00
Total Cost						$300.05
	Specific Service Charge Value Requested - Round to nearest $5					**$300.00**
Assumes 1.5 hours for engineering plus 2 people 2 hours each to install/remove						

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Specific Service Charge Description:			$500 Specific Service Charge Calculation			
Used For:						
	Temporary service install & remove - overhead - no transformer					
			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		23.00			
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		27.00	7.5		$202.50
O	Direct Labour (field staff) Overtime		27.00			
U	Other Labour (Specify)					
R	Payroll Burden %		30%			$60.75
		Total Labour Cost				$263.25
O	Small Vehicle Time		10.00	1.5		$15.00
T	Large Vehicle Time		42.00	3		$126.00
H	Other:	Material	95.00			$95.00
E		Contract				
R		Other	3.00			$3.00
		Total Other				$239.00
Total Cost						$502.25
	Specific Service Charge Value Requested - Round to nearest $5					**$500.00**

Assumes 1.5 hours for engineering plus 2 people 3 hours each to install/remove

Specific Service Charge Description:			$1000 Specific Service Charge Calculation			
Used For:						
	Temporary service install & remove - overhead - with transformer					
			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		23.00			
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		27.00	15.5		$418.50
O	Direct Labour (field staff) Overtime		27.00			
U	Other Labour (Specify)					
R	Payroll Burden %		30%			$125.55
		Total Labour Cost				$544.05
O	Small Vehicle Time		10.00	1.5		$15.00
T	Large Vehicle Time		42.00	7		$294.00
H	Other:	Material	145.00			$145.00
E		Contract				
R		Other	3.00			$3.00
		Total Other				$457.00
Total Cost						$1,001.05
	Specific Service Charge Value Requested - Round to nearest $5					**$1,000.00**

Assumes 1.5 hours for engineering plus 2 people 7 hours each to install/remove

Schedule 11-3: Specific Service Charges: Revenue

16	Collection of account charge - no disconnection	$30				#DIV/0!	#DIV/0!
17	Collection of account charge - no disconnection - after regular hours	$165				#DIV/0!	#DIV/0!
18	Disconnect/Reconnect at meter - during regular hours	$65				#DIV/0!	#DIV/0!
19	Install/Remove load control device - during regular hours	$65				#DIV/0!	#DIV/0!
20	Disconnect/Reconnect at meter - after regular hours	$185				#DIV/0!	#DIV/0!
21	Install/Remove load control device - after regular hours	$185				#DIV/0!	#DIV/0!
22	Disconnect/Reconnect at pole - during regular hours	$185				#DIV/0!	#DIV/0!
23	Disconnect/Reconnect at pole - after regular hours	$415				#DIV/0!	#DIV/0!
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30				#DIV/0!	#DIV/0!
25	Service call - customer-owned equipment	$30				#DIV/0!	#DIV/0!
26	Service call - after regular hours	$165				#DIV/0!	#DIV/0!
27	Temporary service install & remove - overhead - no transformer	$500				#DIV/0!	#DIV/0!
28	Temporary service install & remove - underground - no transformer	$300				#DIV/0!	#DIV/0!
29	Temporary service install & remove - overhead - with transformer	$1,000				#DIV/0!	#DIV/0!

Rate Code	Description	Amount	2002 Volume	2003 Volume	2004 Volume	3-Year Average	Revenue
1	Arrears certificate	$15				#DIV/0!	#DIV/0!
2	Statement of account	$15				#DIV/0!	#DIV/0!
3	Pulling post dated cheques	$15				#DIV/0!	#DIV/0!
4	Duplicate invoices for previous billing	$15				#DIV/0!	#DIV/0!
5	Request for other billing information	$15				#DIV/0!	#DIV/0!
6	Easement letter	$15				#DIV/0!	#DIV/0!
7	Income tax letter	$15				#DIV/0!	#DIV/0!
8	Notification charge	$15				#DIV/0!	#DIV/0!
9	Account history	$15				#DIV/0!	#DIV/0!
10	Credit reference/credit check (plus credit agency costs)	$15				#DIV/0!	#DIV/0!
11	Returned cheque charge (plus bank charges)	$15				#DIV/0!	#DIV/0!
12	Charge to certify cheque	$15				#DIV/0!	#DIV/0!
13	Legal letter charge	$15				#DIV/0!	#DIV/0!
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$30				#DIV/0!	#DIV/0!
15	Special meter reads	$30				#DIV/0!	#DIV/0!

Additional Charges - Please be Specific							
30						#DIV/0!	#DIV/0!
31						#DIV/0!	#DIV/0!
32						#DIV/0!	#DIV/0!
33						#DIV/0!	#DIV/0!
34						#DIV/0!	#DIV/0!
35						#DIV/0!	#DIV/0!
36						#DIV/0!	#DIV/0!
37						#DIV/0!	#DIV/0!
38						#DIV/0!	#DIV/0!
39						#DIV/0!	#DIV/0!
40						#DIV/0!	#DIV/0!
41						#DIV/0!	#DIV/0!
					Total SSC Revenue		#DIV/0!
	Revenue from Late Payment Charges					#DIV/0!	

Total SSC Revenue	#DIV/0!
Revenue from Late Payment Charges	#DIV/0!
Total	#DIV/0!

