Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2006-0170

Ontario Energy Board

Filing Requirements For Electricity Transmission and Distribution Applications

Last Revised on June 28, 2012
(Originally issued on November 14, 2006)

Table of Contents

Ontario Energy Board

Commission de l'énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

Ontario Energy Board

Chapter 1 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

Chapter 1 - Overview

This document provides information about the filing requirements for electricity transmission and distribution applications. It is designed to provide direction to applicants, and it is expected that applicants will comply with the filing requirements unless such compliance is not practical or in the public's interest. It is not a statutory regulation or a rule or code issued under the Board's authority. It does not preempt the Board's discretion to make any order or directive as it determines necessary concerning any of the matters raised by the applications filed.

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 in Chapter 2, are only applicable to distributors. These sections will use the word "distributor" when referring to the filer.

The purpose of this document is to provide information about several filing requirements dealing with electricity transmission and distribution applications. These include:

Chapter 2 - Filing requirements for electricity transmission and distribution companies' cost of service rate applications pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "Act"), based on a forward test year;

Chapter 3 - Filing requirements for the 3rd generation incentive regulation mechanism for electricity distributors pursuant to section 78 of the Act;

Chapter 4 - Filing requirements for leave to construct electricity transmission projects under section 92 of the Act;

Chapter 5 - Vacant;

Chapter 6 – Vacant; and

Chapter 7 - Filing requirements for applications for service area amendments under section 74(1) of the Act.

Chapter 2 details the filing requirements for a cost of service rate application based on a forward test year that the Board will require from an electricity transmission or distribution company. They set out the necessary material that should be included in a rate application. An application that fails to provide all of the elements may be considered incomplete and may not be processed until the material is provided.

Chapter 3 details the filing requirements under the incentive regulation mechanism. This approach will be used for electricity distributors when there is no requirement to file a cost of service rate application.

Chapter 4 details the filing requirements for the approval of leave to construct electricity transmission projects under section 92 of the Act for the construction, expansion, or reinforcement of electricity transmission facilities greater than 2 km in length.

Chapter 5 formerly contained filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the Act prior to the approval of an Integrated Power System Plan. Any requirements that remain applicable have been included in the recent update to Chapter 4. Chapter 5 is now vacant.

Chapter 6 formerly contained filing requirements on conservation and demand management ("CDM"). These have been superseded by the CDM Code, and the April 26, 2012 CDM Guidelines issued under EB-2012-0003. Chapter 6 is currently vacant.

Chapter 7 contains the filing requirements for service area amendment applications under section 74 (1) of the Act, which were last issued on March 12, 2007.

Completeness and accuracy of an application

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 proposals are just and reasonable. The material presented is the applicant's evidence and the onus is on the applicant to prove, for example, the need for and reasonableness of the costs that are the basis of proposed new rates (Chapter 2). 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 same holds true for any other requests that form the basis of an application pursuant to other chapters of these filing requirements. The applicant must, at a minimum, meet all of the applicable filing requirements. However, the applicant has the responsibility to file additional material where necessary to prove its case.

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 entire record, participate meaningfully in the proceeding and understand the reasons for a decision. Consequently, a complete and accurate evidentiary record is vital.

The purpose of the interrogatory process is to test the evidence before the Board, and not to seek information that should have been provided in the original application. The Board will consider an application complete if it meets <u>all</u> of the applicable filing requirements. Applicants must also be cognizant of the need for accuracy and consistency of the information or data presented in their applications. Applicants must ensure that information and data is consistent across all exhibits, appendices and models. If an application does not meet <u>all</u> of these requirements or if there are inconsistencies identified in the information or data presented, 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.

Certification of Evidence

Each application shall include a certification from a senior officer of the applicant that the evidence filed is accurate to the best of his/her knowledge or belief.

Updating an Application

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.

Interrogatories

The Board is aware of the 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 an application. The Board advises applicants to strategically consider the clarity of the evidence, to reduce the need for interrogatories. The Board also advises parties to carefully consider the relevance and materiality of information before requesting it through an interrogatory

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 arising from an application under Chapter 2, 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.

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* (the "Practice Direction") 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 address the issue and permit the Board to provide meaningful and well-documented reasons for its decision.

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. If confidential treatment is requested in relation to the entire document, the document should be printed on coloured paper; 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, whether the information is being filed as part of an application or in response to an interrogatory. An illustrative list of the types of information that the Board has previously assessed or maintained as confidential is set out in Appendix B of the Practice Direction.

Parties should also take note of the requirements related to relevance of interrogatories outlined in this chapter, which are also applicable to information which is requested and raises confidentiality concerns. Parties should give particular significance to the relevance of interrogatories in relation to confidential filings given the administrative issues associated with the management of those filings.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

Ontario Energy Board

Chapter 2 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

Table of Contents

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 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 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-P 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 chapter 4 of the Filing Requirements (see Section 2.5 dealing with capital budgets for projects with construction commencing in the Test Year).

Applicants should review Chapter 1 of this document which provides an overview of the various chapters in this document and addresses the Board's expectations on certain generic matters such as the completeness and accuracy of an application and confidential filings.

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 and one such application for the 2012 year. It is recommended that distributors contemplating an early rebasing application for 2013 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-X.

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.

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;
- *Guideline G-2011-0001:Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011, 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-2012-0003), April 26, 2012;
- *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates*, October 22, 2008 and any subsequent updates;
- *Asset 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);

- Board letter of April 12, 2012, providing an update on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year; and
- Board letter of April 30, 2012, providing guidance to electricity distributors on the impact of the decision to defer the mandatory date for the implementation of IFRS.

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); and
  - 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 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;
- Documents are to be provided in a text-searchable Adobe PDF format; and
- Tables should also be provided in Excel spreadsheet format.

2.3.3 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 May 17, 2012 update to the *Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence* (EB-2009-0397).

As permitted by Section 2.2 of the May 17, 2012 update to the EB-2009-0397 Filing Requirements, the Board may permit a utility to defer the filing of a GEA plan. A utility that wishes to request a deferral should specifically include that request in its cost of service application, together with a detailed explanation of why the deferral has been requested, and a proposal for when the GEA plan will be filed.

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 2013 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 ("CDM 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.

- *Guidelines for Electricity Distributor Conservation and Demand Management ("CDM Guidelines")* *(EB-2012-0003)*

  The CDM Guidelines provide specific guidance on certain provisions in the CDM Code and identify the evidence that should be filed by distributors in support of an application for Board-Approved CDM programs. In addition, the CDM Guidelines provide details on the Lost Revenue Adjustment Mechanism related to CDM programs implemented under the CDM Code and for persisting lost revenues for pre-2011 CDM programs.

- *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).

2.3.4 Transition to International Financial Reporting Standards ("IFRS"), United States Generally Accepted Accounting Principles ("USGAAP"), or an Alternate Accounting Standard

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

- Impact of the Decision to Defer the Mandatory Date for the Implementation of IFRS to January 1, 2013 by the Canadian Accounting Standards Board, Board letter dated April 30, 2012;
- *Report of the Board: Transition to IFRS;* dated July 28, 2009;
- *Addendum to Report of the Board: Implementing IFRS in an Incentive Rate Mechanism Environment (*the "Addendum"), dated June 13, 2011.

- *Asset Depreciation Study for the Ontario Energy Board*, Kinectrics Inc. for distributors sponsored by the Board dated July 8, 2010; and
- Clarification letter regarding accounting for overhead costs associated with capital work, dated February 24, 2010.

For those applicants that must adopt IFRS for financial reporting purposes by January 1, 2013, 2013 cost of service applications must be filed on the basis of Modified IFRS ("MIFRS").

For those applicants that adopted IFRS on January 1, 2012 for financial reporting purposes, the date of transition is January 1, 2011. For those applicants that adopted IFRS on January 1, 2013 for financial reporting purposes, the date of transition is January 1, 2012.

Per the Board's letter of April 30, 2012, 2013 cost of service application are to be filed on the basis of MIFRS, except for those seeking the Board's approval to adopt USGAAP or Accounting Standards for Private Enterprise ("ASPE") as addressed by the Addendum. For MIFRS applications, the applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS accounting.

Applicants should provide the following information:

- If an applicant chooses to adopt IFRS for financial reporting in 2012, in its 2013 cost of service application it must file information for the year prior (i.e., 2011 - the historic year) in both CGAAP and modified IFRS format, and provide the bridge year (2012) and the forecasts for the test year (2013) information in modified IFRS. The years required to be filed prior to the historic year 2011 may be provided in CGAAP only.

- If an applicant chooses to adopt IFRS for financial reporting in 2013, in its 2013 cost of service application it must provide the required actual years (2011) and the bridge year (2012) in CGAAP based format. An applicant must present modified IFRS based forecasts for the bridge (2012) and test years (2013).

The Board requires a utility that adopts USGAAP or an accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to provide the following:

1. evidence of the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
2. a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable); and

3. evidence demonstrating the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its accounting policies made since the applicant's last cost of service filing (e.g. capitalization of overhead, capitalization of interest, depreciation, etc.). Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.

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;
- Statement as to when the distributor believes the Board's rate order would be required in order to achieve rate implementation by the requested date;
- 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 and rationale for organizational change and estimated cost impact;
    - 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);
- Identification of accounting standard for financial reporting purposes under which the applicant has filed its rate application, IFRS, USGAAP, etc;
- 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;
- Schedule providing the most recent Board-approved revenue requirement and breakdown (i.e. OM&A, depreciation, taxes or PILs (grossed up), return and revenue offsets); and
- Revenue Requirement Work Form. The link on the Board's website may be used to access this work form provided in Microsoft Excel format.

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, in both the application material and in working Microsoft Excel format.

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;
- 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;

For an applicant that adopted IFRS on January 1, 2012 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2010 regulatory gross assets of property, plant and equipment as the opening January 1, 2011 regulatory gross assets. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2010 regulatory gross assets of property, plant and equipment, by asset class; and
- January 1, 2011 regulatory gross assets of property, plant and equipment, by asset class.

