Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Ontario Energy Board

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications

June 22, 2011

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Chapter 2 Filing requirements for electricity transmission and distribution companies' cost of service rate applications, based on a forward test year

2.0 Preamble

The Ontario Energy Board establishes the rates and charges for electricity transmission and distribution companies using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service ("cost of service" or "CoS") reviews. For a cost of service review, forecasted test year data is normally used. Filing Requirements for IRM rate applications are provided in Chapter 3 of this document.

The Filing Requirements are generally intended to apply to both transmitters and distributors. Unless specifically identified, the use of the words "utility", "utilities", "applicant" or "applicants" in this document refers to both transmitters and distributors. However, some sections, such as cost allocation, are only applicable to distributors. These sections will use the word "distributor" when referring to the filer.

An application to the Board by a regulated company should provide sufficient detail to enable the Board to make a determination as to whether the proposed rates are just and reasonable. The material presented is the applicant's evidence and the onus is on the applicant to prove the need for and prudence of the costs that are the basis of the proposed new rates. A clearly written application that demonstrates the need for the proposed rates, complete with sufficient evidence and justification for those rates, is essential to facilitate an efficient regulatory review and a timely decision.

The use of the phrase "Board-approved" in these filing requirements typically refers to the set of data used by the Board as the basis for approving the most recent cost based rates. It does not mean that the Board, in fact, "approved" any of the data, but only that the final approved rates were based on that data.

The examination of an application and the subsequent decision are based only on the evidence filed in that case. This ensures that all interested parties to the proceeding have an opportunity to see the evidence, participate meaningfully in the Board's process in any given case and understand the reasons for a decision. Consequently, the applicant must, at a minimum, meet all of the applicable Filing Requirements.

The purpose of the interrogatory process is to test the evidence before the Board, and not to complete the initial pre-filed record. The Board will consider an application complete if it meets <u>all</u> of the applicable Filing Requirements. If an application does not meet <u>all</u> of these requirements, the applicant must provide an explanation as to why this is the case. Based on this explanation, the Board will assess whether or not the application can proceed.

The Filing Requirements contained in this chapter outline all of the relevant information necessary for a complete cost of service-based application. Sections 2.1 and 2.2 address issues related to certain non-standard applications. Section 2.1 addresses the matter of an applicant seeking to make a cost of service rebasing application prior to the end of the IRM term. Section 2.2 addresses the issue of an applicant seeking an effective date other than May 1 of the test year. Beginning with Section 2.3, the filing requirements for the application itself are outlined. Section 2.3 provides an Introduction, including an overview of general requirements and information on key planning parameters. Sections 2.4 to 2.12 provide requirements for each of the major exhibits covered by the application (e.g., Section 2.6 addresses operating revenue, while Section 2.10 addresses cost allocation).

The various appendices referenced in the chapters are linked to each of these sections and provide schedules to be completed by the applicant to facilitate the filing of all required information (e.g., Appendix 2-O Cost Allocation provides tables related to Revenue-to-Cost Ratios and Test Year Revenue Impacts). These appendices are available in Excel format on the Board's web site and should be completed by applicants and filed as part of a CoS application.

Any application made pursuant to section 92 (i.e. Leave to Construct) of the *Ontario Energy Board Act, 1998* (the "OEB Act") is subject to the requirements of chapters 4 and 5 of the Filing Requirements (see Section 2.5 dealing with capital budgets for projects with construction commencing in the Test Year).

When changes or updates to a filing are necessary, a thorough explanation of the changes must be provided, along with revisions to the affected evidence and related schedules. This process is contemplated in Rule 11.02 of the *Rules of Practice and Procedure*. When these changes or updates are contemplated late in a proceeding, applicants should proceed with the update only if there is a material change to the evidence already before the Board. Rule 11.03 states that any such updates should clearly indicate the date of the revision and the part revised.

The Board remains cognizant of the large number of interrogatories that the existing process can generate. The frequent requirement for a large number of interrogatories suggests that applicants and interested parties do not have a common understanding of the information required to support a rate application. The Board advises applicants to strategically consider the clarity and materiality of the evidence, so that the evidence can be well understood by all parties, thereby reducing the need for interrogatories. The Board also advises parties to carefully consider the relevance of their interrogatories when assessing an application.

Where an applicant is requested by a party to file information that the applicant believes is not relevant to the proceeding, the applicant may file and serve a response to the interrogatory that sets out the reasons for the applicant's belief that the requested information is not relevant. This process is contemplated in Rule 29 of the *Rules of Practice and Procedure* and applies to all interrogatories.

In order to facilitate an efficient review of interrogatories and responses, the filing of interrogatories and responses must be sorted by issue. (For example, all interrogatory responses on test year capital budget should be grouped together, regardless of which party submitted the interrogatory.) In the absence of a Board-approved Issues List, parties must sort their interrogatories and responses by topic as outlined in the exhibits in this Filing Requirement document. This process is also contemplated in Rule 29 of the *Rules of Practice and Procedure* and applies to all interrogatories.

2.1 Cost of Service Application in Advance of Scheduled Application

On April 20, 2010, the Board issued a letter entitled *Early Rebasing Applications* addressing the issue of electricity distributors intending to file rate applications to have their rates set through a cost of service proceeding earlier than would normally be scheduled in the multi-year plan for cost of service and IRM rate applications. Currently, it is normally intended that an applicant will file for a cost of service rebasing once every four years, followed by three years of IRM rate adjustments.

The letter noted that, while the Board's rate-setting policies are such that distributors are expected to be able to adequately manage their resources and financial needs during the term of their IRM plan, the Board's multi-year rate setting approach does contemplate that some distributors may legitimately need to have their rates rebased earlier than originally scheduled, by making provision for an "off-ramp". The Board stated that the conditions under which the "off-ramp" would be applicable reflected the Board's view of circumstances that would justify a departure from the normal 4-year plan schedule and necessitate an early cost of service rebasing.

The letter stated that a distributor seeking to have its rates rebased in advance of its next regularly scheduled cost of service proceeding, notwithstanding that the "off ramp" conditions have not been met, must justify in its cost of service application why an early rebasing is required. Specifically, the distributor would be expected to demonstrate clearly why and how it could not adequately manage its resources and financial needs during the remainder of its IRM plan period. The letter further advised distributors that the panel of the Board hearing such an application may consider it appropriate to determine, as a preliminary issue, whether the application for rebasing is justified or whether the application as framed should be dismissed. Distributors were also advised that the Board might, where an application for early rebasing did not appear to be justified, disallow some or all of the regulatory costs associated with the preparation and hearing of that application.

The Board issued early rebasing decisions related to three such applications for the 2011 rate year. It is recommended that distributors contemplating an early rebasing application for 2012 rates first review these decisions before deciding to proceed with such an application.

2.2 Seeking Approval for an Effective Date Other Than May 1 of the Test Year

On April 15, 2010, the Board issued a letter entitled *Alignment of Rate Year with Fiscal Year for Electricity Distributors*. In the letter, the Board concluded it would be appropriate to consider the merits of an alignment of the rate year with the fiscal (calendar) year for distributors on a case-by-case basis upon receipt of an application for that purpose as part of a distributor's cost of service rate application.

The letter further stated that the Board expected the distributor to include in such an application an analysis of the benefits and ratemaking implications, if any, of the proposed alignment. Appendix B of the letter contained examples of the issues that were to be addressed.

If a January 1st implementation date is being requested in order to align the rate year with the fiscal year, the Board would normally expect such applications to be filed no later than by the end of April prior to the test year in order to allow sufficient time for the review of the application.

2.3 Introduction

The basic format of an application for a forward test year cost of service filing should consist of the following nine Exhibits:

Exhibit 1	Administrative Documents
Exhibit 2	Rate Base
Exhibit 3	Operating Revenue
Exhibit 4	Operating Costs
Exhibit 5	Cost of Capital and Capital Structure
Exhibit 6	Calculation of Revenue Deficiency/Sufficiency
Exhibit 7	Cost Allocation
Exhibit 8	Rate Design
Exhibit 9	Deferral and Variance Accounts

These exhibits correspond with the elements of a cost of service application, which is intended to establish rates that recover a revenue requirement based on an estimate of demand for the test year. A schematic of the elements of a cost of service application is provided in Appendix 2-W.

If any significant element of these filing requirements is not included in the filing, the application may be deemed by the Board to be incomplete and may not be processed until the missing information is provided.

Other exhibits may also be included in an application to document other proposals for which the applicant is seeking Board review and approval. These could be related to, for example, Lost Revenue Adjustment Mechanism and Shared Savings Mechanism recoveries. Guidance on the material to be included in such exhibits is provided through applicable guidelines or other documentation that the Board may provide, or that may be contained in applicable legislation or regulation.

The Filing Requirements incorporate a series of appendices which include tables required to be completed by the applicant. These tables are available on the Board's web site.

2.3.1 Key References

The references listed below are key to interpreting these Filing Requirements.

- Generally Accepted Accounting Principles ("GAAP");
- International Financial Reporting Standards ("IFRS");
- Report of the Board on the Transition to International Financial Reporting Standards, July 28, 2009 and implementation update, outlined in section 2.3.5 below;
- Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (EB-2008-0408), June 13, 2011;
- The Board's Accounting Procedures Handbook ("APH") and Uniform System of Accounts ("USoA"), any subsequent updates and Frequently Asked Questions;
- Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084), December 11, 2009 and any subsequent updates;
- Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008;
- Supplemental Report, and Addendum, of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008 and January 28, 2009;
- Cost Allocation Informational Filing Guidelines for Electricity Distributors, November 15, 2006;
- Application of Cost Allocation for Electricity Distributors, November 28, 2007;
- Review of Electricity Distribution Cost Allocation Policy: Report of the Board (EB-2010-0219), March 31, 2011;
- Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative (EB-2008-0046), July 31, 2009;
- Smart Meter Funding and Cost Recovery Guideline (G-2008-0002), October 22, 2008, and any subsequent updates;
- *Green Energy and Green Economy Act* Initiatives outlined in Section 2.3.4 below;

- Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037), March 28, 2008;
- Electricity Distribution Retail Transmission Service Rates *Guideline* (G-2008-0001), October 22, 2008 and any subsequent updates;
- Depreciation Study for Use by Electricity Distributors (EB-2010-0178), the “Kinectrics Report,” July 8, 2010;
- Board letter of April 15, 2010, providing guidance to electricity distributors on the alignment of the rate year with fiscal year (EB-2009-0423).