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Schedule 11-3: Specific Service Charges: Revenue

Rate Code	Description	Amount	2002 Volume	2003 Volume	2004 Volume	3-Year Average	Revenue
1	Arrears certificate	$15				#DIV/0!	#DIV/0!
2	Statement of account	$15				#DIV/0!	#DIV/0!
3	Pulling post dated cheques	$15				#DIV/0!	#DIV/0!
4	Duplicate invoices for previous billing	$15				#DIV/0!	#DIV/0!
5	Request for other billing information	$15				#DIV/0!	#DIV/0!
6	Easement letter	$15				#DIV/0!	#DIV/0!
7	Income tax letter	$15				#DIV/0!	#DIV/0!
8	Notification charge	$15				#DIV/0!	#DIV/0!
9	Account history	$15				#DIV/0!	#DIV/0!
10	Credit reference/credit check (plus credit agency costs)	$15				#DIV/0!	#DIV/0!
11	Returned cheque charge (plus bank charges)	$15				#DIV/0!	#DIV/0!
12	Charge to certify cheque	$15				#DIV/0!	#DIV/0!
13	Legal letter charge	$15				#DIV/0!	#DIV/0!
14	Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$30				#DIV/0!	#DIV/0!
15	Special meter reads	$30				#DIV/0!	#DIV/0!
16	Collection of account charge - no disconnection	$30				#DIV/0!	#DIV/0!
17	Collection of account charge - no disconnection - after regular hours	$165				#DIV/0!	#DIV/0!
18	Disconnect/Reconnect at meter - during regular hours	$65				#DIV/0!	#DIV/0!
19	Install/Remove load control device - during regular hours	$65				#DIV/0!	#DIV/0!
20	Disconnect/Reconnect at meter - after regular hours	$185				#DIV/0!	#DIV/0!
21	Install/Remove load control device - after regular hours	$185				#DIV/0!	#DIV/0!

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22	Disconnect/Reconnect at pole - during regular hours	$185				#DIV/0!	#DIV/0!
23	Disconnect/Reconnect at pole - after regular hours	$415				#DIV/0!	#DIV/0!
24	Meter dispute charge plus Measurement Canada fees (if meter found correct)	$30				#DIV/0!	#DIV/0!
25	Service call - customer-owned equipment	$30				#DIV/0!	#DIV/0!
26	Service call - after regular hours	$165				#DIV/0!	#DIV/0!
27	Temporary service install & remove - overhead - no transformer	$500				#DIV/0!	#DIV/0!
28	Temporary service install & remove - underground - no transformer	$300				#DIV/0!	#DIV/0!
29	Temporary service install & remove - overhead - with transformer	$1,000				#DIV/0!	#DIV/0!
Additional Charges - Please be Specific							
30						#DIV/0!	#DIV/0!
31						#DIV/0!	#DIV/0!
32						#DIV/0!	#DIV/0!
33						#DIV/0!	#DIV/0!
34						#DIV/0!	#DIV/0!
35						#DIV/0!	#DIV/0!
36						#DIV/0!	#DIV/0!
37						#DIV/0!	#DIV/0!
38						#DIV/0!	#DIV/0!
39						#DIV/0!	#DIV/0!
40						#DIV/0!	#DIV/0!
41						#DIV/0!	#DIV/0!
						Total SSC Revenue	#DIV/0!

Total SSC Revenue	#DIV/0!

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Revenue from Late Payment Charges	
Total	#DIV/0!

Chapter 12

Other Regulated Charges

12.0 <u>Introduction</u>

This chapter provides guidance to distributors with respect to the charges related to the administration of the Standard Supply Service (SSS) (to be renamed the Regulated Price Plan (RPP)), Retail Service Charges, and Non-competitive Electricity Charges.

These charges are exclusive of the distribution monthly service charges, volumetric rates, and specific service charges covered in previous chapters.

For 2006, the levels of these charges will be maintained at their existing levels.

12.1 <u>SSS (to be re-named RPP) Administration Charge</u>

A standard charge of $0.25 per month, per customer.

12.2 <u>Retail Service Charges</u>

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

12.2.1 Establishing Service Agreements

Charges to a retailer:

- standard charge (one-time charge) of $100 per agreement, per retailer (intended to recover the costs of entering into the service agreement required by the RSC)
- monthly fixed charge of $20 per month, per retailer (intended to recover the cost of contract administration and monitoring prudential requirements)
- monthly variable charge of $0.50 per month, per customer (intended to recover costs related to general accounting, administration services, and other communication and customer care services necessary to maintain the contract)

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12.2.2 Distributor-Consolidated Billing

A standard distributor-consolidated billing charge of $0.30 per month, per customer, will be collected from the retailer (intended to recover the incremental costs incurred by a distributor in providing a distributor-consolidated, bill-ready service).

The charge for rate-ready billing will be determined based upon the incremental cost to the distributor to provide the service. A distributor must apply to the Board to establish the charge. If the Board has approved such a charge for a distributor, it is to be maintained at its current amount for 2006.

12.2.3 Retailer-Consolidated Billing

Under this arrangement, a distributor does not directly bill a customer. An avoided cost credit of $0.30 per month, per customer will be paid to a retailer that chooses retailer-consolidated billing.

12.2.4 Service Transaction Requests (STR)

An STR is specific to an individual customer. Each fee will be charged on a per customer basis. These fees are intended to recover the incremental cost of labour, internal information system maintenance costs, and delivery costs.

- request fee of $0.25 per request (intended to recover costs incurred by a distributor for the initial screening process of a STR) regardless of whether or not the STR can be processed

  request fee is applied to the requesting party

- processing fee of $0.50 per request (intended to recover the costs incurred to process the transaction based upon rules and procedures set out under Chapter 10 of the RSC) applied to the requesting party if the request is processed

  processing fee is applicable to the following services:

  - a change in electricity supply for a customer from SSS to a retailer
  - a change in electricity supply for a customer from one retailer to another
  - a change in electricity supply for a customer from a retailer to SSS
  - a change in a customer’s metering or billing options for customers currently served by a retailer

- a change in customer location

Fee for specific STRs

A retailer or customer may request customer information as outlined in Section 10.6.3 and in Chapter 11 of the RSC. A request to deliver data directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, will be honoured twice a year at no direct charge to retailer or customer.

Where requests exceed two per year, an information delivery charge of $2 per request, plus any incremental delivery costs, may be charged where a request is considered to be data delivered to a single address.