For an applicant that adopts IFRS on January 1, 2013 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2011 regulatory gross assets of property, plant and equipment as the opening January 1, 2012 regulatory gross assets. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2011 regulatory gross assets of property, plant and equipment, by asset class; and
- January 1, 2012 regulatory gross assets of property, plant and equipment, by asset class.

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.

For an applicant that adopted IFRS on January 1, 2012 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2010 regulatory accumulated depreciation as the opening January 1, 2011 regulatory accumulated depreciation. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2010 regulatory accumulated depreciation, by asset class; and
- January 1, 2011 regulatory accumulated depreciation, by asset class.

For an applicant that adopted IFRS on January 1, 2013 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2011 regulatory accumulated depreciation as the opening January 1, 2012 regulatory accumulated depreciation. The applicant must provide schedules (including Appendix 2-B, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2011 regulatory accumulated depreciation, by asset class; and
- January 1, 2012 regulatory accumulated depreciation, by asset class.

2.5.1.4 Allowance for Working Capital

In a letter dated April 12, 2012, the Board provided an update to electricity distributors and transmitters on the options established in the June 22, 2011 cost of service filing requirements for the calculation of the allowance for working capital for the 2013 rate year. The applicant may take one of two approaches for the calculation of its allowance for working capital: (1) the 13% 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:

- **13% Allowance Approach**

  The 13% Allowance Approach is calculated to be 13% 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 and uses the most current RPP price. The calculation should also reflect the most recent Uniform Transmission Rates approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. Generally, if new information becomes available for Uniform Transmission Rates and RPP during the course of a proceeding, the Cost of Power would be updated to reflect the new rates.

- **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.

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) provided 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, distributors should have 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.

On December 15, 2011, the Board issued *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition*. Section 3.7 and Appendix A-1 provide the most current guidance on the treatment for recovery of costs for stranded meters replaced by smart meters.

Distributors should file as part of their 2013 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, 2012, or a revised amount calculated in accordance with the above-noted accounting guidance, should be removed from rate base (see Appendix 2-S). The 2013 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 or does not expect to complete 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, 2012 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. Appendix 2-A must be filed.

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, load 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 commencing in the test year, the applicant must provide a summary of the evidence for that project consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular);
- Components of Other Capital Expenditures, including a reconciliation of all capital components to the Total Capital Budget;
- Written explanation of variances, including that of actuals versus the Board-approved amounts for the applicant's last Board-approved cost of service application;
- 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 the cost of funds.

2.5.2.2 Capitalization Policy

The applicant must provide its capitalization policy, including changes to that policy since the last rebasing application filed with the Board.

Applicants that must adopt IFRS for financial reporting purposes by January 1, 2013, must adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.

If the applicant has changed its capitalization policy since the last rebasing application, regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must explain the reason for these changes and whether they are a result of adhering to the IFRS capitalization accounting requirements. The changes must be identified, (e.g. capitalization of indirect costs, etc.) and the causes of the changes must also be identified.

2.5.2.3 Capitalization of Overhead

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Burden Rates

The applicant must identify the burden rates related to the capitalization of costs of self-constructed assets. Furthermore, if the burden rates were changed since the last rebasing application, the applicant must identify the burden rates:

- Prior to the change
- After the change

2.5.2.4 Asset Management Plan

- The applicant must provide an asset management plan, if available. .
- If not, an explanation as to why the applicant does not have such a plan must be provided and the applicant must provide information outlining its approach to the planning and prioritization of capital projects. The applicant must also state whether or not it will develop and implement such a plan in the future.
- The applicant must also provide, at a 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.

2.5.2.5 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 per the *Green Energy Act* and the Board's EB-2009-0397 Filing Requirements update of May 17, 2012 should be documented, including a proposal, where applicable, to divide the costs of eligible renewable generation connection investments between the applicant's ratepayers and all Ontario ratepayers 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 review and approval of any proposed costs, and the utility's proposal for how approved GEA plan costs are to be recovered (e.g., rate adder, rate rider, deferral/variance account).

2.5.2.6 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).

An applicant must 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, the applicant must identify in supporting schedules and analyses the respective cost decreases and increases and how these were determined for all categories of costs.

Applicants must 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 must 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 (if available). .

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.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf
> Reliability Indicators: Reporting and Record Keeping Requirements dated March 7, 2012 pages 9-12:
> http://www.ontarioenergyboard.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. 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.

The applicant must include in the test year forecast any impacts arising from the persistence of historical conservation and demand management programs, as well as the forecast impacts arising from new programs deployed in the bridge and test years. This CDM component of the forecast must be specifically identified by class, as the amount approved by the Board will be the basis for the lost revenue adjustment mechanism variance account ("LRAMVA").

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.

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.
- Description of how conservation and demand management ("CDM") impacts have been accounted for in the historical period, and how CDM, including the CDM targets that are a condition of a distributor's licence, is factored into the Test year load forecast; and

- 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
- Description of how conservation and demand management ("CDM") impacts have been accounted for in the historical period, and how CDM, including the CDM targets that are a condition of a distributor's licence, is factored into the Test year load forecast; 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 for applicable classes; 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-F for the required format);
- Comparison of actual revenues for historical years to forecast revenue for Bridge and Test Years, including explanations for significant variances in year-over-year comparisons;
- Any new proposed specific service charges, changes to rates or new rules for applying existing specific service charges; and
- Any revenue from affiliate transactions, shared services or corporate cost allocations as described in section 2.7.5

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-G 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 Recoverable OM&A Expenses (Appendix 2-I);
- Detailed Account by Account OM&A Expenses (Appendix 2-G);
- OM&A Cost Drivers (Appendix 2-J);
- Regulatory Costs (Appendix 2-M); and
- OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-L).

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, or an alternate accounting standard, the applicant must identify the overall level of increase *(or decrease)* in OM&A expense in the test year in relation to a decrease *(or increase)* in capitalized overhead. The applicant must provide a variance analysis for the change in OM&A expense for the test year in respect to each of the bridge year and historical years. The applicant must complete Appendix 2-D.

The applicant must note the specific requirements outlined below:

1. One-time costs;
2. Regulatory costs;
3. Low-income energy assistance programs ("LEAP");
4. Special Purpose Charges related to the Green Energy Act;
5. Charitable donations; and
6. HST Impacts (See Section 2.5.2.6).

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. The applicant must provide information supporting the level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify how such costs are to be recovered (i.e., 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 from the revenue requirement calculation. 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-H.

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 year and 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 and Corporate Cost Allocation

Shared Services is defined as the concentration of a company's resources performing 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-N in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The table found in Appendix 2-N must be completed for each year. Additional rows may be added if required.

The table in Appendix 2-N 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. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

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 must 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.
- 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 must 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.

- 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. Regardless of the accounting standard used in the application, the applicant must provide a summary of changes to its depreciation/amortization policy made since the applicant's last cost of service filing.
- The applicant must ensure that the significant parts or components of each item of PP&E are being depreciated separately. The applicant must explain if it departs from this practice.
- For an applicant that files a 2013 cost of service application on the basis of MIFRS or adheres to IFRS requirements with respect to depreciation and capitalization:
    - The applicant must use the Board sponsored Kinectrics study or provide its own study to justify changes in useful lives.
    - The applicant must provide a list detailing all asset service lives. The applicant must detail differences of its asset service lives from the Typical Useful Lives (TUL) from the Kinectrics Report and provide a detailed explanation for using a service life that is different from the TUL in the Kinectrics Report.
    - Applicants must perform a recalculation to determine the average remaining life of the opening balance of assets on the transition date to IFRS (i.e. excluding the transition year capital additions).
    - If an applicant chooses to adopt IFRS for financing reporting in 2012, the applicant must complete Appendix 2-CA to Appendix 2-CD (inclusive).
    - If an applicant chooses to adopt IFRS for financial reporting in 2013, the applicant must complete Appendix 2-CE to Appendix 2-CH (inclusive).

If the applicant has adopted an accounting standard other than IFRS, the applicant must specify the details if it adopted, in part or in full, TUL estimates that were used in the Board sponsored Kinectrics study or its own asset service life studies and determine the impacts. The applicant must provide a detailed justification for any changes in service lives. Applicants that filed a rate application under an alternate accounting standard other than IFRS must complete Appendix 2-CI.

2.7.8 Taxes or Payments In Lieu of Taxes ("PILs") 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);
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.4.3).
- The federal and Ontario Notice of Assessments, Notice of Re-assessments (if applicable), Statements of Adjustments, and any other correspondence with the CRA and Ontario Ministry of Finance regarding any tax items, or tax filing positions that may be in dispute, or under consideration or review, for the three immediately prior tax years.
- A calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits). SRED return, if filed, may have confidential personal information of the people who are apprenticing like SIN, address, hourly rate, etc. which should be excluded from the filing; and
- Supporting schedules, calculations and explanations for “other additions” and “other deductions” in the applicant’s PILs model.

2.7.8.1 Non-recoverable and Disallowed Expenses

There may be some distribution-only expenses incurred by a distributor that are deductible for general tax purposes, but for which recovery in 2013 distribution rates is partially or fully disallowed.

Where an expense incurred by a distributor is non-recoverable in the revenue requirement (e.g. certain charitable donations) or disallowed for regulatory purposes, such amounts will also be excluded from the regulatory tax calculation.

2.7.8.2 Integrity Checks

The applicant must ensure the following integrity checks have been achieved in its application:

- The depreciation and amortization added back in the application’s PILs model agree with the numbers disclosed in the rate base section of the application.
- The capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historic, bridge and test years.
- Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge

year UCC at January 1st. If the amounts do not agree, then the applicant must provide a reconciliation with explanations for the reasons.

- The CCA deductions in the application's PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application.
- Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application.
- CCA is maximized even if there are tax loss carry-forwards.
- A statement is included in the application as to when the losses, if any, will be fully utilized.
- Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation. The amounts deducted must be reasonable when compared with the notes in the audited financial statements, FSCO reports, and the actuarial valuations; and
- The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.

2.7.9 *Green Energy Act* Plan O&M Costs

As discussed in Section 2.3.3, 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 as updated on May 17, 2012, 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 2.3.3.