2.3.2 General Requirements

The requirements outlined below are general requirements that are applicable throughout the application:

- Written direct evidence is to be included before data schedules;
- Average of the opening and closing fiscal year balances must be used for items in rate base;
- Total Capitalization (debt and equity) must equate to Total Rate Base;
- Data for the following years, at a minimum, must be provided:
    - Test Year = Prospective Rate Year;
    - Bridge Year = Current Year;
    - Three Most Recent Historical Years (or number of years necessary to provide actuals back to and including the most recent Board Approved Test Year, but not less than three years);
    - Most recent Board Approved Test Year;
- A statement is to be provided as to when the forecast was prepared and when it was approved by the utility’s management and/or Board of Directors for use in the application;
- Multi-year data for each of the above-referenced years is to be presented on the same sheet for the summary/main schedules;
- A detailed year-over-year variance analysis is to be provided between the Test Year and Bridge Year, the Historical Year(s) and the last Board Approved Test Year, including reasons/drivers of variances and the contribution of each driver towards the total year-over-year variance;
- Calculations of revenue sufficiency/deficiency;
- For Board-prescribed values, such as ROE and deemed debt rates, the most recent values available from the Board are to be used as applicable with an accompanying statement that they will be updated as required. If an applicant is proposing to use values and methodologies different from the standard Board policy and practice, this proposal should be clearly stated and reasons/ supporting evidence provided;
- The most recent Board-approved RPP and an estimate for non-RPP (at the time of filing) is to be used for the electricity commodity price;
- Changes to accounting policies made since the applicant’s last cost of service filing are to be identified and a summary of the impacts of any such changes is to

be provided (these include any changes on adoption of IFRS effective January 1, 2012 for which the Board has provided further direction);
- Changes in legal organization or control must be identified;
- Changes in tax status (e.g. a change from a corporation to a limited partnership) must be disclosed;
- Any orders or directions outstanding from previous Board Decisions or Orders are to be identified and addressed; and
- Tables should be provided in Excel spreadsheet format.

2.3.3 Confidential Information

The Board relies on full and complete disclosure of all relevant material in order to ensure that its decisions are well-informed. The Board recognizes that applicants may consider some of that information to be confidential and may wish to request that it be protected. In such cases, the relevant rules in the Board's *Rules of Practice and Procedure* and the procedures set out in the Board's *Practice Direction on Confidential Filings* are to be followed by all participants in a proceeding before the Board, unless otherwise directed by the Board.

The onus is on the applicant or entity requesting confidential treatment to demonstrate to the satisfaction of the Board that confidential treatment is warranted. It is the Board's expectation that a party will make every effort to limit the scope of its confidentiality requests to an extent commensurate with the commercial sensitivity of the information at issue or with any legislative obligations of confidentiality or non-disclosure. The applicant or entity making such a request must prepare meaningful redacted documents or summaries so as to maximize the information that is available on the public record. This will provide all interested parties with a fair opportunity to present their cases and will permit the Board to provide meaningful and well-documented reasons for its decisions.

The applicant or entity requesting confidential treatment must address such requests to the Board Secretary and include the following items as set out in the Practice Direction. The applicant should review the Practice Direction in order to ensure that all requirements related to confidential information have been met:

- A cover letter indicating the reasons for the confidentiality request;
- A confidential, un-redacted version of the document containing all of the information for which confidentiality is requested and which is identified by either shading or other easily identifiable means; and
- A non-confidential, redacted version of the document from which the information that is the subject of the confidentiality request has been deleted or stricken, or, where the request for confidentiality relates to the entire document, a non-confidential description or summary of the document.

A copy of the cover letter requesting confidentiality, together with the non-confidential version or non-confidential description of the document (as applicable) must be served on all parties to the proceeding, and will be placed on the public record.

The Board and parties to a proceeding are required to devote additional resources to the administration, management and adjudication of confidentiality requests and confidential filings. Applicants should ensure that filings for which they intend to request confidential treatment are clearly relevant to the proceeding.

Parties should also take note of the requirements related to relevance of interrogatories outlined in the Preamble, which are also applicable to information which is requested and raises confidentiality concerns.

2.3.4 Green Energy Act Requirements

A distributor filing a cost of service rate application for 2012 or subsequent rate years must file with the Board a Green Energy Act Plan ("GEA Plan") as part of such an application. The requirements for the filing are described in the Board's March 25, 2010 *Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence* (EB-2009-0397).

A distributor should also consult recent decisions issued by the Board related to GEA expenditures as well as the following documents with respect to requirements arising from amendments to the OEB Act made by the *Green Energy and Green Economy Act, 2009* and related Board initiatives that may affect their 2012 cost of service applications:

- *Distribution System Code Amendments* (EB-2009-0077), October 21, 2009.

    The Board's amendments to the *Distribution System Code* which revised the Board's approach to assigning cost responsibility between distributors and generators in relation to the connection of renewable generation facilities.

- *Conservation and Demand Management Code* (EB-2010-0215), Sept. 16, 2010.

    The Board's CDM Code is designed to ensure that distributors meet their CDM targets in a way which is cost effective and provides value to ratepayers.

- *Electricity Conservation and Demand Management Targets (EB-2010-0216),* June 22, 2010 and *Decision and Order (EB-2010-0215/EB-2010-0216)* March 14, 2011.

- *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* (EB-2009-0349), June 10, 2010.

Section 79.1 of the OEB Act provides for rate protection for customers of a distributor that incurs costs to make an eligible investment for the connection of qualifying generation facilities. The Board Report sets out a framework for the Board's approach to the determination of the "direct benefits" that accrue to those customers as a result of all or part of the eligible investment made or planned to be made by the distributor. This will represent the allocation of eligible investment costs to the distributor's ratepayers, with the remaining costs allocated to provincial ratepayers.

A distributor that incurs costs to make an eligible investment shall provide a calculation of the direct benefits of that investment accruing to the distributor's customers for the test year, consistent with the Board Report, as well as the remaining eligible investment costs to be recovered from provincial ratepayers.

- *Decision and Order with Respect to a microFIT Generator Rate* (EB-2009-0326), February 23, 2010.

In its Decision and Order issued February 23, 2010, the Board established a service classification for microFIT Generation accounts, which is to be used by all licensed distributors. On March 17, 2010, the Board issued its Rate Order, which approved a single province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator rate class at $5.25 per month, effective September 21, 2009.

A distributor should include revenue arising from this charge as "Other Revenue" in its application.

- *Filing Requirements for Transmission Project Development Plans* (EB-2010-0059), August 26, 2010;

This document sets out the policy of the Board for a framework for new transmission investment in Ontario, in particular with regard to transmission project development planning and describes how project development planning will work in conjunction with existing Board processes for licensed transmitters.

- *The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario* (EB-2009-0152), January 15, 2010.

The regulatory framework set out in this Report builds on the Board's rate-making framework by augmenting "conventional" cost recovery mechanisms with a range of "alternative" cost recovery mechanisms designed to facilitate appropriate infrastructure investment by distributors and transmitters.

- *Guidelines for Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities* (G-2009-0300), September 15, 2009.

  These Guidelines describe the ownership scenarios available in relation to the ownership of generation and energy storage facilities described in section 71(3) of the OEB Act ("qualifying facilities") and set out the regulatory and accounting requirements applicable to each scenario. Qualifying facilities may be owned directly by a distributor, or may be owned by an affiliate of the distributor. Under the affiliate ownership scenario, a distributor would need only to review its policies, procedures and processes to ensure compliance with the *Affiliate Relationships Code for Electricity Distributors and Transmitters.*

  The ownership and operation of qualifying facilities is not a rate-regulated activity. Accordingly, if a distributor chooses to own and operate a qualifying facility directly as part of its business, costs would not be recovered through rates and a regulatory return would not be earned on the investment. For rate setting purposes, the distributor would need to file financial information in its rate application that clearly delineates the distributor's regulated activities from its non-rate related activities, as outlined in the Guidelines. For greater clarity, the distributor would need to file financial information for the consolidated utility, and individual statements for rate regulated activities and non-rate regulated activities on a pro-forma basis for the test period. By individual statements, the Board intends that separate financial information should be filed, not separate audited financial statements.

- Distributor-owned Generation (EB-2009-0411) Notice of Amendments to Codes, March 11, 2010;

  The Board issued amendments to the *Distribution System Code* and the *Affiliate Relationships Code for Distributors and Transmitters* ("ARC") to keep pace with the fact that electricity distributors are now permitted to own qualifying facilities. The amendments provide for certain provisions of the ARC to no longer apply in terms of dealings between a distributor and an affiliate in relation to activities associated with qualifying facilities. Also, the amendments ensure that distributors treat their own generation facilities in the same manner as they would treat generation facilities owned by third parties.