Default

Under Section 8.4 of the RSC, in the event of settlement payment default by a retailer, if the account remains unpaid after 10 business days from the date the settlement payment was due, and the parties have not agreed upon a remedy, the distributor may notify the retailer's customers that they will become SSS customers.

For the purposes of the 2006 Handbook, a distributor may treat this transfer as an STR requested by the retailer, and may recover the request and processing fee from the retailer.

Other associated costs

If a distributor provides an associated service (e.g. special meter reading) to facilitate the process of an STR, it may recover the applicable associated costs at the level specified in its rate schedule.

If the Board has approved such a charge for a distributor, it is to be maintained for 2006. If no rate is in place, the distributor may apply to the Board for a specific rate.

12.2.5 Monitoring and Cost Tracking

Distributors should establish or maintain the appropriate Retail Services Costs Variance Accounts (RCVA) to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

Details of the RCVA are set out in Account 490 of the Board's Accounting Procedures Handbook.

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12.3 Non-Competitive Electricity Charges

This section provides a listing of the standard charges for non-competitive services. In all cases, the current Board-approved rates and charges are to be maintained for 2006.

12.3.1 Wholesale Market Service Rate

The rate of $0.0052/kWh applies to those customers of a distributor who are not wholesale market participants.

An embedded distributor who is not a wholesale market participant shall be treated as a customer to the host distributor and will be charged the same rate.

The Wholesale Market Service Rate shall be applied to the customer's metered consumption, adjusted by the distributor's total loss factor.

12.3.2 Retail Transmission Service Rates

There are two separate rates: the retail transmission network service rate, and the retail transmission connection service rate.

The existing rates will be maintained for 2006, and will apply to customers in each existing distribution customer class.

12.3.3 Charges/Taxes Levied by the Government of Ontario

While these charges/taxes are part of a customer's bill, the levels of these charges are not approved by the Board, and they will therefore not be part of the distributor's rate schedule or rate order.

Rural and Remote Rate Protection (RRRP) of $0.001/kWh.

Debt Retirement Charge of $0.007/kWh (or less, depending upon the percentage of a distributor's load supplied by the former Ontario Hydro).

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Chapter 13

Mitigation

13.0 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).

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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.

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.*

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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.

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?)*

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Chapter 15

Service Quality Regulation

15.0 Introduction

This chapter provides the definitions and reporting requirements of distribution service quality indicators, and the minimum standards set for the service quality indicators. In accordance with Section 2.1.4 of the Board's Reporting and Record-keeping Requirements, utilities are required to report, by January 31, their service quality and reliability performance for the previous calendar year. An applicant must file its service quality indicators as part of its rate application in 2006, in Schedule 15-1.

The service quality indicators, their associated monitoring and reporting requirements, and the minimum standards (where applicable) are described below. These standards represent the minimum acceptable performance levels. An electricity distribution utility should continue to establish its operating performance at levels better than the minimum standards, taking into consideration the needs and expectations of their customers.

Table 15.1
Service Quality Indicators

Customer Service	Service Reliability
Connection of new services Underground cable locates Appointments Telephone accessibility Written response to enquiries Emergency response	System average interruption duration index System average interruption frequency index Customer average interruption duration index

In the absence of consistent historical service quality data, it was not possible to identify service degradation during first generation PBR. The Board has initiated an SQR review (RP-2003-0190) that may determine thresholds for service quality and service degradation.

15.1 Customer Service Performance Indicators

A customer service indicator measures direct contact with the customer. In setting the customer service standards, minimum standard guidelines are provided that are

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intended to maintain customer service quality, while providing the utilities with flexibility to set service levels to the demands of their customers above the minimum guidelines. The electricity distribution utilities are expected to achieve the minimum standards for a specified percentage of the time.

15.1.1 Connection of New Services

The connection of new services indicator measures the percentage of requests that are met within the required minimum performance standard.
As a minimum performance standard for the connection of new universal services, new low voltage (<750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time. New high voltage (>750 volts) service must be connected within 10 working days from the day on which all conditions of service are satisfied, including electrical safety inspection, at least 90% of the time.

The conditions of service that may need to be satisfied include the following:

- payment of connection fees
- signing of service contracts,
- completion of distribution system extensions
- provision of adequate lead times for delivery of equipment
- receipt of an electrical safety inspection certificate

The utility must monitor its performance monthly and report the information annually to the Board. The monthly information is to be reported as follows:

(1) number of new low voltage services connected

(2) number of new low voltage service connected within 5 working days

(3) percentage of requests for new low voltage service met within 5 working days [((2*100)/(1)]

(4) number of new high voltage service connected

(5) number of new high voltage service connected within 10 working days

(6) percentage of requests for new high voltage service met within 10 working days [((5*100)/(4)]

15.1.2 Underground Cable Locates

The underground cable locates indicator measures the percentage of requests for cable locates that are completed within the minimum performance standard.

As a minimum standard, underground cable locates must be completed within 5 working days of a customer's request, at least 90% of the time. For customers requesting a specific date, the locate must be completed within 5 working days of the requested date. The cable locates included in this standard do not include emergency locates.

The utility must monitor its performance monthly and report the information annually.

The monthly information is to be reported as follows:

(1) number of cable locates requested

(2) number of cable locates performed within 5 working days

(3) percentage of requests met within 5 working days [((2*100)/(1)]

15.1.3 Telephone Accessibility

The telephone accessibility indicator measures the percentage of incoming calls to the general enquiry telephone number answered within the minimum of the performance standard.

As a minimum standard, incoming calls to the general enquiry telephone number must be answered in person by an operator within 30 seconds, at least 65% of the time. The provision of a voice mailbox or answering machine does not constitute compliance with this measure.

The utility must monitor its performance monthly and report the information annually.

The monthly information is to be reported as follows:

(1) number of general enquiry telephone calls answered

(2) number of general enquiry telephone calls answered within 30 seconds

(3) percentage of general enquiry telephone calls answered within 30 seconds [((2*100)/(1)]

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15.1.4 Appointments Met

The appointments indicator measures the percentage of appointments at a customer's premises or work site that are met at the appointed time within the minimum performance standard.