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 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 Board expects that, going forward, most CDM funding for distributors for the 2012-2014 period, will be provided by the Ontario Power Authority (“OPA”). It is expected that a distributor will enter into contracts to deliver OPA-Contracted Province-Wide CDM Programs. If a distributor seeks to deliver programs not being offered through the OPA-Contracted Province-Wide Programs, it is able to apply for Board approval for programs that are in compliance with the rules set out in the Board’s CDM Code and clarified in the April 26, 2012 Conservation and Demand Management Guidelines (EB-2012-0003) (CDM Guidelines). This will be funded through the global adjustment mechanism, and therefore should not be included in distribution rates.

Lost Revenue Adjustment Mechanism

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.

On April 26, 2012, the Board issued updated CDM Guidelines. The CDM Guidelines were developed to provide more clarity on the CDM Code and what information needs to be filed in support of Board-Approved CDM program applications, as well as to provide updated details on the LRAM and the associated variance account for the 2011-2014 term.

LRAM Variance Account (“LRAMVA”) for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the Board-approved forecasted CDM related load forecast reduction to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- For Board-approved programs, a third party report, in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested; and
- For OPA Contracted Province-Wide Programs the distributor must provide documentation (i.e. final evaluation report from the OPA) of the distributor's results.

A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.

LRAM and/or SSM for pre-2011 CDM activities

In Section 3.4.2 of Chapter 3 of the Filing Requirements, issued June 22, 2011, the Board stated that 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 the legacy period of CDM activity (2005 – 2010).

The Board expects LRAM claims for pre-2011 CDM activities to have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. SSM is not applicable for savings persisting from the legacy period.

In support of its application for persisting lost revenues from pre-2011 CDM programs, distributors must file the following:

- A statement confirming that the distributor's load forecast has not been updated as part of a cost of service application since the CDM programs, for which persistent lost revenue is sought, were implemented;
- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- A third party report that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculation
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested.

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 (Appendices 2-OA and 2-OB) for current Board approved, Historical Actuals, Bridge and Test Years:

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

Appendix 2-OB 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 (i.e. cost of power and associated costs) 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 and for which disposition is not being sought in the application.

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. The 2011 update of the model issued by the Board will be available on the Board's web site.

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.

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 (first page only). 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 Class: Any distributor that is the host to one or more distributors must provide information on the cost of serving those embedded distributors in one of two ways. If the host has a separate rate class for embedded distributor(s) or is proposing such a class, the host distributor must include the class as such in its cost allocation study and in Appendix 2-P. If the host distributor proposes to bill the embedded distributor(s) as if it/they were General Class customers, the costs and revenue should be included with that class in the cost allocation study and Appendix 2-P and the host distributor must also complete Appendix 2-Q which shows details on how much of the host's facilities are required to serve the embedded distributor(s).

- microFIT class: The Board does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2013, 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-P 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-P shows the format for filing cost allocation information and includes four tables.

The first table in Appendix 2-P 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-P 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-P combines information from the previous two tables in the form of Revenue–to-Cost Ratios and includes the following information for each class:

- 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, expressed as a ratio with the class revenue requirements derived in 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-P provides a format for presentation. 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 the 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 ("RTSRs")
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)

Please note that monthly fixed charges should be shown to two decimal places while variable charges should be shown to four places. Distributors wishing to depart from this approach should provide a full explanation as to why they believe it is necessary**.**

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"). A filing module will be provided to distributors to assist in calculating the distributor's class-specific RTSRs.

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 charges to the applicant.
- Support for the forecast of LV costs: forecast volumes and actual or forecast host distributor's LV rates. For example, a distributor whose host distributor is Hydro One would list ST lines, plus an ST Service Charge, plus any other charges such as facility charges for connection to a shared distribution station that apply to the embedded applicant's monthly bill from the host distributor, together with the applicable charge determinants.
- 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.

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-R 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-R, 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-V.

2.11.9 Bill Impacts

Appendix 2-W must be filed for all classes. 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 distribution excluding pass-through costs, % 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 (as 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). Where the consumption patterns of a utility's typical customers vary markedly from these norms, the applicant should explain the customer profile(s) that it wishes to use, as an additional calculation.

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 for electricity (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 APH;
- 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 in working Microsoft Excel format;
- 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).
- A statement as to whether the applicant has made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in both cost of service and IRM proceedings (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). If this is the case, the applicant must provide explanations for the nature and amounts of the adjustments and include supporting documentation.
- A breakdown of energy sales and cost of power expense, as reported in the audited financial statements, by USoA account number. The applicant must tie these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, the applicant must explain why it is making a profit or loss on the commodity.

- A statement confirming that the applicant pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, the applicant must provide an explanation.

2.12.1 PILs and Tax Variances for 2006 and Subsequent Years - Account 1592

Beginning in 2011, the Board began 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. Applicants 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 2013 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, 2012 since the Test Year, which starts January 1, 2013 would include the HST impacts in rates going forward. If the Test Year's rate year begins May 1, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2013.

The applicant must provide an analysis that supports the applicant's conformity with December 2010 APH FAQs, in particular the example shown in FAQ #4.

The applicant must state whether entries have been made to record variances in the sub-account of Account 1592 to cover the period from July 1, 2010 to December 31, 2012 since the Test Year, which starts January 1, 2013 would include the HST impacts in rates going forward. If this is not the case, please explain. If the rate year begins May

1, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2013.

2.12.3 One-time Incremental IFRS Costs

For an applicant that files a 2013 cost of service application on the basis of MIFRS and is seeking recovery of one-time administrative incremental IFRS transition costs, or has such costs already reflected in base rates:

- Applicants that have one-time administrative incremental IFRS transition costs already included for recovery in its rates, must file for disposition of the balance in Account 1508, Other Regulatory Assets, "Sub-account IFRS Transition Costs Variance" reflecting the difference between the amounts recovered in rates and the actual incurred one-time administrative incremental IFRS transition costs.

- The applicant must provide a breakdown of the costs recorded in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance. The applicant must complete Appendix 2-U.

- The applicant must provide explanations for each category of costs recorded in the Deferred IFRS Transition Costs Account or IFRS Transition Costs Variance Account. The applicant must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

- The applicant must provide explanations for material variances that may exist in the IFRS Transition Costs Variance account.

- Per the October 2009 APH FAQ #3 regarding costs that are permitted to be recorded in the Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account, the applicant must provide a confirmation statement that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy changes are recorded in the Deferred IFRS Transition Costs Account or IFRS Transition Costs Variance Account. If this is not the case, the applicant must provide an explanation.

2.12.4 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

The applicant must propose a disposition period to "clear" the PP&E deferral account through a one-time adjustment to rate base to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS. The Board will determine the period of time for amortization on a case-by-case basis. The Board will be guided primarily by such considerations as the impact on rates, implications of any other IFRS transition matters, any requirements for rate mitigation including the impact on the distributor's customers and its cash flow position, and other matters such as intergenerational equity. No carrying charges will be applied to the balance in the PP&E account.

For an applicant that files a 2013 cost of service application on the basis of MIFRS:

- The applicant must provide evidence that indicates the IFRS-CGAAP Transitional PP&E Amount is to be cleared in rates as follows:
  - an adjustment to the test year depreciation expense (Appendix 2-CD or Appendix 2-CH, 2013 MIFRS Depreciation Expense) as part of distribution expenses for the amortization of Account 1575, and
  - an adjustment to the test year revenue requirement as part of the return on rate base component. The applicant must not record the return on rate base component in Account 1575 for accounting purposes.
- The Fixed Asset Continuity Schedule (Appendix 2-B) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount.
- The applicant must provide a breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to MIFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EA or 2-EB. The drivers of the change in closing net PP&E (CGAAP versus MIFRS) must be identified and quantified.

2.12.5 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; if the applicant is proposing an alternative recovery period, an explanation should be provided;
- Indicate if the balances proposed for disposition before forecasted interest match the last Audited Financial Statements and provide explanations for any variances;
- 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 Account Global Adjustment from non-RPP customers.

In the event an applicant seeks an accounting order to establish a new deferral/variance account, the following eligibility criteria must be met:

- Causation - The forecasted expense must be clearly outside of the base upon which rates were derived.
- Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
- Prudence - The nature of the costs and forecasted quantum must be reasonably incurred although the final determination of prudence will be made at the time of disposition. In terms of the quantum, this means that the applicant must provide evidence demonstrating as to why the option selected represents a cost-effective option (not necessarily least initial cost) for ratepayers.

In addition, applicants must include a draft accounting order which must include a description of the mechanics of the account, including providing examples of general ledger entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.12.6 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant should refer to *Guideline G-2008-0011: Smart Meter Funding and Cost Recovery – Final Disposition*, 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 completed smart meter model.

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 has upheld the cessation of the SMFA as of April 30, 2012 in most decisions for 2012 IRM applications. 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 cost of service applications for 2013 or later 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, if not previously addressed in a prior stand-alone or cost of service application.

Where a distributor has had some or all of its smart meter costs reviewed for prudence and approved for recovery in a previous cost of service or stand-alone application, the applicant should clearly document this, and in the latter case, should identify the specific adjustments to rate base and OM&A.

This page was intentionally left blank

Ontario Energy Board Commission de l’énergie de l’Ontario

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Ontario Energy Board

Chapter 3 of the Filing Requirements For Electricity Transmission and Distribution Applications

June 28, 2012

Table of Contents

Chapter 3 Filing Requirements for Incentive Regulation Mechanism Rate Applications

1.0 Introduction

The Ontario Energy Board establishes the rates of electricity distributors using a combination of annual incentive regulation mechanism ("IRM") adjustments and periodic cost of service reviews.

The Filing Requirements herein replace version 3.0 of Chapter 3 of the *Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements"), dated June 22, 2011. The requirements set out the Board's expectations for filings by electricity distributors that are applying for annual rate adjustments under an IRM plan.

In its October 27, 2010 letter regarding the development of a Renewed Regulatory Framework for Electricity ("RRFE"), the Board announced that it was extending the 3rd Generation IRM ("IRM3") plan until such time as three RRFE policy initiatives have been substantially completed. As such, the four-year rate-setting cycle (i.e. rebasing plus three years of IRM) remains in place for the time being.