A distributor should incorporate a separate section in its application providing an overview of any proposals with respect to renewable generation connection plans, or smart grid plans that will have an impact on the application. This overview should summarize the key elements of any proposals made and their impacts on the application. These key impacts should also be broken out separately from the remaining costs in the relevant sections of the application (e.g. OM&A impacts arising from a GEA plan should be identified separately from the remaining OM&A costs, as discussed subsequently). A proposal seeking approval for a GEA plan should also clearly identify the period for which the distributor is seeking prudence review and approval, and the distributor's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.3.5 Transition to International Financial Reporting Standards ("IFRS")

Applicants should refer to the following documents for detailed guidance relating to the use of IFRS in application filings:

- *Report of the Board: Transition to IFRS;* dated July 28, 2009 ("Board Report");
- Clarification letter regarding accounting for overhead costs associated with capital work, dated February 24, 2010;
- Amendment to reflect Accounting Standards Board decision to permit a delay in adopting IFRS to January 1, 2012; Board letter dated November 8, 2010;
- Amendment with respect to the use of Modified IFRS as a basis for filing Cost of Service Applications for 2012 rates; per letter dated March 15, 2011;
- Asset Depreciation Study done by Kinectrics Inc for distributors sponsored by the Board for distributors, dated June 15, 2010; and
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment* ("Addendum"), dated June 13, 2012. Most issues addressed in the Addendum relate to cost of service applications as well as IRM applications.

Applicants should state whether they have filed their applications on the basis of modified IFRS, CGAAP, or another accounting system.

On March 15, 2011, the Board issued its letter entitled *Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates.* This letter expressed the Board's belief that distributors whose rates are being rebased for 2012 should make all reasonable efforts to file test year forecasts for their cost of service applications using modified IFRS. The Board noted that, since utilities must transition to IFRS in 2012 for financial reporting purposes, the filing of a cost of service application using the same accounting system as is required to be used in a distributor's financial statements is expected to minimize future complexities and associated costs.

The Board's letter further stated that a distributor, for whom preparing a modified IFRS-based application would impose an unreasonable burden, might file under CGAAP but must provide an explanation of this choice as part of its rate application filing.

The Board determined that it would not extend the timelines for the filing for cost of service applications to allow distributors who had been preparing 2012 applications to make the necessary changes from CGAAP to IFRS, in order to ensure that the Board's ability to implement distribution rates by the applied-for dates would not be compromised. However, the Board did state that for distributors seeking new rates effective January 1, 2012 and which were expected to file their cost of service applications by April 29, 2011, it would, when approving an effective date for 2012 rates, consider any reasonable delay in filing caused by additional work to file on the basis of modified IFRS.

Utilities are required to identify in their rates application the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. The particulars of this requirement are set out in the Board Report, the amendments posted November 8, 2010 and March 15, 2011 and the Addendum listed above.

2.4 Exhibit 1. Administrative Documents

The administrative documents identified in this section provide the background and summary to the case as filed. Administrative documents consist of four sections:

1) Administration;
2) Overview of the filing;
3) Financial information; and
4) Materiality thresholds.

2.4.1 Administration

This section should include the following:

- Table of Contents;
- Application;
- Statement as to which publication(s) the applicant proposes that notice should appear, whether it is a paid publication or not and the readership and circulation numbers;
- Contact information. The primary contact for the application may be a person within the applicant's organization other than the primary licence contact. The Board will communicate with this person during the course of the application. After completion of the application, the Board will revert communication to the primary licence contact;
- List of specific approvals requested. All approvals including accounting orders which the applicant is seeking should be separately identified in this exhibit and clearly documented in the appropriate section of the application;
- Statement as to whether or not the distributor has had any transmission assets (> 50kV) deemed previously by the Board as distribution assets and whether or not

there are any such assets for which the distributor is seeking Board approval to be deemed as distribution assets in the present application;

- Proposed Issues List;
- Accounting Orders and List of any departures from the Uniform System of Accounts including references to Accounting Orders;
- Description of applicant's operating environment:
  - General description and map showing where the utility operates within the province, and the communities serviced by the utility. A utility may provide more detailed geographic and/or engineering maps where these may be useful to understand parts of the application, such as a capital expansion or replacement program;
  - A list of neighbouring utilities;
  - A description of whether the utility is a host utility (i.e. transmitting electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e. receiving electricity at distribution-level voltages from any host distributor). The utility should identify the embedded and/or host distributor(s). Partially embedded status should also be clearly identified, including the percentage of load that is supplied through the host distributor;
- Corporate and Utility Organizational Structure:
  - High-level utility organization chart, showing the main units and executive and senior management positions within the utility;
  - Corporate Entities Relationship Chart, showing:
    - the organization of any associated or affiliated entities with respect to each other;
    - the extent to which the parent company is represented on the utility company board;
    - the reporting relationships between utility management and parent company officials;
    - the services and the nature of the services provided to/by affiliated entities; and
    - any shared services among the affiliated entities, including the extent to which the applicant is a "virtual" utility;
  - Planned changes in corporate or operational structure;
  - If an applicant is conducting non-utility businesses, such as generation, it must confirm that the accounting treatment it has used has segregated all of these activities from its rate-regulated activities. Distributors owning generation facilities should consult the Board's *Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities* G-2009-0300, September 15, 2009;
- Identification of Board Directives from any previous Board Decisions and/or Orders. The applicant should clearly indicate how these are being addressed in the current application (e.g. filing of a study as directed in a previous Decision); and
- Reference to the applicant's Conditions of Service. The applicant does not need to file its Conditions of Service, but should provide a reference to where its

Conditions of Service are publicly available (e.g. on the utility's website), and confirm that this is the current version. The utility should identify if there are any rates and charges documented in its Conditions of Service. If there are changes to its Conditions of Service that would change as a result of approval of the application, the applicant must identify all such changes.

2.4.2 Overview

This section should include the following:

- Summary of Application (purpose, need, timing and key elements of the application and typical customer impact by customer class);
- Budget Overview (Capital & Operating):
  - Budget directives and guidelines; and
  - Economic assumptions used;
- Changes in methodology from previous applications or established Board practice or policy (e.g. accounting, normalization, etc.);
- Schedule of overall revenue sufficiency/deficiency; and
- Revenue Requirement Work Form. The link on the Board's website may be used to access this work form.

2.4.3 Financial Information

This section should include the following:

- Audited Financial Statements of the utility (non-consolidated from affiliated companies) for which the application has been made, for the two most recent historical years (i.e. both year's statements must be filed covering three years of historical actuals). If the statements are not available at the time of filing, they must be provided as soon as they are available;
- *Pro Forma* Financial Statements for the Bridge and Test Years;
- Detailed reconciliation of the financial results shown in the Annual Reports/ Audited Financial Statements with the regulatory financial results filed in the application including a reconciliation of the fixed assets, for example in order to separate non-utility businesses. This should include the identification of any deviations between the Annual Reports/Audited Financial Statements and the regulatory financial statements that are being proposed including the identification of any prior Board approvals for such deviations that may exist;
- Annual Report and Management's discussion and analysis, for the most recent year, of the parent company;
- Rating Agency Report(s), if available; and
- Prospectuses, information circulars, etc. for recent and planned public issuances.

2.4.4 Materiality Thresholds

The applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.

Unless a different threshold applies to a specific section of these Filing Requirements, the default materiality thresholds are as outlined in the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors of September 17, 2008* (EB-2007-0673) and are reproduced below:

- $50,000 for a distributor with a distribution revenue requirement less than or equal to $10 million;
- 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million; and
- $1 million for a distributor with a distribution revenue requirement of more than $200 million.

If an applicant believes that an alternative threshold would be appropriate to its specific circumstances, it is free to propose such an alternative, with appropriate justification, in its application.

2.5 Exhibit 2. Rate Base

This exhibit includes information on:

1) Rate Base;
2) Capital Expenditures; and
3) Service Quality and Reliability Performance.

2.5.1. Rate Base

2.5.1.1 Overview

For rate base, the applicant must include the opening and closing balances, and the average of the opening and closing balances for gross assets and accumulated depreciation. Rate base shall also include an allowance for working capital.

At a minimum, the filed material in support of the requested rate base must include data for the Historical Actuals, Bridge Year (actuals to date and balance of year as budgeted), and Test Year.

Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include interest during construction, and all overheads. Variance analyses must provide a written explanation for rate base-related material when there is a variance greater than the applicable materiality threshold.

If continuity statements have been re-stated for the purposes of the application, the utility must provide a thorough explanation for the restatement and provide a reconciliation to the original statements.

The following comparisons must be provided:

- Historical Board-approved vs. Historical Actual (for most recent historic Board-approved year);
- Historical Actual vs. preceding Historical Actual (for the relevant number of years);
- Historical Actual vs. Bridge; and
- Bridge vs. Test Year.

The information outlined in Appendix 2-B should be provided for each year.

2.5.1.2 Gross Assets – Property Plant and Equipment

The applicant must provide the following information:

- Breakdown by function (transmission plant, distribution plant, general plant, other plant) for required statements and analyses;
- Detailed breakdown by major plant account for each functionalized plant item. For the Test year, each plant item should be accompanied by a written description; and
- Summary of an incremental capital module adjustment, including what was approved and what was spent, if the applicant received approval for an incremental capital module adjustment as part of a previous 3rd generation IRM application.

2.5.1.3 Accumulated Depreciation

Continuity statements should be reconcilable to the calculated depreciation expenses (under Exhibit 4 – Operating Expenses) and presented by asset account.

2.5.1.4 Allowance for Working Capital

The applicant may take one of two approaches for calculation of its allowance for working capital: (1) the 15% allowance approach; or (2) the filing of a lead/lag study.

The only exception to the above requirement is if the applicant has been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based. Under such circumstances, the applicant must either continue to use the results of that study, or in the event it wishes to propose a revision to its allowance, the applicant must file an updated study in support of its proposal. In the absence of such circumstances the two approaches are:

15% Allowance Approach

The 15% Allowance Approach is calculated to be 15% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

The commodity price estimate used to calculate the Cost of Power should be determined in a way that bases the split between RPP and non-RPP customers on actual data. The calculation should also reflect the most recent Uniform Transmission Rates approved by the Board (EB-2010-0002), issued on January 18, 2011 and effective January 1, 2011. In the event that new Uniform Transmission Rates are approved during the course of a proceeding, the Cost of Power should be updated to reflect the new rates. The RPP Price that should be used should be the most current RPP Price issued by the Board and should apply to the entire test period forecast.