As a minimum standard, when it is necessary to meet a customer at the customer's premises or work site to conduct utility business, customers must be offered a choice of morning or afternoon appointments. The appointments must be met at the appointed time, at least 90% of the time.
Outside of the minimum standard established for this index, if the appointed time cannot be met, the utility must notify the customer.

The utility must monitor its performance monthly and report the information annually.

The monthly information is to be reported as follows:

(1) number of appointments at a customer's premises or work site made

(2) number of appointments at a customer's premises or work site kept at the appointed time

(3) percentage of appointments at a customer's premises or work site made within minimum standard [((2*100)/(1)]

15.1.5 Written Responses to Enquiries

The written response to enquiries indicator measures the percentage of responses to enquiries that require written responses that are made within the minimum performance standard.

The minimum standard for responding to requests by a customer or an agent of the customer for written information relating to the customer's account, will be within 10 working days following receipt of the request. The written response time must be met at least 80% of the time.

The utility must monitor its performance monthly and report the information annually.

The monthly information is to be reported as follows:

(1) number of requests for written responses

(2) number of requests for written responses provided within 10 working days

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(3) percentage of requests for written responses met within minimum standard [((2)*100/(1)]

15.1.6 Emergency Response

The emergency response indicator measures the percentage of emergency responses that are made within the minimum performance standard.

At a minimum, emergency trouble calls (e.g. fire, ambulance, police) will be responded to within 120 minutes in rural areas, and within 60 minutes in urban areas. The definition of rural and urban should follow the municipality's definition. The arrival of a qualified service person on site will constitute the response. The minimum standards must each be met at least 80% of the time.

The utility must monitor its performance monthly and report the information annually.

The monthly information is to be reported as follows:

(1) number of emergency calls for rural customers

(2) number of emergency calls for rural customers at which qualified staff were on site within 120 minutes

(3) percentage of emergency calls for rural customers met within 120 minutes [((2*100)/(1)]

(4) number of emergency calls for urban customers

(5) number of emergency calls for urban customers at which qualified staff were on site within 60 minutes

(6) percentage of emergency calls for urban customers met within 60 minutes [((5*100)/(4)]

15.2 <u>Service Reliability Indices</u>

Service reliability indices measure system outage statistics. The monitoring and reporting of service reliability indices are intended to encourage utilities to maintain or exceed their existing service reliability performance.

15.2.1 System Average Interruption Index (SAIDI)

The SAIDI is an indicator of system reliability that expresses the length of outage customers experience in the year on average. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Served}}$$

All utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past are required to start monitoring and reporting on this index when they start their first PBR plan.
Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

The monthly information is to be reported as follows:

(1) total customer-hours of interruptions

(2) total number of customers served

(3) SAIDI [(1)/(2)]

15.2.2 System Frequency Interruption Index (SAIFI)

The SAIFI is an indicator of the average number of interruptions each customer experiences. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as, the number of interruptions normalized per customer served, and it is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

All utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past are required to start monitoring and reporting on this index.

Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

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The monthly information is to be reported as follows:

(1) total number of customer interruptions

(2) total number of customers served

(3) SAIFI [(1)/(2)]

15.2.3 Customer Average Interruption Index (CAIDI)

The CAIDI is an indication of the speed at which power is restored. All planned and unplanned interruptions of one minute or more should be used to calculate this index. It is defined as, the average duration of interruptions in the year, and it is expressed as follows:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customer Interruptions}}$$

All utilities are required to monitor this index monthly and to report to the Board on an annual basis. Utilities that have not monitored this index in the past are required to start monitoring and reporting on this index.

Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.

The monthly information is to be reported as follows:

(1) total customer hours of interruptions (SAIDI)

(2) total number of customer interruptions (SAIFI)

(3) CAIDI [(1)/(2)]

15.3 <u>Cause of Service Interruption</u>

Monitoring the cause of outages, in addition to monitoring the system reliability indices, provides valuable information as to the remedial work required. The electricity distribution utilities should therefore maintain a record of the causes of the outages, at a minimum, in accordance with the list presented in Table 15.2.

While annual reporting of this information to the Board is not mandatory, the Board will expect the utility to produce this information, should a review of the utility's service reliability be necessary.

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The following cause codes have been updated to correspond with the Canadian Electrical Association's codes.

Table 15.2 Cause of Service Interruption	
Code	**Cause**
0	**Unknown/Other** customer interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage** customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	**Loss of Supply** customer interruptions due to problems in the bulk electricity supply system
3	**Tree Contacts** customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	**Adverse Environment** customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing (previously Code 9)
8	**Human Element** customer interruptions due to the interface of utility staff with the system (previously Code 7)
9	**Foreign Interference** customer interruptions beyond the control of the utility, such as animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects (previously Code 8)

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Schedule 15-1: Service Quality and Reliability Performance 2002 to 2004

Actual Schedule will be done in Excel

Service Quality and Reliability Performance

A utility is required to provide its summary annual performance for the years 2002 to 2004 inclusive, on service quality and reliability indicators. These statistics are the same as the annual statistics from a utility's RRR section 2.1.4 filing for each report year. Where there have been changes in a utility's structure, due to a merger, acquisition, or divestiture, the utility is requested to provide its performance according to its actual structure. This may require the utility to report the information on a separate schedule.