Version 3.0 of Chapter 3 of the Filing Requirements announced that the Board was no longer allowing distributors to file a 2nd Generation IRM application. The Board determined that the IRM3 plan would provide a uniform IRM framework to all distributors, including those that have not rebased since the 2006 EDR but elected to remain on an IRM plan. Hence, all IRM applications must be filed under IRM3.

1.1 Key References

The documents listed below are key to understanding these Filing Requirements:

- *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism for Ontario's Electricity Distributors* (filing guidelines: Appendix F) – December 20, 2006;
- *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009
- *Guidelines for Electricity Distributors' Conservation and Demand Management* (EB-2012-0003) – April 26, 2012;
- *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008;
- *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – September 17, 2008;
- *Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – January 28, 2009;
- *Guideline (G-2008-0001) on Retail Transmission Service Rates* – October 22, 2008 (Revision 3.0 June 22, 2011 and any subsequent updates);
- *Guideline G-2011-0001:Smart Meter Funding and Cost Recovery – Final Disposition*, December 15, 2011;
- *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)* – July 31, 2009;
- *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397) - May 17, 2012;
- *Report of the Board on Transition to International Financial Reporting Standards* EB-2008-0408 – July 28, 2009; and
- *Addendum to Report of the Board EB-2008-0408 – Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* – June 13, 2011 and the letter of the Board, dated April 30, 2012.

1.2 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2013 will be required to file their IRM application by August 3, 2012.

For those distributors that are seeking rate adjustments effective May 1, 2013, the Board will assign electricity distributors in one of six application groupings noted below based on the expected level of complexity of the application. The length of time required to review an application is commensurate upon its level of complexity. Applications of greater complexity and hence requiring more time to review will be required to be filed first. Staggering of the applications allows the Board and other stakeholders to appropriately schedule resources to allow for adequate review of the applications. The deadlines for filing an IRM application have been determined so that, in the normal course of events, a Decision and Order would be issued in time for a May 1 implementation date.

The application deadlines are as follows:

- Friday August 31, 2012
- Friday September 14, 2012
- Friday September 28, 2012
- Friday October 12, 2012
- Friday October 26, 2012
- Friday November 9, 2012

Board staff will survey potential IRM applicants in June 2012 requesting that applicants that are seeking rate adjustments effective May 1, 2013 identify the expected elements of their IRM application for the purpose of assisting the Board in assigning a filing deadline for each electricity distributor. Applicants expected to include one or more of the following elements in their application will be assigned an earlier filing date :

- LRAM to account for persistence of 2010 CDM programs in 2011 and 2012;
- LRAM Variance Account disposition;
- Rate Harmonization pursuant to a prior Board decision;
- Z Factor claim;
- Incremental Capital Module claim;
- Smart Meter Cost Recovery; and
- Renewable Generation and/or Smart Grid Rate Adder request.

The assignment of distributors under these filing dates will be identified in a separate communication.

1.3 Components of the Application Filing

Each application must include:

- A Manager's Summary thoroughly documenting and explaining all rate adjustments applied for;
- The contact information for the IRM application - The primary contact for the IRM 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 IRM application, the Board will revert communication to the primary licence contact;
- A completed Rate Generator[1] and supplementary work forms[2], provided by the Board, both in electronic (i.e. Excel) and PDF format;
- A PDF copy of the current Tariff Sheet;
- Supporting documentation cited within the application (e.g. excerpt of relevant past decisions and/or settlement agreements, relevant Reporting and Record-keeping Requirements ("RRR") data and Revenue Requirement Work Form ("RRWF"))[3];
- A statement as to which publication(s) the applicant's notice will be appearing, whether it is a paid publication or not and the readership and circulation numbers; and
- A text-searchable Adobe PDF format for all documents.

1.4 Bill Impacts

The Rate Generator includes a bill impact calculation by rate class and produces total bill impacts excluding any changes to the Regulated Price Plan ("RPP"). These calculations are similar to that used in assessing rate applications in recent years. The latest RPP at the time of publication of the Rate Generator model will be used and will remain unchanged for the duration of the application process.

[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in an IRM Application.
[2] Include the Shared Tax Savings Workform, Revenue Cost Ratio Adjustment Workform, Incremental Capital Module Workform, Deferral and Variance Account Workform and RTSR Adjustment Workform.
[3] The Revenue Requirement Work Form is filed as part of the draft rate order in the last rebasing application.

1.5 Applications and Electronic Models

The models issued by the Board are provided to assist the distributor in filing a rate application. An application to the Board is the distributor's responsibility and the Board expects that the application will be complete and accurate. While the Board may issue electronic filing models for use in IRM rate applications, the distributor bears the responsibility to ensure the accuracy and appropriateness of any models that it uses in supporting its application. The distributor is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models. Utilization of the models issued by the Board does not necessarily constitute Board acceptance.

1.6 Other Rate Adjustments

The Rate Generator will be made available on the Board's web site. The model will include generic base rate adjustments, rate adders and rate riders common to most applicants. Where a distributor has continuing adjustments, and/or rate adders and/or rate riders from previous decisions that are not in the generic model (such as the phased implementation of a rate harmonization process) the distributor should contact Board staff for specific guidance.

2.0 Elements of the IRM Plan

2.1 Price Cap Index Adjustment

The Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI) as published by Statistics Canada will be used as the price escalator for IRM applications.

For rates effective January 1, 2013, the GDP-IPI will be the annual percentage change in the GDP-IPI for the period 2011 Q3 to 2012 Q2 to 2010 Q3 to 2011 Q2. For rates effective May 1, 2013, the GDP-IPI will be the annual percentage change for calendar year 2012.

The Rate Generator will originally include the preceding calendar year's GDP-IPI value as an estimate of the inflationary adjustment to input prices (i.e. costs) for the upcoming rate year. Statistics Canada typically publishes data approximately two months following a period. Upon publication by Statistics Canada, the Board will issue a letter establishing the updated GDP-IPI. Board staff will update the GDP-IPI in each distributor's Rate Generator in order to calculate the price cap index adjustment for final distribution rates for all applicants. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment is determined as the annual percentage change in the GDP-IPI less the X-Factor. The X-factor is 0.72% plus a stretch factor. The value of the stretch factor is specific to each distributor for each rate year, and will be one of the following values: 0.2%; 0.4%; or 0.6%. The Board will determine each distributor's stretch factor. The distributor specific stretch factors will not be available before the application is filed. Therefore, the Rate Generator will include a proxy stretch factor of 0.4%. Once the distributor specific stretch factors become available, Board staff will adjust the stretch factor in each distributor's individual Rate Generator. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

The price cap index adjustment will not be applied to the following components of delivery rates:

- Rate Adders;
- Rate Riders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- MicroFIT Service Charge;
- Specific Service Charges; and
- Transformation and Primary Metering Allowances.[4]

2.2 Incremental Capital Module

The incremental capital module ("ICM") is intended to address the treatment of new capital investment needs that arise during the IRM plan term which are incremental to the materiality threshold defined below.

The eligibility criteria to recover amounts that are incremental to capital investment needs are included in section 2.5 of the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, dated* July 14, 2008 and are reproduced below.

4 and any other allowances the Board may determine.

Criteria	Description
Materiality	The amounts must exceed the Board-defined materiality threshold and clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	Amounts should be directly related to the claimed driver, which must be clearly non-discretionary. The amounts must be clearly outside of the base upon which rates were derived.
Prudence	The amounts to be incurred must be prudent. This means that the distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.2.1 ICM Materiality Threshold

The ICM materiality threshold is discussed in section 2.3 of the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Supplemental Report") EB-2007-0673.

The Board has determined that the following formula is to be used by a distributor to calculate the materiality threshold that will apply to it:

$$\textit{Threshold Value} = 1 + \left(\frac{RB}{d}\right) * (g + PCI * (1+g)) + 20\%$$

Where:

RB = rate base included in base rates ($);

d = depreciation expense included in base rates ($);

g = distribution revenue change from load growth (%); and

PCI = price cap index (% inflation less productivity factor less stretch factor).

The values for "RB" and "d" are the Board-approved amounts in the distributor's base year rate decision.

The value for "g" is the % difference in distribution revenues between the most current complete year and the base year.

The following table provides an example of the calculation of the materiality threshold values.

An Illustration:

Assumptions:	RB	=	\$100 million;
	d	=	\$5 million;
	g	=	1.5% (0.015); and
	PCI	=	0.75% (0.0075).
Calculation:	$1+(\frac{100,000,000}{5,000,000})*(0.015+.0075*(1+0.015))+0.20=1.65$		
Result:	The materiality threshold (CAPEX/Depreciation) is 1.65 or 165%. That is, given the assumptions in this example, the Board expects the distributor to manage a CAPEX level of up to \$8.26 million (\$5 million * 1.65) before being eligible to apply to recover incremental amounts.		

2.2.2 Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amount sought for recovery should be new capital in excess of the materiality threshold. The materiality threshold value, as calculated using the formula discussed in Section 2.2.1, establishes eligibility for incremental capital spending and also marks the base from which to calculate the maximum amount eligible for recovery. A distributor applying for recovery of incremental capital should calculate the maximum allowable capital amount by taking the difference between the 2013 total non-discretionary capital expenditure and the materiality threshold.

2.2.3 Application of the Half-Year Rule

The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In this report the Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the IRM plan term[5]. The Board has adopted this as a clarification to the policy on ICM.

2.2.4 Revenue Requirement Calculation

When calculating the revenue requirement associated with the ICM, a distributor should use the following parameters:

- Cost of Capital
    - In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, issued

[5] EB-2010-0130, Guelph Hydro Electric Systems Inc., *Decision and Order,* p. 15

December 20, 2006 ("2006 Report") the Board outlined the transition to a single deemed capital structure of 60% debt and 40% equity. Since all distributors have completed the transition to a 60/40 debt-equity ratio, a distributor filing for an ICM adjustment shall use this deemed capital structure.

- On December 11, 2009 the Board issued the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report"). The 2009 Report sets out revised cost of capital parameters to be effected in cost of service applications. A distributor filing an ICM adjustment, shall use the last Board-approved cost of capital parameters determined during the distributor's last rebasing application when calculating the revenue requirement associated with the ICM.