Lead/Lag Study

A lead/lag study analysis for two time periods; namely:

- The time between the date customers receive service and the date that the customers' payments are available to the distributor (the lag); and
- The time between the date when the distributor receives goods and services from its suppliers and vendors and the date that it pays for them (the lead).

Leads and lags are measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) days is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the distributor's rate base determination.

Cost of Service Applications for the 2013 Rate Year

The Board informs distributors that 2012 will be the final year for which the 15% Allowance Approach will be allowed as a default value. The Board is reviewing the possibility of requiring distributors to file lead/lag studies for the purpose of establishing the working capital allowance for the 2013 rate year.

2.5.1.5 *Treatment of Stranded Assets Related to Smart Meter Deployment*

The Board's *Guideline: Smart Meter Funding and Cost Recovery* (G-2008-0002) provides two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters: (1) leave them in rate base (i.e. Account 1860); or (2) record them in "Sub-account Stranded Meter Costs" of Account 1555.

Since the issuance of this guideline, most distributors have completed or nearly completed their smart meter deployments. Distributors are entitled to receive a rate of return for prudent investments in smart meters while recorded in Account 1555, from the time of their smart meter in-service deployment to the time of the disposition of the smart meters in rates. The earned return on the smart meter investments serves to recognize that the meters are used and useful while they are recorded in Account 1555, although they are not yet included in rate base.

Accounting guidance in the December 2010 Accounting Procedures Handbook FAQs (Q and A #15) provides information as to how the CoS rate-setting process may be used to address the recovery by distributors of costs associated with stranded meters.

The Board made findings on the treatment of stranded meters in both its Hydro One Brampton Networks Inc. (EB-2010-0132) *Decision and Order* of April 4, 2011 and its Kenora Hydro Electric Corporation (EB-2010-0135) *Decision and Order* of May 25, 2011, which are relevant to distributors making 2012 applications. Distributors should review these Decisions before filing their applications since they provide the general policy framework for the cost recovery of stranded meters going forward.

Distributors should file as part of their 2012 application a proposed treatment for the recovery of stranded meters that is in conformity with the approach taken by the Board as follows:

1. The total estimated NBV of the stranded meters as of December 31, 2011, or a revised amount calculated in accordance with the above-noted accounting guidance, should be removed from rate base (see Appendix 2-R). The 2012 revenue requirement should not include either a cost of capital return or depreciation expense associated with the total estimated stranded meter costs removed from rate base;
2. The total estimated NBV of the stranded meters should be recovered through separate rate riders for the applicable customer classes. A distributor must outline the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach;
3. The total estimated stranded meter costs should be tracked in "Sub-account Stranded Meter Costs" of Account 1555; and
4. The associated recoveries from the separate rate riders should also be recorded in this sub-account to reduce the balance in the sub-account.

In order to keep the distributor whole, as noted above, separate rate riders for the applicable customer classes should be proposed to recover the amount of the total estimated stranded costs. If the distributor has not completed 100% of its smart meter deployment at the time of the application, there will be a need for the approved stranded meter estimated costs as of December 31, 2011 to be trued-up to actual stranded meter costs when the installation of all smart meters is completed. An adjusting entry should be recorded for this adjustment in the sub-account referenced above. The residual balance (net of recoveries) should be submitted for review as part of the distributor's next CoS application.

Distributors wishing to propose a different approach to that outlined above should provide a full explanation of the proposed approach and justification for it, including why the approach taken in the referenced Decisions would not be applicable to their circumstances.

2.5.2 Capital Expenditures

2.5.2.1 Overview

The applicant must provide an overall summary of capital expenditures over the past five historical years, the bridge year and the test year, showing capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress ("CWIP"). The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category. One suggested format for filing this material is in Appendix 2-A.

The following capital expenditure information should be provided by the applicant on a project specific basis:

- For projects over the applicable materiality threshold: need, scope, and purpose of project, related customer attachments, volumes and capital costs, as well as any applicable cost-benefit analysis;
- Detailed breakdown of starting dates and in-service dates for each project;
- Drivers of capital expenditure increases for the Test year;
- Where a proposed project requires Leave to Construct approval under Section 92 of the OEB Act, with construction commencement in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in section 4.3, section 4.4 and Chapter 5 of these Filing Requirements;
- Components of Other Capital Expenditures including a reconciliation of all capital components to the Total Capital Budget;
- Written explanation of variances, including that of the last Board approved year as compared to the actual expenditures for that year;

- Capitalization policy and any proposed changes to that policy; and
- For capital projects that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of cost of funds.

2.5.2.2 Asset Management Plan

- The applicant must provide a formal asset management plan, if the applicant has such a plan. If not, an explanation as to why the applicant does not have such a plan must be provided. The applicant must also state whether or not it is planning to have one in place in the future.
- In the absence of an asset management plan, the applicant must provide information outlining its approach to the planning and prioritization of capital projects.
- The applicant must also provide, at minimum, a three year forecast of capital expenditures (Test year plus two subsequent years).
- The applicant must also state whether or not it has undertaken any asset condition studies and, if so, copies of such studies must be filed.

2.5.2.3 Green Energy Act Plan Capital Expenditures

As discussed in Section 2.3.4, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a GEA Plan as part of such an application.

Any Capital Expenditures to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act and the Board's EB-2009-0397 Filing Requirements of March 25, 2010, should be outlined, including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers as per Regulation 330/09 and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349). This Report is discussed in more detail in Section 2.3.4.

A proposal seeking approval for a GEA plan should also clearly identify the period for which the utility is seeking prudence review and approval, and the utility's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.5.2.4 Harmonized Sales Tax ("HST")

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits ("ITCs"). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST. These cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

A utility should identify whether or not any adjustments have been made to capital expenditures and OM&A to reflect the implementation of the HST and if so, identify in supporting schedules and analyses the respective cost decreases and increases and how these were determined for all categories of costs.

Applicants should describe the steps taken in their budgeting processes to ensure that capital and OM&A costs contained in the application test year exclude all impacts of PST previously embedded in costs for the historical years submitted in evidence. Year-over-year cost comparisons should include a discussion of PST embedded in historical years' costs, and why cost increases for the test year are justifiable.

2.5.3 Service Quality and Reliability Performance

The applicant must provide the following information:

- Reported Electricity Service Quality Requirements ("ESQRs"), as set out in Chapter 7 of the *Distribution System Code*, for the last three historical years. In the event performance is below the established standard, the applicant must provide an explanation for the under-performance, as well as actions taken to address this matter, and any outcomes, as appropriate; and
- SAIDI, SAIFI and CAIDI, for the last three historical years. Reliability performance should be reported for the three indicators for: (1) All interruptions, and (2) All interruptions excluding Loss of Supply (Cause Code 2). In the event performance is outside of the established standard, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes, as applicable.

Reference documents for service quality and reliability indicators can be found at the following links:

Service Quality Indicators: Distribution System Code, Chapter 7
http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf
Reliability Indicators: Reporting and Record Keeping Requirements dated May 1, 2010 pages 9-12:
http://www.oeb.gov.on.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf

2.6 Exhibit 3. Operating Revenue

This exhibit includes evidence on the applicant's forecast of customers, energy and load, service revenue and other revenue, and variance analyses related to these items.

The applicant must provide its customer, volume and revenue forecast, weather normalization methodology, and other sources of revenue in this exhibit. The applicant must include a detailed description of the methodologies and the assumptions used. The information presented must include:

1) Load and Revenue Forecasts;
2) Variance Analyses; and
3) Other Revenue.

Estimates must be presented excluding commodity revenues.

2.6.1 Load and Revenue Forecasts

2.6.1.1 Overview

The applicant must provide an explanation of the causes, assumptions and adjustments for the volume forecast. All economic assumptions and data sources used in the preparation of the load and customer count forecast should be included in this section (e.g. Housing Outlook & Forecasts, relative energy prices and other variables used in forecasting volumes).

The applicant must also provide an explanation of the weather normalization methodology used and its application. The Board recognizes that an important aspect of any case is the uniqueness of the transmitter or distributor and the circumstances in which it operates. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather, and economies of each utility's market.

Two types of load forecasting models have generally been filed with the Board in previous cost of service applications. These are Multivariate Regression and Normalized Average Use per Customer ("NAC") models. While the applicant is not restricted to filing one of these two models, the following information is required for these two models when used. In the case where the applicant wishes to file a model other than the two noted above, the type of information that is required by the Board is provided below.

2.6.1.2 Multivariate Regression Model

- Rationale as to why the proposed model was chosen;

- Statistics of the regression equation(s) (coefficient estimates and associated t-statistics, and model statistics such as R^2, adjusted R^2, F-statistic, or Root-Mean-Squared-Error, etc.). Explanation for any resulting unintuitive relationships (e.g. negative correlation between load growth and economic growth, load growth and customer growth, etc.). An explanation of modeling approaches and alternative models tested must be provided;
- Explanation of the weather normalization methodology proposed including:
  - If the monthly Heating Degree Days ("HDD") and/or Cooling Degree Days ("CDD") are used to determine normal weather, the monthly HDD and CDD based on a) 10-year average and b) a trend based on 20-years;
  - In addition to the proposed Test year load forecast, the load forecasts based on a) 10-year average and b) 20-year trend HDD and CDD; and
  - Rationale as to why the proposed normal weather methodology was chosen.
- Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, complete explanation of the variable, data used and source should be provided.

2.6.1.3 Normalized Average Use per Customer ("NAC") Model

- Rationale as to why the proposed NAC methodology was chosen;
- Data supporting the calculation of NAC values used in the application for each rate class; and
- Discussion of weather normalization considerations.