Service Quality Indicators

1a.	Connection of New Services – Low Voltage		
	Standard: 90% or better		
	2002	2003	2004
1b	Connection of New Services – High Voltage		
	Standard: 90% or better		
	2002	2003	2004
2	Underground Cable Locates		
	Standard: 90% or better		
	2002	2003	2004
3	Appointments Met		
	Standard: 90% or better		
	2002	2003	2004

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4	Telephone Accessibility (Telephone Service Factor)		
	Standard: 65% or better		
	2002	2003	2004
5	Written Responses to Enquiries		
	Standard: 80% or better		
	2002	2003	2004
6a	Emergency Response - Urban		
	Standard: 80% or better		
	2002	2003	2004
6b	Emergency Response - Rural		
	Standard: 80% or better		
	2002	2003	2004

Reliability Indicators

7	SAIDI (System Average Interruption Duration Index)		
	Standard: Within the range of performance over the previous 3 years		
	2002	2003	2004
8	SAIFI (System Average Interruption Frequency Index)		
	Standard: Within the range of performance over the previous 3 years		
	2002	2003	2004
9	CAIDI (Customer Average Interruption Duration Index)		
	Standard: Within the range of performance over the previous 3 years		

	2002	2003	2004

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Appendix B: Rate Base Accounts

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

Definition of Distribution Activities

The distribution activities identified below, along with the associated assets, will be considered to be distribution activities and assets for the purposes of the rate base calculation.

Distribution activities are those that enable the conveyance of electricity for distribution purposes.

Assets associated with activities that enable such conveyance will be considered to be distribution assets.

The following activities are generally considered to be distribution activities:

- operation and management of the distribution system
- meter reading services, including verification, testing, approval, and installation and removal services
- billing and collection services
- line clearing services
- repair and maintenance for distribution lines and facilities
- planning, design, and construction of distribution lines and facilities, including system planning and load forecasting services
- general administrative support services, including corporate services such as management, payroll, regulatory compliance service, etc.
- telecommunications services for electricity distribution (e.g. SCADA)
- energy efficiency services that are approved by the Board, including Conservation and Demand Management programmes
- customer care services, including call centre services

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- energy education services
- services required under other Board codes or guidelines
- other service(s) that satisfy the above definition

The following activities are not considered to be distribution activities. Assets associated with such activities will be considered to be non-utility assets.

- street lighting services
- renting or selling of hot water heaters
- renting of sentinel lights
- water and sewer services
- electricity generation
- electricity transmission
- other services that do not satisfy the above definition

To determine its regulated rate base, the applicant should have developed an allocation policy separately to account for costs related to distribution activities and assets from those that are non-utility-related. This will help to ensure that there is no cross-subsidization between the regulated and the non-regulated lines of business within the utility.

The method of separating the costs of activities and assets should be calculated in accordance with a reasonable method of determining a fair and equitable separation that would best reflect the "used and useful" principle and the Separation of Costs Method, below. The allocation method should be documented, and the documentation should be available for Board review.

"Used and Useful" Principle

The utility should follow the "used and useful" principle in developing its policies and procedures for allocating costs. Under this principle, the portion of joint activities or assets that are used and useful in the distribution of electricity should be allocated to distribution activities and assets.

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Separation of Costs Method

The amounts removed from the integrated rate base, actual or notional, should be based upon net book value.

Definition of Rate Base

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.

The following tables are to be used to calculate the rate base for the regulated distribution activities. Consequently, the following two tables must be completed and submitted as part of the rate application filings.

Table B.1: Listing of Distribution Asset Accounts

This table lists the distribution "distribution" asset accounts to be included in the rate base calculation.

Table B.2: Listing of Distribution "Distribution" Accounts Related to the Working Capital Calculation

This table lists the distribution accounts, related to the working capital calculation, to be included in the rate base in accordance with the guidelines provided earlier in this appendix.

It is the responsibility of the utility to ensure the completeness and accuracy of the information submitted to the Board.

Financial Parameters Working Group Suggested Modification

The Financial Parameters sub-group has proposed that the cost of power account include all series 4700 accounts, resulting in the addition of, specifically, 4708, 4712, 4716, and 4720.

These accounts have been incorporated into the following tables. They were added to the APH in the December 2001 update, which would have post-dated the previous edition of the Rate Handbook.

Please comment on any concerns with this proposed change.

Calculation of Net Fixed Assets, Distribution Assets

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 accounts contain assets that are considered to be essential to enabling the conveyance of electricity. For the purpose of this calculation, any asset that is used for both distribution and for non-utility purposes must be prorated between the uses, and only the applicable portion related to distribution should be included here. The method of allocation should be reasonable and documented. The documentation should be available for Board review.

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Table B.1 Listing of Distribution distribution Asset Accounts		
Account Number	**Detailed Asset Accounts (other than Construction Work in Progress)**	**Year-End Amount**
	A. Intangible Plant	
1608	Franchises and consents	
	D. Distribution Plant	
1805	Land	
1806	Land rights	
1808	Buildings and fixtures	
1810	Leasehold improvements	
1820	Distribution station equipment – normally primary below 50 kV	
1825	Storage battery equipment	
1830	Poles, towers, and fixtures	
1835	Overhead conductors and devices	
1840	**Underground conduit**	
1845	Underground conductors and devices	
1850	Line transformers	
1855	Services	
1860	Meters	
	E. General Plant	
1905	Land	
1906	Land rights	
1908	Buildings and fixtures	
1910	Leasehold improvements	
1915	Office furniture	
1920	Computer equipment: hardware	
1925	Computer software	

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Table B.1 Listing of Distribution distribution Asset Accounts		
Account Number	**Detailed Asset Accounts (other than Construction Work in Progress)**	**Year-End Amount**
1930	Transportation equipment	
1935	Stores equipment	
1940	Tools, shop, and garage equipment	
1945	Measurement and testing equipment	
1950	Power-operated equipment	
1955	Communication equipment	
1960	Miscellaneous equipment	
1970	Load management controls: customer premises	
1975	Load management controls: utility premises	
1980	System supervisory equipment	
1990	Other tangible property	
1995	Contributions and grants: credit	
Other Capital Assets		
2005	Property under capital leases	
2010	Electric plant purchased or sold	
2050	Completed construction not classified: electric	
205**X**	**Other amounts not listed above – please provide details**	
Total (A) (Total of Accounts 1601 to 205X above)		

Table B.1 Listing of Distribution distribution Asset Accounts		
Account Number	**Detailed Asset Accounts (other than Construction Work in Progress)**	**Year-End Amount**
	Accumulated Amortization	
2105	Accumulated Amortization of Electric Utility Plant – Property, Plant, and Equipment (distribution-related expenses only)	
2120	Accumulated Amortization of Electric Utility Plant – Intangibles Equipment (distribution-related expenses only)	
212**X**	**Other amounts not listed above – please provide details**	
	Total (B) (Total of Accounts 2105 to 212X above)	
	Total net fixed assets (Total A – Total B)	
	Working Capital Allowance (From Table B.4)	
	Total Rate Base	

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The following table, provided for the benefit of the applicant, lists assets that are generally **not** considered necessary for the conveyance of electricity for rate-making purposes, and consequently need not be considered to be distribution-related assets.