- PILS
  - Since currently known legislated tax changes from the level reflected in the Board-approved base rates for a distributor will be reflected in the IRM adjustments, a distributor filing for an ICM adjustment should apply the current tax rates when calculating the revenue requirement associated with the ICM.

- Working Capital Allowance ("WCA")
  - A distributor filing an ICM adjustment shall use the last Board-approved WCA determined during the distributor's last rebasing application when calculating the revenue requirement associated with the ICM.

2.2.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM3 plan term must include comprehensive evidence to support the claimed need, which should include the following:

- An analysis demonstrating that the materiality threshold test has been met and that the amounts will have a significant influence on the operation of the distributor;
- Justification that the amounts to be incurred will be prudent. This means that the distributor's decision to incur the amounts represents the most cost-effective option (not necessarily least initial cost) for ratepayers;
- Justification that amounts being sought are directly related to the claimed cause, which must be clearly non-discretionary and clearly outside of the base upon which current rates were derived.

- Evidence that the incremental revenue requested will not be recovered through other means (e.g., it is not, in full or in part, included in base rates or being funded by the expansion of service to include new customers and other load growth);
- Details by project for the proposed capital spending plan for the test year segregated between discretionary and non-discretionary;
- A description of the proposed non-discretionary capital projects and expected in-service dates;
- Calculation of the revenue requirement associated with each proposed incremental non-discretionary capital project (i.e. the cost of capital, depreciation, and PILs);
- Calculation of revenue requirement offsets associated with each incremental non-discretionary projects due to revenue to be generated through other means (e.g. customer contributions in aid of construction);
- A description of the actions the distributor will take in the event that the Board does not approve the application.
- Calculation of a rate rider to recover the incremental revenue from each class and the rationale for the proposed approach.

2.2.6 ICM Reporting Requirements

A distributor that receives rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of the next rebasing, the distributor will file a calculation of the amounts to be incorporated in rate base. At that time the Board will make a determination on the treatment of any difference between forecast and actual capital spending during the IRM plan term. Any overspending or underspending will be reviewed at the time of rebasing.

2.2.7 ICM Accounting Treatment

The distributor will record eligible ICM amounts in Account 1508, Other Regulatory Asset, sub-account Incremental Capital Expenditures, subject to the assets being used and useful. For incremental capital assets under construction, the normal accounting treatment will continue in the construction work in progress (“CWIP”) prior to these assets going into service and hence eligible for recording in the 1508 sub-account. The amortization of capital assets for the relevant accounting period will be recorded in a separate amortization account of the sub-account, Incremental Capital Expenditures. In addition, the revenues collected from the rate rider will be recorded in Account 1508, Other Regulatory Asset, sub-account, Incremental Capital Expenditures rate rider.

The distributor shall also record monthly carrying charges in sub-accounts Incremental Capital Expenditures and Incremental Capital Expenditures rate rider. Carrying charges amounts are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of account 1508. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published in the Board's web site.

2.2.8 Rate Generator and Supplemental Filing Module for ICM

The supplemental filing module supporting the Rate Generator will assist the distributor in calculating the distributor's threshold. The distributor will then tabulate the value of its eligible non-discretionary investments and compare this to the threshold. Other calculation work forms will be provided to calculate the revenue requirement for each project proposed for inclusion in the ICM request in the supplemental filing module. Once all work forms are completed and listed in the supplemental module, the tabulated revenue requirement will be converted into a rate rider.

2.3 Z-factor Claims

Z-factors are intended to provide for unforeseen events outside of a distributor's management control. The cost to a distributor must be material and its causation clear. A distributor must follow the guidelines listed below when applying to the Board to recover the amounts that the distributor has recorded in a Board-approved deferral account related to a Z-factor claim.

2.3.1 Eligibility Criteria for Z-factor Amounts

The eligibility criteria for a request to recover amounts by way of a Z-factor are discussed in section 2.6 of the *Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* – July 14, 2008, and are summarized in Table 1 below. In order for amounts to be considered for recovery by way of a Z-factor, the amounts must satisfy all three eligibility criteria set out in Table 1 below.

Table 1: Z-factor Amount Eligibility Criteria

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the distributor's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

2.3.2 Materiality Threshold

The following materiality thresholds will apply:

- $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 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.

The materiality threshold must be met on an individual event basis in order for the relevant costs to be eligible for potential recovery.

2.3.3 Z-factor Filing Guidelines

A distributor must submit evidence that the costs incurred meet the three eligibility criteria outlined above. A distributor must also:

- Notify the Board by letter to the Board Secretary of all Z-factor events. Failure to notify the Board within six months of the event may result in disallowance of the claim.
- Apply to the Board for any cost recovery of amounts recorded in the Board-approved deferral account claimed under Z-factor treatment. This will allow the Board and any affected distributor the flexibility to address extraordinary events in a timely manner. Subsequently, the Board may review and prospectively adjust the amounts for which Z-factor treatment is claimed.
- Provide a clear demonstration that the management of the distributor could not have been able to plan and budget for the event and that the harm caused by the event is genuinely incremental to its experience or reasonable expectations.
- Demonstrate that the costs are incremental to those already being recovered in rates as part of ongoing business exposure risk.

2.3.4 Other Matters in Relation to Z-Factors

As part of its claim, a distributor must outline the manner in which it intends to allocate the incremental revenue requirement to the various customer rate classes, the rationale for the selected approach and a discussion of the merits of alternative allocation methods. Recovery will be through a rate rider[6]. The request must specify whether the rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the

[6] See Appendix C

length of the disposition period and a rationale for this proposal. A detailed calculation of the rate rider(s) must be provided.

2.3.5 Z-factor Accounting Treatment

The distributor will record eligible Z-factor cost amounts in Account 1572, Extraordinary Event Costs, of the Board's Uniform System of Accounts (the "USoA") contained in the *Accounting Procedures Handbook* ("APH") for electricity distributors. Monthly carrying charges shall be recorded in Account 1572. Carrying charges are calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account. The rate of interest shall be the rate prescribed by the Board for deferral and variance accounts for the respective quarterly period published on the Board's web site.

2.4 Off-ramps

An off-ramp is based on a pre-defined set of conditions under which the IRM plan would be terminated or modified before its normal end-of-term date due to excessive over or under earnings.

For IRM3, the Board determined that the plan will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. A distributor will be required to report to the Board no later than 60 days after the company's receipt of its annual audited financial statements, in the event that the distributor's earnings falls short of or exceeds its ROE by 300 basis points. The Board will also monitor results filed by distributors as part of their reporting and record-keeping requirements. A review will be carried out by the Board to determine if further action by the Board is warranted. Any such review would be prospective in nature, and could result in modifications to the IRM3 plan, a termination of the IRM3 plan or the continuation of the IRM3 plan for that distributor.

2.5 Tax Changes

Under an IRM3, a 50/50 sharing[7] of the impact of currently known legislated tax changes as applied to the tax level reflected in the Board-approved base rates for a distributor applies. The calculated annual tax changes over the plan term will be allocated to customer rate classes on the basis of the most recent Board-approved base-year distribution revenue. These amounts will be collected from or refunded to customers each year of the plan term, over a 12-month period, through an explicit volumetric rate rider derived using annualized consumption by customer class underlying the Board-approved base rates.

[7] Supplemental Report of the Board on 3rd Generation Incentive Regulation – September 17, 2008

A shared tax saving workform will include a schedule for a distributor to complete, which will calculate the volumetric rate rider. Occasionally, the calculated rate riders for one or more rate classes may be negligible. In the event that the calculation for one or more rate classes results in volumetric rate riders of $0.0000 when rounded to the fourth decimal place, or is negligible, the distributor may request to record the total amount in USoA account 1595 for disposition in a future proceeding.

3.0 Implementation Matters

3.1 Deferral and Variance Account Balances

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that during the IRM plan term, the distributor's Group 1 audited account balances will be reviewed and disposed if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed.

Distributors must file in their application Group 1 balances as of December 31, 2011 to determine if the threshold has been exceeded. A continuity schedule, found on sheet 9 of the Rate Generator, must be completed as part of the application, regardless of whether or not the preset disposition threshold has been met.

Group 1 consists of the following USoA accounts:

- 1550 Low Voltage Account;
- 1580 RSVA Wholesale Market Service Charge Account;
- 1584 RSVA Retail Transmission Network Charges Account;
- 1586 RSVA Retail Transmission Connection Charge Account;
- 1588 RSVA Power Account;
- 1588 RSVA Global Adjustment Sub-Account;
- 1590 Recovery of Regulatory Asset Balances Account; and
- 1595 Disposition and Recovery/Refund of Regulatory Balances Account.

The EDDVAR Report states that the default disposition period to clear the Group 1 account balances by means of a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.

The global adjustment sub-account captures the difference between the amounts billed (or estimated to be billed) to non-RPP customers by the distributor and the actual amount paid by the distributor to the IESO.

During the 2010, 2011, and 2012 EDR process, the Board determined that a separate rate rider included in the delivery component of the bill would apply prospectively to non-RPP customers to dispose of the global adjustment sub-account balances.

In March of 2012, the Board updated the APH. The Board revised Account 1588 RSVA Power, Sub-account Global Adjustment and established a separate account for the global adjustment, Account 1589, RSVA Global Adjustment, effective January 1, 2012. Since balances as of December 31, 2011 will be subject to the Board's review as part of the 2013 IRM application, this change will apply to 2014 rate applications only.

3.2 Revenue-to-Cost Ratio Adjustments

The Board's Decisions for some distributors' 2010, 2011 and 2012 cost of service rate applications prescribed a phase-in period to adjust the revenue-to-cost ratios. The Supplemental Filing Module and Rate Generator will include schedules for a distributor to effect revenue-to-cost ratio adjustments previously approved by the Board. The process will adjust base distribution rates before the application of the price cap adjustment.

3.3 Electricity Distribution Retail Transmission Service Rates

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").