2.6.1.4 General Requirements

- Information demonstrating the historical accuracy of the load forecast for at least the past 5 years;
- Schedule of volumes (in kWh and in kW for those rate classes that use this charge determinant), revenues, customer count by rate class and total system load in kWh) for:
  - Historical Actual for the past 5 years;
  - Historical Board Approved;
  - Historical Actual for the past 5 years – weather normalized;
  - Bridge Year;
  - Bridge Year – weather normalized; and
  - Test Year.

2.6.2 Variance Analyses

The applicant must provide the following variance analyses and relevant discussion:

- Historical Board-approved vs. Historical Actual;
- Historical Board-approved vs. Historical Actual – weather normalized;
- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual – weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

For each rate class, the applicant must provide the following information:

- Weather-normalized (if applicable) average historical actual consumption per customer for historical 5 years and forecasted average consumption for the Bridge Year and Test Year;
- For each rate class, an explanation of the net change in average consumption from last Board Approved and actual for Historical, Bridge Year and Test Year;
- Customer count increases or decreases forecasted for the Test Year with explanations of the forecast by rate class and identification as to whether customer count is shown in year-end or year average format;
- Details for the development of the billing kW value; and
- Revenues, provided on the basis of both existing and proposed rates.

All data used to determine the forecasts should be presented and filed in live MS Excel spreadsheet format.

2.6.3. Other Revenue

The applicant must provide the following information on Other Revenue:

- Breakdown of each of the other distribution revenue accounts (see Appendix 2-C for the required format);
- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years; and
- Any new proposed specific service charges, changes to rates or new rules for applying existing specific service charges.

Revenues or costs (including interest) associated with deferral and variance accounts should not be included in Other Revenue.

2.7 Exhibit 4. Operating Costs

This exhibit must include information that summarizes the Operating, Maintenance and Administrative ("OM&A") Costs and Taxes. The exhibit should include labour and compensation, whether expensed or capitalized, and depreciation expense.

This exhibit should include the following sections:

1. Manager's Summary;
2. Summary and Cost Driver Tables;
3. Variance Analyses;
4. Employee Compensation Breakdown;
5. Shared Services/Corporate Cost Allocation;
6. Purchases of Non-Affiliated Services;
7. Depreciation/Amortization/Depletion;
8. Taxes/PILs;
9. Green Energy Plan OM&A Costs, if applicable; and
10. Conservation and Demand Management ("CDM") Costs, if applicable.

The accounts listed in Appendix 2-D are to be included in the OM&A analyses.

2.7.1 Manager's Summary

The manager's summary should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A Test Year Levels;
- Associated cost drivers and significant changes that have occurred relative to historical and Bridge years;
- Overall trends in costs;
- Inflation rates used for general OM&A and Wages/Benefits. The Board has determined that the GDP-IPI is the most relevant inflation rate for utilities with respect to IRM rate applications, and the applicant should consider this in adopting an inflation rate. If the applicant proposes to use an inflation rate other than the GDP-IPI rate determined by the Board, appropriate justification should be provided (such as studies and/or sources);
- Staffing levels;
- Drivers for changes in salaries and wages and related costs;
- Business environment changes; and
- Materiality thresholds that apply.

2.7.2 Summary and Cost Driver Tables

The applicant must include the following tables as part of its evidence:

- Summary of OM&A Expenses (Appendix 2-E);
- Detailed Account by Account OM&A Expenses (Appendix 2-F);
- OM&A Cost Drivers (Appendix 2-G);
- Regulatory Costs (Appendix 2-H); and
- OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-I).

The applicant must note the specific requirements outlined below:

1. One-time costs;
2. Regulatory costs;
3. Low-income energy consumer programs (“LEAP”);
4. Special Purpose Charges related to the Green Energy Act;
5. Charitable donations; and
6. HST Impacts (See Section 2.5.2.4).

2.7.2.1 One-Time Costs

The applicant should identify one-time costs in the historical, bridge and test years and provide an explanation as to how the costs included in the test year are to be recovered.

2.7.2.2 Regulatory Costs

The applicant must provide a breakdown of the actual and anticipated regulatory costs, including OEB cost assessments and expenses for the current application such as legal fees, consultant fees, costs awards, etc. In addition, the applicant must identify how such costs are to be recovered, e.g., whether the costs are proposed to be amortized and over what period. The amortization period would normally be the duration of the expected cost of service plus IRM term (i.e. four years). If the applicant is proposing a different amortization period, it should explain why it believes this is appropriate.

2.7.2.3 Low-income Energy Assistance Programs (“LEAP”)

In March 2009, the Board issued its *Report of the Board: Low Income Energy Assistance Program* (the “LEAP Report”) which describes policies and measures for electricity and natural gas distributors to assist low-income energy consumers, including emergency financial assistance.

As set out in the LEAP Report, the Board has determined that the greater of 0.12% of a distributor’s Board-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance. The $2,000 minimum is intended to ensure that for smaller distributors more funding is available than otherwise would be if based solely on a percentage of distribution revenues. The LEAP amount should be calculated based on total distribution revenues, and is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

A distributor should include the relevant LEAP amount as part of its OM&A expenses. For greater clarity, Board-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the Board. If necessary, the LEAP amount proposed would be adjusted to account for any changes resulting from the Board's decision on the final service revenue requirement.

2.7.2.5 Charitable Donations

The applicant must file the amounts paid in charitable donations (per year) from the last Board approved rebasing application until (and including) the Test Year. The recovery of charitable donations will not be allowed for the purpose of setting rates, except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers. If the applicant wishes to recover such contributions, it must provide detailed information for those claims.

The applicant must review the amounts filed to ensure that all other non-recoverable contributions are identified, disclosed and removed. The applicant should also confirm that no political contributions have been included for recovery.

2.7.3 Variance Analyses

The applicant must provide variance analyses, both quantitative and qualitative, for the comparisons outlined in Appendix 2-J.

2.7.4 Employee Compensation Breakdown

The applicant must complete Appendix 2-K in relation to employee complement, compensation, and benefits. In addition to the information required per Appendix 2-K, the status of pension funding and all assumptions used in the analysis should be provided.

Where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related. This higher level of aggregation should be continued, if required, to ensure that no category contains three or fewer employees.

The applicant must provide details of employee benefit programs, including pensions and other costs charged to OM&A for the last Board-approved rebasing application, Historical, Bridge and Test Years. Post-retirement benefit cost accruals should be identified and described separately from current benefit costs. The most recent actuary report(s) should be included in the pre-filed evidence. What is disclosed in the tax section of the pre-filed evidence should agree with this analysis.

The applicant must provide:

- Explanations and justifications for year-over-year variances (include month hired for newly hired employees, inflation rates, collective agreement rates, etc);
- Basis for performance pay, goals, measures, and review processes for any pay-for-performance plans; and
- Any relevant studies conducted by or for the applicant (e.g., compensation benchmarking).

2.7.5 Shared Services/Corporate Cost Allocation

Shared Services is defined as the concentration of a company's resources performing like activities (typically spread across the organization) in order to service affiliates (and/or a parent company) with the intention of achieving lower costs and higher service levels.

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa). This is not to be confused with the allocation of the revenue requirement to rate classes for the purposes of rate design.

The applicant must provide the allocation methodology, a list of costs and allocators, and any 3rd party review of the corporate cost allocation methodology used.

The applicant must complete Appendix 2-L in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The table found in Appendix 2-L must be completed for each year. Additional rows may be added if required.

The table in Appendix 2-L requires the following information:

- *Type of Service Offered:*
  Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company allocated to the applicant.

- *Pricing Methodology:*
  Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant should also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- *Price for the Service:*
The applicant must provide the amount the entity pays for the service that it receives.

- *Cost for the Service:*
The applicant must provide the cost for the service.

- *% Allocation:*
The applicant must provide the percentage of the costs allocated to the entity for the service being offered.

Variance analyses, with explanations, are required for the following:

- Test Year vs. Last Board-approved Rebasing Application; and
- Test Year vs. Most Current Actuals.

The applicant must identify any Board of Director-related costs for affiliates that are included in its costs.

2.7.6 Purchase of Non-Affiliate Services

Utility expenses incurred through the purchase of services from non-affiliated firms must be documented and justified. An applicant should provide a copy of its procurement policy including information on such areas as the level of signing authority, a description of its competitive tendering process and confirmation that its non-affiliate services purchases are in compliance with it. For any such transactions above the materiality threshold that were procured without a competitive tender, or are not in compliance with the procurement policy, the applicant should provide an explanation as to why this was the case, as well as the following information for Historical (actuals):

- Summary of the nature of the product or service that is the subject of the transaction; and
- A description of the specific methodology used in determining the vendor (including a summary of the tendering process/cost approach, etc.).

2.7.7 Depreciation/Amortization/Depletion

The information outlined below is required for Depreciation/Amortization/Depletion:

- The applicant must provide details for Depreciation, Amortization and Depletion by asset group for the Historical, Bridge and Test Years, including asset amount and rate of depreciation or amortization. This should tie back to the accumulated depreciation balances in the continuity schedule under Rate Base. The applicant should identify any Asset Retirement Obligations ("AROs") and any associated

depreciation or accretion expenses in relation to the AROs, including the basis and calculation of how these amounts were derived.
- The applicant must provide a statement as to whether it adheres to the Board's guidelines on amortization/depreciation rates. If not, the applicant must summarize the differences, and indicate whether these have been previously reviewed and approved by the Board (and if so, to provide the relevant references).
- Where the applicant is proposing new or changed deprecation/amortization rates, supporting documentation justifying the selection of useful lives that differ from the typical useful lives identified by the Board's sponsored study must be provided.
- In particular, the Board's general policy for electricity distribution rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year. This is commonly referred to as the "half-year" rule. The applicant should identify its historical practice and its proposal for the test year. Variances from this "half-year" rule, such as calculating depreciation based on the month that an asset enters service, must be documented with supporting rationale.
- Where the applicant is proposing new or changed depreciation/amortization rates, supporting documentation, either a depreciation study or a statement that the new or changed rates are based on the depreciation study sponsored by the Board, must be provided.
- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant should provide a written description of the depreciation practices followed and used in preparing the application.