Any asset listed below that is used for both distribution and non-utility purposes must be prorated between the uses, and the portion related to distribution should be included in Table B.1 under "Other amounts not listed above." The method of allocation should be reasonable and documented.

Non-Utility Assets / Assets Not Part of Rate Base Calculation	
Account	**Account Name**
1606	Organization
1610	Miscellaneous intangible plant
1615	Land
1616	Land rights
1620	Buildings and fixtures
1630	Leasehold improvements
1635	Boiler plant equipment
1640	Engines and engine-driven generators
1645	Turbo-generator units
1650	Reservoirs, dams, and waterways
1655	Water wheels, turbines, and generators
1660	Roads, railroads, and bridges
1665	Fuel holders, producers, and accessories
1670	Prime movers
1675	Generators
1680	Accessory electric equipment
1685	Miscellaneous power plant equipment
1705	Land
1706	Land rights
1708	Buildings and fixtures

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Non-Utility Assets / Assets Not Part of Rate Base Calculation	
Account	**Account Name**
1710	Leasehold improvements
1715	Station equipment
1720	Towers and fixtures
1725	Poles and fixtures
1730	Overhead conductors and devices
1735	Underground conduit
1740	Underground conductors and devices
1745	Roads and trails
1815	Transformer station equipment – normally primary above 50kV
1865	Other installations on customer premises
1870	Leased property on customer premises
1875	Street lighting and signal systems
1965	Water heater rental units
1985	Sentinel lighting rental units
2020	Experimental electric plant unclassified
2030	Electric plant and equipment leased to others
2040	Electric plant held for future use
2055	Construction work in progress: electric
2060	Electric plant acquisition adjustment
2065	Other electric plant adjustment
2070	Other utility plant
2075	Non-utility property owned or under capital leases
2105	Accumulated Amortization of Electric Utility Plant – Property, Plant, and Equipment (non-utility-related assets only)
2120	Accumulated Amortization of Electric Utility Plant – Intangibles Equipment (non-utility-related assets only)
2140	Accumulated Amortization of Electric Plant Acquisition Adjustment
2160	Accumulated Amortization of Other Utility Plant

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Non-Utility Assets / Assets Not Part of Rate Base Calculation	
Account	**Account Name**
2180	Accumulated Amortization of Non-Utility Property

Working Capital Allowance Calculation, Distribution distribution Accounts

The total amounts in the following accounts (as applicable) will be used to calculate the working capital allowance.

Table B.2 Listing of Distribution distribution Accounts Related to the Working Capital Calculation		
Account Number	**Account Name**	**Year-End Amount**
Other Power Supply Expenses		
4705	Power purchased	
4708	***Charges: WMS***	
4710	Cost of power adjustments	
4712	***Charges: one-time***	
4714	***Charges: NW***	
4715	System control and load displacing	
4716	***Charges: CN***	
4720	***Other Expenses***	
4725	Competition transition expenses	
4730	Rural rate assistance expense	
Distribution Expenses – Operation		
5005	Operation supervision and engineering	
5010	Load displacing	
5012	Distribution station equipment: operation labour	
5017	Distribution station equipment: operation supplies and expenses	
5020	Overhead distribution lines and feeders	
5025	Overhead distribution lines and feeder: operation supplies	
5030	Overhead sub-transmission feeders: operation (related to lines under 50 kV)	
5035	Overhead distribution transformers: operation	

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Table B.2 Listing of Distribution distribution Accounts Related to the Working Capital Calculation		
Account Number	**Account Name**	**Year-End Amount**
5040	Underground distribution lines and feeders	
5045	Underground distribution lines and feeders: supplies and operation	
5050	Underground sub-transmission feeders: operation (related to lines under 50kV)	
5055	Underground distribution transformers: operation	
5065	Meter expense	
5070	Customer premises: operation labour	
5075	Customer premises: materials and expenses	
5085	Miscellaneous distribution expense	
5090	Underground distribution lines and feeders: rental paid	
5095	Overhead distribution lines and feeder: rental paid	
5096	Other rent	
Distribution Expenses – Maintenance		
5105	Maintenance supervision and engineering	
5110	Maintenance of structures	
5114	Maintenance of distribution station equipment	
5120	Maintenance of poles, towers, and fixtures (related to lines under 50 kV)	
5125	Maintenance of overhead conductors and devices (related to lines under 50 kV)	
5130	Maintenance of overhead services	
5135	Overhead distribution lines and feeders: right of way	
5145	Maintenance of underground conduit (related to lines under 50 kV)	
5150	Maintenance of underground conductors and devices (related to lines under 50kV)	
5155	Maintenance of underground services	
5160	Maintenance of line transformers	