The Board will provide a filing module to distributors to assist in calculating the distributor's class-specific RTSRs. The filing module will reflect the most recent UTRs approved by the Board (EB-2011-0268), issued on December 20, 2011 and effective January 1, 2012. Once any January 1, 2013 UTR adjustments are determined, Board staff will adjust each distributor's 2013 RTSR model and Rate Generator to incorporate these changes. Distributors will have an opportunity to comment on the accuracy of Board staff's updates as part of the draft Rate Order process.

3.4 Conservation and Demand Management ("CDM") Costs

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 Board expects that, going forward, most CDM funding for distributors for the 2012-2014 period, will be provided by the Ontario Power Authority ("OPA"). It is expected that a distributor will enter into contracts to deliver OPA-Contracted Province-Wide CDM Programs. If a distributor seeks to deliver programs not being offered through the OPA-Contracted Province-Wide Programs, it is able to apply for Board approval for programs that are in compliance with the rules set out in the Board's CDM Code and clarified in the April 26, 2012 Conservation and Demand Management Guidelines (EB-2012-0003) (CDM Guidelines). This will be funded through the global adjustment mechanism, and therefore should not be included in distribution rates.

3.4.1 Lost Revenue Adjustment Mechanism

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.

On April 26, 2012, the Board issued updated CDM Guidelines. The CDM Guidelines were developed to provide more clarity on the CDM Code and what information needs to be filed in support of Board-Approved CDM program applications, as well as to provide updated details on the LRAM and the associated variance account for the 2011-2014 term.

3.4.2 LRAM Variance Account ("LRAMVA") for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 term, the Board established Account 1568 as the LRAMVA to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate class level. Accounting guidelines regarding the LRAMVA can be found in Appendix B of the 2012 CDM Guidelines. Distributors should refer to the CDM Guidelines for further details.

The distributor shall compare the Board-approved forecasted CDM related load forecast reduction to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

3.4.3 Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their IRM rate applications, if the balance is deemed significant by the applicant.

In support of its application for lost revenues distributors must file the following:

- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its

LRAM amount;

- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- For Board-approved programs, a third party report, in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code, that provides a review and verification of the LRAM calculations, including:
    - Confirmation of the use of correct input assumptions and LRAM calculations
    - Verified participation amounts
    - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
    - Verification of any carrying charges requested; and
- For OPA Contracted Province-Wide Programs the distributor must provide documentation (i.e. final evaluation report from the OPA) of the distributor's results.

A separate third party review of the distributors OPA-Contracted Province-Wide CDM programs is not required.

3.4.4 LRAM and/or SSM for pre-2011 CDM activities

In Section 3.4.2 of Chapter 3 of the Filing Requirements, issued June 22, 2011, the Board stated that 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 the legacy period of CDM activity (2005 – 2010).

The Board expects LRAM claims for pre-2011 CDM activities to have been completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application. SSM is not applicable for savings persisting from the legacy period.

In support of its application for persisting lost revenues from pre-2011 CDM programs, distributors must file the following:

- A statement confirming that the distributor's load forecast has not been updated as part of a cost of service application since the CDM programs, for which persistent lost revenue is sought, were implemented;
- A statement indicating that the distributor has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;
- Separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place;
- LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;
- A statement, and if applicable a table, that indicates if carrying charges are being requested on the LRAM amount;
- A third party report that provides a review and verification of the LRAM calculations, including:
  - Confirmation of the use of correct input assumptions and LRAM calculation
  - Verified participation amounts
  - The net and gross kW and kWh impacts of each program and for each class, both gross and net of free riders, separated by year
  - Verification of any carrying charges requested.

3.5 Distribution System Plans - Filing under Deemed Conditions of Licence

The *Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence* (EB-2009-0397) revised on May 17, 2012 (originally issued on March 25, 2010), recognized that distributors may need additional funding for expenditures proposed in a GEA Plan between cost-of-service applications. For 2013 IRM applications, distributors may request the following:

- Renewable Generation Connection Funding Adder; and
- Smart Grid Funding Adder.

Where a distributor seeks a funding adder, sufficient information must be provided to allow the Board to assess the need for the mechanism and the nature and quantum of the costs to be collected from ratepayers and the basis for calculating the funding adder. The costs recovered through the funding adder will be subject to a prudence review in the first cost of service application following the implementation of the funding adder. A refund to ratepayers may be ordered if the Board find that the expenditures upon which the adder was based were not prudently incurred.

In the Distribution System Plan Filing Requirements, the Board created two additional deferral accounts to record the amounts collected from ratepayers through the funding adders:

- Account 1533: Renewable Generation Connection Funding Adder Deferral Account

  This account will record the revenues collected through a funding adder approved by the Board related to renewable generation connection projects. Separate sub-accounts shall be used to record any amounts collected from a distributor's ratepayers and any amounts received from the IESO (pursuant to the provincial pooling mechanism set out in 79.1 of the OEB Act) in respect of the projects.

- Account 1536: Smart Grid Funding Adder Deferral Account
  This account will record the revenue collected through a funding adder approved by the Board related to smart grid development.

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

The Board provided general guidance on this topic in the *Report of the Board, Transition to IFRS,* issued on July 28, 2009 and in associated amendments available on the IFRS page of the Board's website (amendments are dated November 8, 2010 and April 30, 2012).

On June 13, 2011 an *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (EB-2008-0408) (the "Addendum") was issued following a working group process. The Addendum sets out additional regulatory policy regarding the transition to IFRS in the circumstance where utilities rates are rebased using cost of service rate setting methods and where rates are subsequently set using an IRM. For distributors that rebased under CGAAP and are filing an IRM application, issues 1 and 2 in the Addendum are of particular relevance.

For those distributors who rebased under CGAAP and are filing an IRM application where a distributor seeks an ICM, and/or Z-factor treatment, the financial information supporting the rate adjustments must be provided under CGAAP. The adjustments to rates will also be made on the basis of CGAAP.

In addition, a reconciliation of the CGAAP-based financial information for an ICM or Z factor to the relevant information in the last annual RRR reporting under modified IFRS is required. Where the applicant has adopted IFRS for financial reporting, but has not yet made an annual RRR reporting under modified IFRS, the financial information mentioned above must be provided in both CGAAP and modified IFRS format, and a reconciliation provided between the two accounting standards. No third party assurance is required for the reconciliations, although an applicant can choose to file such assurance as part of its evidence supporting the reconciliation.

The Board authorized the creation of a generic IFRS transition PP&E deferral account, Account 1575, that the applicants must use to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS. In general, this account will be cleared at the first rebasing application under MIFRS.

Utilities that file and report under USGAAP (or another accounting standard) should, in general, read references to IFRS and MIFRS in the Filing Requirements to include USGAAP (or other alternate accounting standard). The deferral account authorized in Issue 2 of the Addendum may not be necessary for such utilities.

4.0 Specific Exclusions from IRM Applications

The IRM application process is intended to streamline the processing of a large volume of rate adjustment applications, and is therefore intended to be mechanistic in nature. For this reason, the Board has determined that the IRM process is not the appropriate venue by which a distributor should seek relief on issues which are substantially unique to an individual distributor or more complicated and potentially contentious. The following are examples of specific exclusions from the IRM rate application process:

- Rate Harmonization, other than that pursuant to a prior Board decision;
- Changes to revenue-to-cost ratios, other than pursuant to a prior Board decision;
- Loss Factor Changes;
- Re-setting of Specific Service Charges;
- Loss Carry Forward Adjustments to PILs/taxes; and
- Loss of Customer Load.

Exclusions from the IRM process are to be addressed in the distributor's next cost of service application. With respect to smart meter cost recovery, a distributor may elect to include this element as part of its 2013 IRM application if the timing of the smart meter cost recovery application coincides with the filing of the IRM application. Otherwise, the review of smart meter costs should be addressed in a separate (or stand alone) application.

Appendix A: Disposition of Residual Balance in USoA Account 1590 or 1595

The 2006 Regulatory Assets process disposed of all balances in the regulatory asset accounts as of December 31, 2004. The decisions for each distributor resulted in the disposition of the approved amounts by way of final rate riders and the transfer of the approved amounts to account 1590. Likewise, any deferral and variance account balances post December 31, 2004 that have been approved by the Board for disposition were disposed on a final basis, unless otherwise noted and should have been transferred to account 1595.

Accounts 1590 and 1595 are part of the Group 1 deferral and variance accounts as defined by the Board in the EDDVAR Report. Once the rate rider ceases, the residual principal balances and any interest carrying charges in these accounts would be cleared in an IRM application (where applicable) provided that the preset disposition threshold for the Group 1 accounts has been exceeded.

Appendix B: Application of Recoveries to Principal and Interest Carrying Charges Amounts in Account 1595

When final approval for disposition of deferral and variance account balances is received from the Board, the final approved amounts of principal and interest carrying charges is transferred to account 1595.

The cumulative principal balance transferred to account 1595 is drawn down by the rate rider recoveries, and interest carrying charges are applied to the principal balance net of recoveries.

The following approach is used for the application of recoveries (via rate riders) to the transferred amounts under two scenarios:

Scenario 1: Rate Rider ceases with Principal amount remaining.

If the rate rider ends before the principal is fully drawn down, the principal balance is held static and interest carrying charges are applied to the remaining principal balance. The approved rate rider flowing from the next application to dispose of deferral and variance accounts should include the remaining principal and interest carrying charges.

Scenario 2: Rate Rider ceases with no Principal amount remaining but with Interest Carrying Charges remaining.

The approved rate rider flowing from the next application to dispose of deferral and variance account balances should include the cumulative interest carrying charge amounts.

Appendix C: Rate Adder versus Rate Rider

Rate Adder

A rate adder (or funding adder) is a tool designed to provide advance funding on an interim basis to distributors for certain investments or expenses as prescribed by the Board and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the Board. Approval of a rate adder does not constitute regulatory approval of any costs actually incurred. The prudence of such costs is examined, and the costs are approved in whole or in part, at the time at which the distributor brings the matter forward for regulatory review.

Rate adders are identified and listed separately on a distributor's Tariff of Rates and Charges and may have a sunset or termination date.

Rate Rider

A rate rider differs from a rate adder in that it is designed to recover or refund Board-approved amounts following a prudence review. Rate riders are identified and listed separately on a distributor's Tariff of Rates and Charges, with an explicit sunset or termination date.