Appendix 2-M should be completed.

2.7.8 Taxes (Payments In Lieu of Taxes ("PILs"), Capital Tax and Property Taxes)

The applicant must provide the information outlined below:
- Detailed calculations of PILs (including a completed version of the PILs model available on the Board's web site), or Provincial and Federal taxes, as applicable, including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years. Note: Regulatory assets (and regulatory liabilities) should generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.
- Supporting schedules and calculations identifying reconciling items;
- Copies of most recent Federal and Provincial tax returns (non-utility tax items, if material, should be separated);
- Ontario Capital Tax for the historical years;
- Calculation of tax credits (e.g., apprenticeship training tax credits, education tax credits); and

- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.4.3).

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2.7.9 Green Energy Act Plan O&M Costs

As discussed in Section 2.3.4, Green Energy Act Requirements, distributors filing cost of service rate applications for 2012 and subsequent rate years must file with the Board a GEA Plan as part of such an application.

Any Operations and Maintenance costs to address Renewable Generation Connection or Smart Grid development as per the Green Energy Act and the Board's EB-2009-0397 Filing Requirements of March 25, 2010, should be outlined, including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers as per Regulation 330/09 and taking into account the Board's Report on the determination of direct benefits (EB-2009-0349). This Report is discussed in more detail in Section 2.3.4.

A proposal seeking approval for a GEA plan should also clearly identify the period for which the utility is seeking prudence review and approval, and the utility's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.7.10 Conservation and Demand Management ("CDM") Costs

The Board's *Conservation and Demand Management Code for Electricity Distributors* (the "CDM Code") was issued on September 16, 2010 and sets out obligations and requirements in relation to CDM activities after December 31, 2010. The CDM Code applies to CDM Programs that start on January 1, 2011 and end on December 31, 2014 or occur anytime in between those two dates. All electricity savings (kWh) and peak demand savings (kW) resulting from CDM Programs must also occur within that timeframe to be counted against a distributor's CDM Targets.

The Green Energy Act amended the OEB Act by including section 78.5 that discusses the manner in which payments will be made to distributors in respect to CDM Programs. Section 78.5 of the OEB Act now states that "the IESO shall make payments to a distributor or to the OPA on behalf of other persons prescribed by the regulations with respect to amounts approved by the Board for conservation and demand management programs approved by the Board pursuant to a directive issued under section 27.2. 2009, c. 12, Sched. D, s. 13." This is a change to the treatment of CDM related costs since historically Board-approved CDM programs were recovered through distribution rates.

The Board expects that most CDM funding for distributors going forward for the 2011-2014 period, will be provided by the OPA. It is expected that a distributor will enter into contracts to deliver OPA Province-Wide CDM Programs. If a distributor seeks to deliver a program(s) not being offered through the OPA Province-Wide Programs, it is able to apply for Board approval for a program(s) that is in compliance with the rules set out in the Board's CDM Code. This will be funded through the global adjustment mechanism, and therefore should not be included in distribution revenue requirements.

LRAM and SSM

As noted in the Board's CDM Guidelines (EB-2008-0037) unforecasted CDM results can have the effect of eroding distribution revenues due to lower than forecast throughput. The lost revenue adjustment mechanism ("LRAM") is a retrospective adjustment, which is designed to account for differences between the forecast revenue loss embedded in rates and the actual revenue loss.

While the LRAM removes the disincentive to deliver CDM Programs, a shareholder incentive, the shared savings mechanism ("SSM"), is also available to encourage distributors to pursue cost effective CDM programs. The SSM is available for CDM programs funded through distribution rates.

When calculating LRAM, the Board has stated in recent decisions that at the time of the third party review of CDM Programs, the most current OPA Measures and Assumptions lists, as updated by the OPA from time to time, represent the best estimate of losses associated with a distributor's CDM programs and should be used by distributors. The Board has also accepted finalized program evaluations delivered to distributors from the OPA in relation to OPA programs that the distributor has implemented as long as the distributor has included relevant documentation from the OPA in its application.

Deadline for filing LRAM and SSM applications

The Board has approved LRAM and SSM applications for many distributors since the beginning of the Third Tranche CDM period in 2005. The Board has stated its understanding that there may still be remaining distributors who have yet to apply to the Board for recovery of LRAM and/or SSM amounts related to CDM activities undertaken between 2005 and 2010.

Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the OPA between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.

2.8 Exhibit 5. Cost of Capital and Capital Structure

The Board's general guidelines for cost of capital in rate regulation are currently provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"), issued December 11, 2009. This report supersedes the previous *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "2006 Report") of December 20, 2006.

The 2009 Report states that cost of capital parameters will be based on data three full months prior to the effective date for new rates. The Board issues cost of capital parameter updates for cost of service applications for rates effective May 1 of the test year on an annual basis, normally around the beginning of March for use in that year's cost of service applications. The most recent data should be used as the default values in the 2012 rate applications, subject to an update when new parameters are available prior to the issuance of the Board's Decision for a specific distributor's application. For cost of service applications requesting a January 1 effective date, the Board will issue cost of capital parameters based on data for September of the previous year, in October or November.

If the applicant wishes to adopt the Board's guidelines for the cost of capital, the application should clearly state this and confirm that the cost of capital parameters will be updated in accordance with the Board's guidelines at the time of the Board's decision.

Alternatively, the applicant may apply for a utility-specific cost of capital and/or capital structure. If the applicant wishes to take such an approach, it must provide appropriate justification and supporting evidence for its proposal.

2.8.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the required schedules for current Board approved, Historical Actuals, Bridge and Test Years:

- Long-Term Debt;
- Short-Term Debt;
- Preference Shares; and
- Common Equity.

Appendix 2-N must be completed for the required years of all historical years, Bridge Year and Test Year.

Any explanations of changes in actual capital structure are required including:

- Retirements of debt or preference shares and buy-back of common shares; and
- Short-Term Debt, Long-Term Debt, preference shares and common share offerings.

2.8.2 Cost of Capital (Return on Equity and Cost of Debt)

These requirements are outlined in the 2009 Report. The applicant must provide the following information for each year:

- Calculation of the cost for each capital component;
- Profit or loss on redemption of debt and/or preference shares, if applicable;
- Copies of any current promissory notes or other debt arrangements with affiliates;
- Explanation of the applicable debt rate for each existing debt instrument, including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report;
- Forecasts of new debt anticipated in the bridge and test years, including estimates of the applicable rate and any pertinent information on each new debt instrument (e.g. whether the debt is affiliated or with a third party, expected term/maturity, any capital project(s) that the debt funding is for, etc.); and
- If the applicant is proposing any rate that is different from the Board guidelines, a justification of forecast costs by item, including key assumptions.

2.8.3 Not-for-Profit Corporations

In prior decisions, the Board has determined that applicants which are not-for-profit corporations may apply using the Board's deemed capital structure, cost of capital and working capital allowance to the extent that the excess revenue is to be used for the purpose of meeting the applicant's need to build up or accumulate appropriate operating and capital reserves. The Board has further stated that once the appropriate limits for these reserves have been achieved, it would expect such applicants to submit an application seeking a rate adjustment.

2.9 Exhibit 6. Calculation of Revenue Deficiency or Sufficiency

The applicant must include the following information in this exhibit, excluding energy costs and revenues:

- Determination of Net Utility Income;
- Statement of Rate Base;
- Actual Utility Return on Rate Base;

- Indicated Rate of Return;
- Requested Rate of Return;
- Deficiency or Sufficiency in Revenue; and
- Gross Deficiency or Sufficiency in Revenue.

The filing requirements have been designed in a manner to isolate the delivery-related deficiency/sufficiency separate and apart from the energy-related deficiency/sufficiency. In keeping with this separation, the applicant must provide revenue deficiency or sufficiency calculations net of electricity price differentials captured in the RSVAs and also net of any cost associated with LV charges or smart meter expenditures/revenues being tracked through variance accounts.

The applicant must provide a summary of the drivers of the test year deficiency/ sufficiency, along with how much each driver contributes. Specific references to the data contained in the detailed schedules and tables should be provided so that parties can map the summary cost driver information to the evidence supporting it.

The impacts of any change in methodologies should be provided on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.

The revenue requirement components in the application and the resulting revenue deficiency/sufficiency in this Exhibit should correspond with the calculations in the Revenue Requirement Work Form.

2.10 Exhibit 7. Cost Allocation

The following areas are discussed in this section:

1. Cost Allocation Study Requirements;
2. Revenue to Cost ratios; and
3. Class Revenues and Revenue-to-Cost Ratios

2.10.1 Cost Allocation Study Requirements

The Board expects that filings made by a distributor will follow the cost allocation policies outlined in the Board’s report of March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219).

A completed cost allocation study using the Board approved methodology must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. If available when this Exhibit is being prepared, the 2011 update of the model issued by the Board may be used.

If updated load profiles are not available, the load profiles of the classes may be the same as those provided by Hydro One for use in the Informational Filing, scaled to match the load forecast as it relates to the respective rate classes (see section 2.6.2 above). In particular, if a rate class has experienced a decline in customers or disappeared, or will disappear in the Test Year, the model must be consistent with the updated load forecast, and include an explanation of the changed load forecast of the rate class.