Table B.2 Listing of Distribution distribution Accounts Related to the Working Capital Calculation		
Account Number	**Account Name**	**Year-End Amount**
5175	Maintenance of meters	
Other Expenses		
5205	Purchase of transmission and system services	
5210	Transmission charges	
5215	Transmission charges recovered	
Billing and Collecting		
5305	Supervision	
5310	Meter reading expense	
5315	Customer billing	
5320	Collecting	
5325	Collecting: cash over and short	
5330	Collection charges	
5335	Bad debt expense	
5340	Miscellaneous customer accounts expenses	
Community Relations		
5405	Supervision	
5410	Community relations: sundry	
5415	Energy conservation	
5420	Community safety programme	
5425	Miscellaneous customer service and informational expenses	
Administrative and General Expenses		
5605	Executive salaries and expenses	
5610	Management salaries and expenses	
5615	General administrative salaries and expenses	

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Table B.2 Listing of Distribution distribution Accounts Related to the Working Capital Calculation		
Account Number	**Account Name**	**Year-End Amount**
5620	Office supplies and expenses	
5625	Administrative expense transferred: credit	
5630	Outside services employed	
5635	Property insurance	
5640	Injuries and damages	
5645	Employee pensions and benefits	
5650	Franchise requirements	
5655	Regulatory expenses	
5660	General advertising expenses	
5665	Miscellaneous general expenses	
5670	Rent	
5675	Maintenance of general plant	
5680	Electrical safety authority fees	
5685	Independent Market Operator fees	
568**X**	Other amounts no listed above – please provide details	
	Cost of Power and Controllable Expenses: Total	
	Working Capital Allowance (15% of Total above)	

The following table lists accounts and related amounts that are generally **not** considered necessary for the conveyance of electricity for rate-making purposes, and, consequently, are not considered to be distribution-related expenses or included in the calculation of working capital.

Note that, for the purpose of the working capital calculation above, any account listed below that pertains to both distribution and to non-utility purposes must be prorated between the uses, and the portion related to distribution should be included in Table B.2 under "Other amounts not listed above." The method of allocation should be reasonable and documented.

Non-Utility Expenses	
Account	**Account Name**
4505	Operation supervision and engineering
4510	Fuel
4515	Steam expense
4520	Steam from other sources
4525	Steam transferred: credit
4530	Electric expense
4535	Water for power
4540	Water power taxes
4545	Hydraulic expenses
4550	Generation expenses
4555	Miscellaneous power generation expenses
4560	Rents
4565	Allowances for emissions
4605	Maintenance supervision and engineering
4610	Maintenance of structures
4615	Maintenance of boiler plant
4620	Maintenance of electric plant
4625	Maintenance of reservoirs, dams, and waterways
4630	Maintenance of water wheels, turbines, and generators

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Non-Utility Expenses	
Account	**Account Name**
4635	Maintenance of generating and electric plant
4640	Maintenance of miscellaneous power generation plant
4720	Other expenses
4805	Operation supervision and engineering
4810	Load dispatching
4815	Station buildings and fixtures expenses
4820	Transformer station equipment: operating labour
4825	Transformer station equipment: operating supplies and expense
4830	Overhead line expenses
4835	Underground line expenses
4840	Transmission of electricity by others
4845	Miscellaneous transmission expense
4850	Rents
4905	Maintenance supervision and engineering
4910	Maintenance of transformer station buildings and fixtures
4916	Maintenance of transformer station equipment
4930	Maintenance of towers, poles, and fixtures
4935	Maintenance of overhead conductors and devices
4940	Maintenance of overhead lines: right of way
4945	Maintenance of overhead lines: roads and trails repairs
4950	Maintenance of overhead lines: snow removal from roads and trails
4960	Maintenance of underground lines
4965	Maintenance of miscellaneous transmission plant
5014	Transformer station equipment: operation labour
5015	Transformer station equipment: operation supplies and expenses
5030	Overhead sub-transmission feeders: operation (related to lines over 50 kV)

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Non-Utility Expenses	
Account	**Account Name**
5050	Underground sub-transmission feeders: operation (related to lines over 50 kV)
5060	Street lighting and signal system expense
5112	Maintenance of transformer station equipment
5120	Maintenance of poles, towers, and fixtures (related to lines 50 kV)
5125	Maintenance of overhead conductors and devices (related to lines over 50 kV)
5145	Maintenance of underground conduit (related to lines over 50 kV)
5150	Maintenance of underground conductors and devices (related to lines over 50 kV)
5165	Maintenance of street lighting and signal systems
5170	Sentinel lights: labour
5172	Sentinel lights: materials and expenses
5178	Customer installations expenses: leased property
5185	Water heater rentals: labour
5186	Water heater rentals: materials and expenses
5190	Water heater controls: labour
5192	Water heater controls: materials and expenses
5195	Maintenance of other installations on customer premises

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Appendix C: Amortization Rates

The amortization rates below apply to the respective assets listed under "Asset Type". All rates are based on the straight line method of amortization.

The inclusion of an asset in the chart below does not imply Board acceptance of the asset for inclusion in the Rate Base or for any other rate making purpose.

The amortization expense related to an asset used for both Distribution and Non-utility activities should be properly allocated to each type of activity. Only the amortization expenses related to distribution assets may be included as an expense in rate applications. The method of allocation should be reasonable and documented.

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		Effective January 1, 1992		Prior to January 1, 1992	
USoA Account	**Asset Type**	**Life-Years**	**Rate**	**Life-Years**	**Rates**
1930	Rolling Stock and Equipment[1]				
	Automobiles	4	25.00%	4	25.00%
	Trucks under 3 tonnes	5	20.00%	5	20.00%
	Trucks 3 tonnes and over	8	12.50%	8	12.50%
1950	Work and service equipment	8	12.50%	8	12.50%
Part of 1620, 1708, 1808, 1908 (as applicable)	Buildings and fixtures: brick, stone, concrete, and steel	50	2.00%	60	1.67%
1920, 1925	Computer equipment	5	20.00%	5	20.00%
1830, 1835, part of 1855	Distribution lines and feeders: overhead	25	4.00%	25	4.00%
1840, 1845, part of 1855	Distribution lines and feeders: underground	25	4.00%	25	4.00%
1860	Distribution meters	25	4.00%	25	4.00%
1850	Distribution transformers	25	4.00%	25	4.00%
1915	General office equipment	10	10.00%	10	10.00%
1635 to 1685	Generating stations	60	1.67%	60	1.67%
1615, 1705, 1805, 1905	Land	Non-depreciable		Non-depreciable	
1630, 1710, 1810, 1910	Leasehold improvements	Over term of lease		Over term of lease	
1970	Load management controls: customer premises	10	10.00%	15	6.67%
1975	Load management controls: utility premises	10	10.00%	15	6.67%
1940	Miscellaneous equipment, major tools, and instruments	10	10.00%	10	10.00%
1820	Municipal distribution station equipment (below 50 kV)	30	3.33%	30	3.33%
1815, 1715	Municipal transformer stations equipment (above 50 kV)	40	2.50%	40	2.50%
1985	Sentinel lighting rental units	10	10.00%	10	10.00%
1935	Stores warehouse equipment	10	10.00%	10	10.00%