Materiality for Rate Adders and Rate Riders

Rate adders and rate riders normally apply to one or more select rate classes on a fixed basis, a volumetric basis or a combination of both. A rate adder or rate rider is usually determined by dividing the Board-approved allocated amounts by the Board-approved forecast or historical energy use or demand.

Occasionally, the calculated rate adders or rate riders for one or more rate classes may be negligible. In the event where the calculation of one or more rate adder or rate rider results in volumetric rate riders of $(0.0000) when rounded to the fourth decimal place, , or are negligible the entire Board-approved amount for recovery or refund shall be recorded in a USoA account to be determined by the Board for disposition in a future rate setting.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 4 of the Filing Requirements For Electricity Transmission and Distribution Applications

May 17, 2012

Table of Contents

Chapter 4 Minimum Filing requirements for electricity transmission projects under Section 92 of the Ontario Energy Board Act ("the Act")

4.1 Introduction

The Act requires transmitters and distributors to obtain leave of the Board for the construction, expansion, or reinforcement of electricity transmission and distribution lines or interconnections; however, Ontario Regulation 161/99 has specified that this requirement applies only to transmission lines greater than 2 kilometres in length. A transmission system is defined as a system for conveying electricity at voltages greater than 50 kilovolts ("kV").

The filing requirements set out in this document are not intended to limit applicants in terms of what information they may want to present. Nor do these filing requirements limit the discretion of the Board in terms of what information and evidence it may wish to see.

In addition to the need to obtain leave to construct, under section 81 of the Act, any generator or an affiliate of a generator planning to construct transmission facilities must give notice to the Board per guidelines available on the Board's website **www.ontarioenergyboard.ca/documents/cases/Maad/guidelines.pdf**. The Board upon examining the relevant facts may choose to formally review the application by holding a hearing, and in that event will advise the applicant within 60 days of receiving the application of its intention to formally review that application.

Construction of new transmission facilities may also require an amendment to a transmitter license issued by the Board.

Any person who obtained leave of the Board to construct facilities under section 92 or who is exempt under section 95 may apply to the Board for authority to expropriate land for that purpose.

The Board's role in assessing applications for leave to construct transmission lines under section 92 is to ensure that the proposed projects are in the "public interest". Section 92:

> **92.** (1) No person shall construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection without first obtaining from the Board an order granting leave to construct, expand or reinforce such line or interconnection. 1998, c. 15, Sched. B, s. 92 (1).

Note, however, that subsection 96(2) specifies that for section 92 purposes in determining whether the construction, expansion or reinforcement of the electricity transmission line or interconnection is in the public interest, the Board shall only consider the following:

> "1. The interests of consumers with respect to prices and the reliability and quality of electricity service."
>
> 2. Where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources."

4.2 The Regulatory Framework

4.2.1 Legislation

Section 92 of the Act requires leave of the Board for the construction, expansion, or reinforcement of an electricity transmission line or an electricity distribution line, as well as for the making of a connection to the power system. Under Ontario Regulation 161/99 however, many projects that would otherwise require approval under s. 92 of the Act are exempt from the need for leave to construct. This includes all distribution projects and most connections and projects involving electricity transmission lines that are 2 kilometres or less in length.

Section 95 of the Act allows an applicant to seek an exemption from the requirements of s. 92 of the Act. An applicant must submit such a request accompanied by the special circumstances that warrant an exemption from the requirement to obtain leave to construct under s. 92 of the Act. A project summary report should be submitted for review, consistent with the requirements described in this document. The level of detail in the submission should reflect the issues or concerns encountered during the evaluation phase of the project.

Section 97 requires that information on land requirements must be included as part of the leave to construct application. Section 97 of the Act states, "leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board."

4.2.2 Related Regulatory Hearings

Board review of transmission investment can arise in regulatory settings other than a leave to construct application. For example, the Board's authority to review transmitter's capital budgets and set rates is established in subsection 78 (1) of the Act which states "No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract."

Avoiding duplication of regulatory review is therefore critical. The conclusions of the Board specific to a project that are made in one regulatory proceeding will not generally be re-evaluated in another proceeding. However, this must have been a discreet finding of the Board in a previous decision, not simply that information was filed in an application. For example, if the need for a project is clearly established in a leave to construct application, this need would not need to be re-evaluated in a subsequent rate proceeding to determine transmission rates; and to the extent that the project's costs and timing had not changed, the Board's review of these may not need to be comprehensive. However, if the leave to construct is preceded by the transmitter's rate case, the need for the project may not have been dealt with in sufficient detail to satisfy the requirements of a leave to construct proceeding. If the project had received approval in a rate hearing as part of an envelope of expenditures rather than as a discreet approval of the particular project, that panel would likely revisit the valuation of the project in some detail. The intent, however, is not to re-assess that which has already been specifically addressed in a related proceeding.

In addition to a leave to construct approval, most transmission projects will require various other regulatory approvals: for example, an environmental assessment approval. In some cases, these approvals will be obtained after the Board issues a leave to construct approval. It is possible that conditions attached to these approvals may result in material changes to the project that was reviewed by the Board (for example, a routing change or the imposition of additional costs that were not known to the Board). Under such circumstances, an applicant will be required to satisfy the Board that the project is still in the public interest.

4.3 Applicant and Project Types

In all electricity leave to construct applications under section 92(1), the Board considers the interests of consumers with respect to prices and the reliability and quality of electricity service, and, where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources."

The filing requirements differ depending on the type of applicant and project.

Applicants can be rate regulated, such as licensed transmitters that provide transmission services to third parties at Board-approved rates, or non-rate regulated, such as an owner of a large industrial plant or a generation facility that does not provide transmission services to third parties.

Rate-regulated applicants

There is an onus on rate-regulated entities whose revenues are derived from ratepayers to justify before the Board all expenditures on transmission facilities.

A rate-regulated transmitter applying for a leave to construct for a proposed project must provide all the minimum filing requirements with the application, whether or not the project has been included in a capital budget that has been approved in a rate hearing.

Rate-regulated transmitters and distributors applying for transmission connection projects are subject to additional requirements as set out in the Transmission System Code (“TSC”) in the application to the Board.

Non Rate-regulated Applicants

Most of the projects proposed by non rate-regulated applicants are designed to connect generation or load sites or plants to the existing IESO controlled grid. The financial risk of constructing new transmission facilities lies with the owners and shareholders of the company, and not with rate payers. As rate payer money is not involved, these applicants generally do not need to justify their expenditures on their own transmission facilities to the Board. However, it should be noted that in certain circumstances these owners and shareholders may be required by the Board to share some or all of the costs associated with the Network Reinforcement, as set out in Section 6.3 of the TSC. In that case the Board will want to ensure that the shared costs are appropriately assigned.

Section 6.3 of the TSC sets out how cost sharing will need to be justified. Transmitters and distributors applying for transmission connection projects must include additional information as set out in the TSC in their applications to the Board, such as the calculation of any capital contribution, and the relevant annual connection rate revenues over the applicable evaluation period if the costs are not recoverable in connection rate revenues.

Distribution Projects

Section 92 also applies for distributors’ projects involving transformation connection projects (e.g. a transformer station transforming from above 50 kV to below 50 kV), if the transmission line tap is more than 2 km in length. Facilities with voltages which are above 50kV and with line connections greater than 2km in length and which are or might be “deemed distribution” facilities are also subject to Section 92.

4.4 Filing Requirements for Projects under Section 92

The analysis of public interest implications may vary depending on the Applicant (rate-regulated or non rate-regulated) and type of transmission project being reviewed. The following minimum filing requirements apply to projects in a leave to construct proceeding. The exhibit designation is a suggestion and is not mandatory.

Exhibit A: Index

An index table listing exhibit numbers, tabs and schedules, and each of their contents shall be provided.

Exhibit B: The Application

1. Administrative

This section should include the formal signed application, which must include the following:

- the name of the applicant and partnerships involved in the application;
- the authorized representative of the applicant, phone, e-mail, fax and delivery address;
- an outline of the business of the applicant and parties in the application;
- an explanation of the purpose of the project for which leave to construct is being sought ;
- the financial structuring for the project, as necessary;
- a concise description of the routing and location of the project, including the affected municipalities and regions;
- a description of project components and their locations, activities, and related undertakings;
- the rationale for selecting the proposed project as opposed to any for alternatives considered
- an explanation of how the project is in the public interest, as defined by section 96(2) of the Act; and,
- the project schedule.

2. Project Overview Documents

The evidence in this section provides the background and a summary of the application, and assists the Board in drafting a Notice of Hearing for potential interested parties. This must include:

- a detailed description of location of the project and its components;
- maps (1:50,000 or larger) showing: the route, facility sites and any proposed ancillary facilities;

- the location of project components and related undertakings;
- line drawings of the proposed facility, showing supply connection(s) to the proposed facility and delivery facilities from the proposed facility to any adjacent transmission and/or distribution system(s); and
- the nominal rating of the main components of the project, including the transformers.

3. Need for the Project

In leave to construct applications, the Board's consideration is limited to the interests of consumers with respect to prices and the reliability and quality of electricity service and, where applicable and in a manner consistent with the policies of the Government of Ontario, the promotion of the use of renewable energy sources. This is mandated by section 96(2) of the Act, and the Board does not have the power to consider broader issues. The Board's consideration of the "need" for a project, therefore, can relate only to matters described in section 96(2).

Project justification delineates the responsibilities and necessary evidentiary components required for the project review. The responsibility for the provision of all evidence for the entire case rests with the applicant.

The applicant's evidence in support of the need for the project is required to be submitted and can be supported as necessary by evidence of the Independent Electricity System Operation ("IESO"), the transmitter, and/or the Ontario Power Authority: ("OPA"):

Where the Board has already considered aspects of the "price" consideration through a rates proceeding the applicant must still provide with their application:

- a description of the need for the project;
- a detailed reference to those approvals for any projects forming part of an approved plan or rate order; and,
- the reasons given for the inclusion of the project in those proceedings.