The Board recognizes that the applicant may not budget at the level of detail of the Uniform System of Accounts ("USoA"). However, to the extent possible, the applicant is required to summarize the forecast by USoA accounts into defined functionalized costs in the model, for the purposes of cost allocation and comparative analysis.

Distributors should refer to section 2.6.4 of the March 31, 2011 report concerning weighting factors for allocation of certain costs. A description of the weighting factors is required, including an explanation of why the distributor has chosen to use the default placeholders if applicable.

If using the Board approved model, the distributor should file a hard copy of input sheets I-6 and I-8, and output sheets O-1 and O-2. (Input sheet I.2, cells c-17 and d-17 should be used to identify the final run of the model on each sheet.) If using another model, the distributor should file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete Excel model electronically with the application.

Distributors should note the following:

- Large General Service and Large Use classes: The treatment of the Transformer Ownership Allowance has been revised in the updated version.

- Streetlighting: Experience has shown that the revenue requirement of the Streetlighting class is sensitive to inputs related to the number of connections (which determines the number of services) as distinct from the number of streetlighting fixtures (which determines the estimated coincident and non-coincident loads). Distributors are encouraged to use information that is as accurate as possible, and to stay apprised of progress in modeling in this area.

- Embedded Distributor: Any distributor that is the host to another distributor must include a customer class in the cost allocation model that appropriately captures the costs of serving the embedded distributors. This is required even if the distributor proposes to bill the embedded distributor using its General Service class rates.

- microFIT class: The Board does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2012, because it is not expected to have a material effect on outcomes. The cost allocation model will allocate costs and revenues without requiring data inputs from the distributor, and will also produce a calculation of unit costs to be used to update the uniform rate at a future date.

- New Customer Class: If the distributor is establishing a new customer class, the rationale for doing so is required, and information provided in the applicant's previous cost-of-service application concerning class revenue requirements should be restated in Appendix 2-O on the basis of the proposed customer classes to provide continuity with the proposed new customer class(es).

2.10.2 Class Revenue Requirements and Class Revenues

Appendix 2-O shows the format for filing cost allocation information and includes four tables.

The first table in Appendix 2-O is a format for showing the test year class revenue requirements, which is produced in output sheet O-1 of the Board model. This table also includes a comparison to the most recent study previously filed with the Board.

The Board has established ranges for revenue-to-cost ratios. Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. To support a proposal to re-balance rates, the distributor must provide information on the revenue by class that would pertain if all rates were changed by a uniform percentage. These ratios must be compared with the ratios that will result from the rates being proposed by the distributor.

The second table in Appendix 2-O shows three revenue scenarios, by rate class. Each scenario is based on the forecast of class billing quantities. The scenarios are, respectively, the forecast quantities multiplied by: a) existing rates, b) prorated existing rates that would yield the test year Base Revenue Requirement, and c) proposed class revenues. The table also shows the allocation of Miscellaneous Revenue to the rate classes, which is an output from the cost allocation model.

2.10.3 Revenue-to-Cost Ratios

The Board has established its policy with respect to how closely class revenues should be related to allocated costs. The policy is expressed in terms of revenue-to-cost ratios. The Board has updated the range of acceptable ratios in its March 31, 2011 Report, section 2.9.4. Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. The distributor should propose re-balancing to bring the revenue-to-cost ratio for one or more classes into the Board's policy range.

The third table in Appendix 2-O combines information from the previous two tables in the form of Revenue–to-Cost Ratios and includes the following information:

- The previously-approved ratios most recently implemented by the distributor;

- The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, together with the updated cost allocation model; and
- The ratios that are proposed for the Test Year, which are the proposed class revenues, together with the updated cost allocation model.

If the distributor proposes to continue re-balancing after the Test Year, the ratios proposed for the subsequent year(s) should be provided. The fourth table in Appendix 2-O provides a format. In particular, if the proposed ratios are outside the Board's policy range in the Test year, the distributor must show the proposed ratios in subsequent years that would move the ratios into the policy range.

If using a cost allocation model other than the Board model, the distributor must ensure that costs exclude LV costs, and Smart Meter costs being recording in accounts 1555 and 1556, and that revenues exclude rate riders and rate adders. The distributor should also ensure that information relevant to microFIT unit costs and revenue is consistent with the output from Board's model.

2.11 Exhibit 8. Rate Design

The following areas are discussed in this section:

1. Fixed/Variable Proportion
2. Retail Transmission Service Rates ("RTSR")
3. Retail Service Charges
4. Wholesale Market Service Charges
5. Specific Service Charges
6. Low Voltage Charges (where applicable)
7. Loss Adjustment Factors
8. Rate Schedules
9. Bill Impact Information
10. Mitigation Procedures (where applicable)

2.11.1 Fixed/Variable Proportion

The applicant must provide the following information related to the fixed/variable proportion of its proposed rates:

- Current fixed/variable proportion for each rate class, along with supporting information;
- Proposed fixed/variable proportion for each rate class, including an explanation for any changes from current proportions; and

- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study. The applicant must include an explanation if the monthly fixed charge for any customer class exceeds the ceiling.

The fixed/variable analysis should be net of (i.e., exclude) rate adders, funding adders and rate riders (i.e., Low Voltage, smart meters, GEA, deferral/variance account disposition, etc.).

2.11.2 Retail Transmission Service Rates (“RTSRs”)

In preparing its application, the distributor should reference the Board’s *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates (“UTRs”).

For 2012, distributors shall adjust their RTSRs based on a comparison of historical transmission costs adjusted for new UTR levels and revenues generated from existing RTSRs. This approach is expected to minimize variances in USoA Accounts 1584 and 1586. A filing module will be provided to distributors to assist in calculating the distributor’s class-specific RTSRs. The filing module will reflect the most recent Uniform Transmission Rates approved by the Board (EB-2010-0002), issued on January 18, 2011 and effective January 1, 2011. In the event that new Uniform Transmission Rates are approved during the course of a proceeding, the UTRs should be updated to reflect the new rates.

The distributor should ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.5.1.4, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.11.3 Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code (“RSC”). Distributors should note that the current retail service rates and charges were established on a generic basis. The Board expects applicants proposing changes to the level of the rates and charges or the introduction of new rates and charges, to provide evidence that they have consulted with retailers about the changes and have provided them with adequate notice of such changes.

Distributors should maintain the appropriate Retail Service 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.

2.11.4 Wholesale Market Service Rate

The Wholesale Market Service Rate is designed to allow distributors to recover costs charged by the Independent Electricity System Operator (“IESO”) for the operation of the IESO administered markets and the operation of the IESO-controlled grid.

The Wholesale Market Service Rate is an energy based rate (per kWh). This rate only applies to those customers of a distributor who are not wholesale market participants. An embedded distributor who is not a wholesale market participant would be treated as a customer to the host distributor and charged the same rate.

The Board has determined that this rate should be consistent across LDCs and, as such, changes to this rate would normally be made on a generic basis. Distributors wishing to apply for a change in this rate, outside of any changes that may be made to the generic rate, should provide justification as to why their specific circumstances would warrant such a change.

2.11.5 Specific Service Charges

The distributor should describe the purpose of each specific service charge for which it is seeking approval, unless the charge is one prescribed by the *Distribution System Code,* and ensure that this corresponds with the evidence under Operating Revenues (see section 2.6.3).

If the distributor is requesting either a new specific service charge or a change to the level of an existing charge, it should describe the purpose of the charge and provide calculations supporting the determination of the charge including the following elements:

- Direct labour (internal and/or external);
- Labour rate (internal and/or external);
- Burden rate;
- Incidental (e.g. postage for mail); and
- Vehicle time and rate (if applicable).

2.11.6 Low Voltage Service Rates (where applicable)

If the distributor is embedded (see section 2.4.1) the distributor must provide the following information:

- Forecast of LV cost, which is the sum of the host distributor’s charge for Common Sub-Transmission (i.e. ST) lines, and any other charges such as facility charges for connection to a shared distribution station;
- Support for the forecast of LV costs: forecast volumes and assumed host distributor’s LV rates;

- Allocation of forecast LV cost to customer classes (generally in proportion to Transmission Connection Rate revenues); and
- Proposed LV rates by customer class to reflect these costs.

Embedded distributors should complete Appendix 2-S.

2.11.7 Loss Adjustment Factors

The distributor must identify the proposed Supply Facilities Loss Factor (“SFLF”), distribution and total loss factors for the Test year.

The distributor must file the following information related to its proposed loss factors:

- A statement as to whether the applicant is embedded;
- Details of loss studies and recommendations, if required by a previous decision;
- Calculations showing the losses in previous years. Five years of historical data is preferred. A minimum filing of three years of data is required;
- Appendix 2-P showing the energy delivered to the distributor with and without losses;
- Explanation of distribution losses greater than 5%;
- Details of actions currently planned, and actions taken to reduce losses in previous five years and results if proposed distribution loss factor is greater than 5%; and
- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-P, Section H.

2.11.8 Revenue Reconciliation

The applicant must provide the current and proposed tariff of rates and charges. For the proposed tariff of rates and charges, the following information should be provided:

- Detailed calculations of revenue per rate class under current rates and proposed rates by customer class; and
- Detailed reconciliation of rate class revenue and other revenue to total revenue requirement (i.e., breakout volumes, rates and revenues by rate component, etc).

The applicant must provide an explanation of proposed changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates. The applicant should note that only rates shown on the Board-approved Tariff of Rates and Charges can be applied.

The applicant must provide a completed Appendix 2-U.

2.11.9 Bill Impacts

Appendix 2-V must be filed. This appendix identifies existing rate schedules, the revenue deficiency recovery, a summary of proposed changes to rates, proposed volume and revenue recovery, and detailed bill impacts (including % change in distribution, % change in delivery and % change in total bill).

The distributor should provide the impact of changes resulting from the as-filed application on representative samples of end-users, i.e., volume, percentage rate change and revenue. The distributor should include the base distribution rates, any applicable rate adders or rate riders, and RTSRs. Commodity rates and regulatory charges should be held constant.