[1] No allowance will be made for residual value.

		Effective January 1, 1992		Prior to January 1, 1992	
USoA Account	**Asset Type**	**Life-Years**	**Rate**	**Life-Years**	**Rates**
Below 50 kV relates to part of 1720, 1725, and 1735 Above 50 kV relates to 1830 and 1835	Sub-transmission feeders: overhead	25	4.00%	25	4.00%
Below 50 kV relates to 1840 and 1845 Above 50 kV relates to 1735 and 1740	Sub-transmission feeders: underground	25	4.00%	25	4.00%
1980	System supervisory equipment	15	6.67%	25	4.00%
Part of 1725 and 1730	Transmission lines: wood poles	25	4.00%	25	4.00%
1965	Water heater rental units	10[2]	10.00%	10[2]	10.00

[2] In areas where water conditions are deemed to affect the life of water heaters, a different depreciation rate may be approved. Applicants will be required to file full details as to the determination of such a rate. **(*Is this still necessary?)***

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Appendix E: <u>Distribution Activities</u>

This appendix may be updated to reflect new accounts.

<u>Definition of Distribution Activities</u>

Activities that enable the conveyance of electricity for distribution purposes will be considered to be distribution activities. In consequence, expenses incurred in relation to the provision of these activities are defined as distribution expenses.

<u>Distribution Activities</u>

The following activities are generally considered to be distribution activities:

- operation and management of the distribution system
- meter reading services, including verification, testing, approval, and installation and removal services
- billing and collection services
- line-clearing services
- repair and maintenance for the distribution lines and facilities
- planning, design, and construction of distribution lines and facilities, including system planning and load forecasting services
- general administrative support services, including corporate services such as management, payroll, regulatory compliance service, etc..
- telecommunications services for electricity distribution (e.g. SCADA and remote metering
- energy efficiency services that are approved by the Board, including Conservation and Demand Management programmes
- customer care services, including call centre services
- energy education services
- services required under other Board codes or guidelines

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- other services that satisfy the above definition of distribution activities

The following is a list of distribution expense accounts as found in the Accounting Procedures Handbook and in the USoA listings.

Note: The list of accounts below may need to be updated when the final 2006 Handbook is issued.

Account Number	Account Description
5005	Operation Supervision and Engineering
5010	Load Dispatching
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment -- Operation Labour
5015	Transformer Station Equipment -- Operation Supplies and Expenses
5016	Distribution Station Equipment -- Operation Labour
5017	Distribution Station Equipment -- Operation Supplies and Expenses
5020	Overhead Distribution Lines and Feeders -- Operation Labour
5025	Overhead Distribution Lines and Feeders -- Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders -- Operation
5035	Overhead Distribution Transformers -- Operation
5040	Underground Distribution Lines and Feeders -- Operation Labour
5045	Underground Distribution Lines and Feeders -- Operation Supplies and Expenses
5050	Underground Subtransmission Feeders -- Operation
5055	Underground Distribution Transformers -- Operation
5065	Meter Expense
5070	Customer Premises -- Operation Labour
5075	Customer Premises -- Materials and Expenses
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders -- Rental Paid
5095	Overhead Distribution Lines and Feeders -- Rental Paid
5096	Other Rent
5105	Maintenance Supervision and Engineering
5110	Maintenance of Buildings and Fixtures -- Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5130	Maintenance of Overhead Services
5135	Overhead Distribution Lines and Feeders -- Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5155	Maintenance of Underground Services
5160	Maintenance of Line Transformers
5175	Maintenance of Meters
5205	Purchase of Transmission and System Services

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5210	Transmission Charges
5215	Transmission Charges Recovered
5305	Supervision
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting- Cash Over and Short
5330	Collection Charges
5335	Bad Debt Expense
5340	Miscellaneous Customer Accounts Expenses
5405	Supervision
5410	Community Relations -- Sundry
5415	Energy Conservation
5420	Community Safety Program
5425	Miscellaneous Customer Service and Informational Expenses
5505	Supervision
5510	Demonstrating and Selling Expense
5515	Advertising Expense
5520	Miscellaneous Sales Expense
5605	Executive Salaries and Expenses
5610	Management Salaries and Expenses
5615	General Administrative Salaries and Expenses
5620	Office Supplies and Expenses
5625	Administrative Expense Transferred Credit
5630	Outside Services Employed
5635	Property Insurance
5640	Injuries and Damages
5645	Employee Pensions and Benefits
5650	Franchise Requirements
5655	Regulatory Expenses
5660	General Advertising Expenses
5665	Miscellaneous General Expenses
5670	Rent
5675	Maintenance of General Plant
5680	Electrical Safety Authority Fees
5685	Independent Market Operator Fees and Penalties
6205	Donations
6210	Life Insurance
6215	Penalties
6225	Other Deductions
6305	Extraordinary Income
6310	Extraordinary Deductions
6405	Discontinued Operations -- Income/Gains
6410	Discontinued Operations -- Deductions/Losses