The bill comparisons should be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. The applicant should also provide similar typical impacts for other classes, as well as any other comparisons the applicant may wish to provide for the residential and general service less than 50 kW classes. For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted, the applicant should show a typical comparison, and provide an explanation.

2.11.10 Mitigation Procedures (where applicable)

2.11.10.1 Mitigation Plan Approaches

The applicant must file a mitigation plan if total bill increases for any customer class exceed 10%. The mitigation plan should include the following information:

1. A specification of all customer classes or groups of customers that were initially identified as having increases in excess of 10% and the magnitude of these increases.

2. Any mitigation measures undertaken, e.g. reductions to the revenue requirement, inter- or intra-class shifts, and the resulting impacts.

3. A justification for all mitigation measures proposed.

4. A detailed description of all mitigation adjustments made.

5. Revised impact calculations.

6. Any other information the applicant believes is relevant.

The applicant should include the following bill comparisons based upon the proposed and the existing rates (including any Board-approved rate riders or adders):

- “Total” bill (including a commodity component and other rates);
- “Delivery charge” component of the customer’s bill (i.e. excluding the commodity component); and
- “Distribution charge” component of the customer’s bill (i.e. excluding the commodity component and other non-distribution rates).

The bill comparisons should be provided for typical customers and consumption levels (e.g., residential customers consuming 800 kWh per month, general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW, etc).

The bill comparisons should assume a constant commodity price and other rates, despite potential changes such as changes in the commodity price and other rates may not be known at the time of an application.

If a distributor determines in the course of the development of its mitigation plan that there is no suitable manner in which to resolve the bill increases exceeding the mitigation threshold, such a finding must be stipulated in the mitigation plan and supported with sufficient evidence.

The Board stated in its *2006 Electricity Distribution Rate Handbook Report of the Board* (RP-2004-0188), May 11, 2005 that, as a general rule, it did not favour mitigation plans dependent on imposing otherwise unwarranted increases on one customer class in order to reduce increases for another. The Board added that adjustments within a class of customers would be much more acceptable, such as changes to the fixed/variable splits which may have the effect of reducing bill impacts.

The Board also stated that mitigation plans that are predicated on reductions in the revenue requirement are problematic as revenue requirement reductions should incur to the benefit of all the distributor’s customers and form part of the basic rate application, not be a response to hardship cases. The Board expressed its concern that a distributor should not compromise its overall ability to deliver reliable service in order to address discrete instances of hardship.

The Board further stated that a distributor may choose to reduce its regulated rate of return in order to address situations requiring mitigation plans. However, the Board added that such a course of action should be prudently considered in light of the medium and long-term financial health of the organization and its ability to provide reliable service.

Mitigation policy is currently under review as one of the three policy initiatives which are part of the Board’s consultation on development of a renewed regulatory framework

(EB-2010-0378). In that light, there may be changes to the Board's mitigation policies going forward.

2.11.10.2 Rate Harmonization Mitigation Issues

Distributors which have merged or amalgamated service areas, and which have not yet fully harmonized the rates between or among the affected distribution service areas, may file a rate harmonization plan. The plan must include a detailed explanation and justification for the implementation plan and an impact analysis.

In the event that the combined impact of the cost of service based rate increases and harmonization effects result in total bill increases for any customer class exceeding 10%, the distributor should include a discussion of proposed measures to mitigate any such increases in its mitigation plan or provide a justification as to why a plan is not required.

A migration to fully harmonized rates that is to be accomplished over more than one year should be supported by a detailed plan for accomplishing this during the IRM period.

2.12 Exhibit 9. Deferral and Variance Accounts

The information outlined below is required regardless of whether or not the applicant is seeking disposition of any or all deferral and variance accounts:

- List of all outstanding deferral and variance accounts and sub-accounts. The applicant must provide a brief description of any account that the applicant may have used differently than as described in the Accounting Procedures Handbook;
- The continuity schedule for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances. Where appropriate, information should be shown separately by each sub-account (e.g. Account 1588, RSVA – Power, sub-account Global Adjustment, which is only applicable to non-RPP customers for recovery or refund), must be shown separately. A completed version of the continuity schedule available on the Board's web site must be filed;
- Interest rates applied to calculate the carrying charges for each regulatory deferral and variance account. The applicant must provide the rates by month or by quarter for each year;
- Explanation if the continuity schedule differs from the trial balance reported through the Electricity Reporting and Record-keeping Requirements and the Audited Financial Statements.
- Identification of which of the above accounts the applicant will continue on a going forward basis; and

- Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This should correspond with information provided in Exhibit 1 (see section 2.4.1).

2.12.1 Deferred PILs 1562 and 1592 Balances

The Board is conducting a separate combined proceeding, *Account 1562 – Deferred Payments in Lieu of Taxes, EB-2008-0381* (the "Combined Proceeding") to determine how and when deferred PILs 1562 balances should be disposed. The Board intends to consider the outcome of the Combined Proceeding to determine the appropriate method going forward to deal with the review and disposition of the balances in account 1562 for all remaining rate regulated electricity distributors. Distributors should not file applications for disposition of account 1562 balances until further instructions are received from the Board.

A settlement agreement filed in the Combined Proceeding was accepted by the Board in its Decision issued on December 23, 2010. The only aspect of the Settlement Agreement not accepted by the Board was a proposal to maintain the existence of account number 1562 after the Board approves final disposition, unless a distributor can demonstrate that any of its tax periods are not statute-barred.

The Board's Decision also stated that while the Settlement Agreement was not binding on any party but the parties to the Settlement Agreement, the Board intended, where appropriate, to apply such principles when considering applications from the remaining distributors not party to the proceeding.

Two of the settled issues in the Combined Proceeding relate to the tax impact of changes in regulatory asset (and regulatory liability) balances and the excess interest expense clawback. Parties agreed that regulatory assets (and regulatory liabilities) should be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts. Parties also agreed that the interest clawback adjustment has been part of the Board's methodology and must be retained. Both principles were upheld by the Board in its decision on Hydro One Brampton's 2011 cost of service application (EB-2010-0132).

Beginning in 2011, the Board has begun disposing of account 1592, PILs and Tax Variances for 2006 and Subsequent Years, on a final basis. The Board expects distributors to file for disposition of account 1592 in their cost of service applications. Distributors should complete and file Appendix 2-T in support of their request to dispose of account 1592.

2.12.2 Harmonized Sales Tax ("HST") Deferral Account

During the 2010 IRM application process, the Board directed electricity distributors to record in deferral account 1592 (PILs and Tax Variances, Sub-account HST/OVAT

Input Tax Credits ("ITCs")), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

In December 2010, as part of its Frequently Asked Questions on the Accounting Procedures Handbook for electricity distributors, the Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. Distributors filing for disposition of this sub-account in their cost of service applications should review this material.

No more amounts should be recorded in Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied-for revenue requirement (see section 2.5.2.4). For the 2012 Test Year for example, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to December 31, 2011 since the Test Year, which starts January 1, 2012 would include the HST impacts in rates going forward.

2.12.3 Special Purpose Charges ("SPC") related to the Green Energy Act

The Board authorized Account 1521, Special Purpose Charge Assessment Variance Account in accordance with Section 8 of Ontario Regulation 66/10 (*Assessments for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs*) (the "SPC Regulation"). Accordingly, any difference between (a) the amount remitted to the Minister of Finance for the distributor's SPC assessment; and (b) the amounts recovered from customers on account of the assessment must be recorded in "Sub-account 2010 SPC Assessment Variance" of Account 1521.

In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub-account 2010 SPC Assessment Variance.

The Board expects that requests for disposition of the balance in Sub-account 2010 SPC Assessment Variance and associated carrying charges will be addressed as part of the proceedings to set rates for the 2012 rate year. Exceptions may apply in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.

2.12.4 Disposition of Deferral and Variance Accounts

The applicant must:

- Identify all accounts for which it is seeking disposition;

- Identify any accounts for which the applicant is not proposing disposition and the reasons why;
- Propose rate riders for recovery or refund of balances that are proposed for disposition. The default disposition period is one year, or if the applicant is proposing an alternative period, an explanation should be provided;
- Indicate if the balances proposed for disposition before forecasted interest match the last Audited Financial Statements;
- Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period; and
- Establish separate rate riders to recover the RSVA Power, Sub-account Global Adjustment from non-RPP customers.

2.12.5 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant should refer to *Guideline G-2008-0002: Smart Meter Funding and Cost Recovery*, or any successor document issued by the Board, with respect to any proposal to dispose, or partially dispose balances in accounts 1555 and 1556. In support of such proposals, the applicant must provide a continuity schedule of the sub-account balances in accounts 1555 and 1556 and complete the table contained in Appendix 2-Q. Distributors should note that Appendix 2-Q will be revised in conjunction with a pending update to Guideline G-2008-0002. Distributors filing in advance of the update must file the current Appendix 2-R.

For those distributors that were subject to an IRM based rate adjustment for their 2011 rates, the Board approved the continuation of any Smart Meter Funding Adder ("SMFA") to be in effect until no later than April 30, 2012. The Board stated that distributors would be expected to file for a final prudence review of the costs in the smart meter variance accounts at the earliest possible opportunity following the availability of audited costs, since the deployment of smart meters on a province-wide basis is now nearing completion. Distributors scheduled to file 2012 cost of service applications would be expected to apply for the disposition of smart meter costs, subsequent inclusion in rate base, and for recovery of stranded costs, in that application.

As part of the 2011 IRM rate proceedings, the Board did not make any finding on the prudence of any costs associated with proposed smart meter activities, including costs for smart meters or advanced metering infrastructure whose functionality exceeded the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs were to be considered when a distributor applied for their recovery on a final basis as part of a cost of service based application.