Classification of Project Need for Rate-regulated Transmitters:

This section relates to additional information required to be provided by rate-regulated Transmitters. Project Categorization, Classification and Justification assist in determining the need for the project. The categorization and classification are considered in a matrix as shown:

<table>
<tr><th colspan="4">PROJECT NEED</th></tr>
<tr><td colspan="2" rowspan="2"></td><th colspan="2">PROJECT Categorization</th></tr>
<tr><td>Non-discretionary</td><td>Discretionary</td></tr>
<tr><th rowspan="3">PROJECT Classification</th><td>Development</td><td></td><td></td></tr>
<tr><td>Connection</td><td></td><td></td></tr>
<tr><td>Sustainment</td><td></td><td></td></tr>
</table>

The classification and categorization is discussed in further detail here.

a) Project Classification

Project Classification is the classification of a project into one of three project classes:

- **Development projects** are those for providing:
  - an adequate supply capacity and/or maintaining an acceptable or prescribed level of customer or system reliability for load growth meeting increased stresses on the system; or
  - enhancing system efficiency such as minimizing congestion on the transmission system and reducing system losses.

- **Connection projects** are those for providing connection of a load or generation customer or group of customers to the transmission system.

- **Sustainment projects** are those for maintaining the performance of the transmission network at its current standard or replacing end-of-life facilities on a "like for like" basis.

It is acknowledged that projects can have elements of development, connection, or sustainment. In these cases, the applicant should identify the proportional make-up of the project, and then classify the project based on the predominant driver.

An investment in the Network may be required in any of these three project classifications. Network facilities are comprised of network stations and the transmission lines connecting them.

b) Project Categorization

The categorization stage identifies the project need as:

- **Non-discretionary** – a "must do" project, the need for which is determined beyond the control of the applicant ("Non-discretionary"), or
- **Discretionary** – the need is determined at the discretion of the applicant ("Discretionary").

The purpose of project categorization is to distinguish whether the project need is **beyond** the control of the ("Non-discretionary") or **at the discretion** of the Applicant ("Discretionary").

Non-discretionary projects may be triggered or determined by such things as:

- mandatory requirement to satisfy obligations specified by regulatory organizations including NPCC/NERC (the designated ERO in the future) or by the IESO;
- a need to connect new load (of a distributor or large user) or new generation (connection);
- a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
- projects identified in a Board or provincial government approved plan;
- projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
- a need to comply with direction from the Ontario Energy Board in the event it is determined that the transmission system's reliability is at risk.

Discretionary projects are proposed by the applicant to enhance the transmission system performance, benefiting its users. Projects in this category may include:

- projects to reduce transmission system losses;
- projects to reduce congestion;
- projects to build a new or enhance an existing interconnection to increase generation reserve margin within the IESO-controlled grid, beyond the minimum level required;
- projects to enhance reliability beyond a minimum standard; and
- projects which add flexibility to the operation and maintenance of the transmission system.

4. Evidence in Support of Need

The reasons that a project is necessary must be identified. The basic form for such evidence should be cost-benefit analyses, if applicable, of various options. The Board expects that Applicants will present:

- the preferred option (i.e. the proposed project); and
- alternative options.

It should be recognized, however, that the Board will either approve or not approve the proposed project (i.e. the preferred option). It will not choose a solution from among the alternative options. The applicant should present the smallest number of alternatives consistent with conveying to the Board the major solution concepts available to meet the same objectives that the preferred option meets.

When providing evidence on the need for the applied-for project, support may arise from a comparison with alternative possible projects. Where a proposed project is best compared to other viable transmission alternatives, the comparison should include "doing nothing".

Where the applicant lists the benefits of a leave to construct project as avoiding non-transmission alternatives such as a peaking generation facility or a "must run" generation requirement, it is helpful for the applicant to include corroborative evidence from the IESO or the OPA regarding the Applicant's quantitative evaluation of such a benefit. In any event, this evidence is required to support the need for the project.

The applicant is expected to also compare the alternatives versus the preferred option along various risk factors including, but not limited to:

- financial risk to the applicant;
- inherent technical risks;
- estimation accuracy risks; and
- any other critical risk that may impact the business case supporting the proposed project.

If the proposed project alternatives are expected to have significant qualitative benefits that cannot reasonably be quantified, evidence about these qualitative benefits should be provided. These benefits may be taken into account in ranking the alternatives. Incorporating qualitative criteria may result in a different ranking of projects compared to the ranking based on quantitative benefits and costs alone. For example, a project may be compared on the basis of its degree of disruption to property owners (least, more and most disruptive).

In addition to the evidence regarding the need for the project, the Applicant must address how it proposes to accomplish the project including the identification of relevant options.

For connection projects, in addition to the cost benefit analysis, the applicant must supply specific information on the nature and magnitude of the network impacts. Certain connection projects may require network reinforcement in order to proceed. A description of the additional information requirements in such cases is provided in Appendix 4 -A to this Chapter. Some of these requirements could affect an evaluation of projects and this should be taken into account.

Where an applicant attributes to a proposed project market efficiency benefits such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project.

Evidence of Need in Non-discretionary Projects

In the case of a non-discretionary project, the preferred option should establish that it is a better project than the alternatives. The applicant need not include "doing nothing" as an alternative since this alternative would not meet the need. One way for a rate-regulated applicant to demonstrate that a preferred option is the best option is to show that it has the highest net present value as compared to the other viable alternatives. However, this net present value need not be shown to be greater than zero. In contrast, in the case of a discretionary project, "doing nothing" would count as a viable option.

External Need Factors

In some cases, a discretionary or non-discretionary project's need is driven by factors external to the applicant, such as the need to satisfy an IESO requirement or to serve an incremental customer load. Where the applicant identifies a customer or agency (such as the IESO or the OPA) as the driver behind a project:

- It is the Applicant's responsibility to include evidence from that customer or agency as part of the evidence in the application.
- The customer or agency must be prepared to provide witnesses as needed to support the filed evidence if an oral hearing is held.
- It is not sufficient for the applicant to state that the customer or agency has established the need for the project; the Board must be able to test that assertion.
- The Board expects the applicant to work with that external party in the development of the required evidence. The external party will often be the IESO and/or the OPA, although the additional evidentiary requirement could apply to any external party on whom the applicant has relied for the justification of the need for the project.

The evidence may include:

- written material prepared by the customer or agency specifically addressing the proposed project, and,
- a list identifying the key driving factors of the evidence justifying the project need, and the party (e.g. the applicant, the IESO, or the OPA) which has prepared the evidence to justify a given key driving factor.

5. Project Shared Costs

Where there are costs which are shared between rate regulated and non rate-regulated parties, proponents must provide details of project costs to the rate-regulated party. Applicants should provide details covering:

- labour - including a breakdown by facility installations;
- materials - including a breakdown of all facility costs;
- cost of similar projects constructed by the applicant or by other entities for baseline cost comparisons covering:
    - in-service year of the comparator project, and
    - similarities and differences in terms of voltage level, type of towers, type of terrain, etc.
- acquisition of land use rights, and land acquisition including permanent and working easements, survey and appraisals, legal fees, crop and damage compensation;
- direct and indirect overheads broken down by facility installation; and,
- allowance for funds used during construction ("AFUDC").

6. Transmission Rate Impact Assessment

The Board requires information relating to the rate impacts anticipated from transmission investments. Information should cover the short-term impacts as well as long-term impacts of the proposed project.

7. Establishment of Deferral Accounts

The Board would consider applications by licensed transmitters requesting that the Board include with its grant for leave to construct, the establishment of a deferral account (under the Uniform System of Accounts) to track the project construction costs and that such accounts would be reviewed for prudence and inclusion in rate base in a future rate proceeding.

Exhibit C: Project Planning

The applicant must provide the Board with time estimates for construction and service dates, including:

- the critical path and time frame for the completion of construction and operational start-up of the proposed facilities;
- any aspects of the start-up of operation relative to the introduction of the new or

additional market demands on the transmission system;

- the estimated schedule (time of year and duration) for each of the major construction activities and the implications of critical constraints such as:
  - delay in start of construction due to failure to obtain timely approvals;
  - prolonged adverse weather conditions;
  - availability of qualified contractors and/or skilled trades persons;
  - construction windows due to environmental constraints; and,
  - the projected and contractual in-service date for the facilities.

Exhibit D: Project Details:

This section of the application must provide detailed information on the project, focussing on identifying project design features and procedures that will ensure the safe and reliable operation of the proposed facilities. These design specifications should demonstrate compliance with the technical requirements as specified in the TSC.

The route of the line is critical because the Board will only provide leave to construct for a specific route. Any material deviations to the approved route following Board approval will invalidate the leave to construct.

This exhibit should include:

- Descriptions of the physical design, including:
  - a section by section description of the physical form of the line;
  - transmission line details, including conductor type, ratings;
  - transmission structure description including the variety of towers;
  - transmission cable burial information and cross-section; and
  - transformer and switching stations
- Maps indicating:
  - the route of the line and the Lot number and Concession number through or adjacent to which the line runs;
  - the plan of each section of the transmission line in relation to the description and indicating clearances to the land profile or, where buried, in relation to the surface; and
  - the right-of-way dimensions and an indication of where the route crosses privately owned land.

Exhibit E: Design Specifications and Operational Data

Operational details:

The application must provide the following details on the planned operation of the transmission line including:

- the control stations
- monitoring and metering locations

Codes, Standards and Regulations:

The application must provide a description of any applicable codes, standards, and regulations that are applicable to the project. It must also provide engineering details with respect to any special design features, which may influence the construction and in-service schedule and to demonstrate that the proposed transmission facilities will be safe and reliable. Specifically, a table should be provided which indicates:

- a list of any documents, including permits, licences and approvals from other agencies which must be received before the project can be implemented;
- the reason the document is required; and
- the location of the various physical sections and components of the project.

Exhibit F: Land Matters

The application must include accurate documentation that demonstrates compliance with legislative requirements and respects the rights of affected parties, including:

- land easements required
- land rights, and
- the land acquisition process.

A description of the land area required including:

- the width(s) of any right-of-way required on new and/or existing easements;
- the location and ownership of land with existing easements and of any new easements or land use rights that will be required; and
- the need and amount of additional temporary working rights required at designated locations such as crossings of rivers, roads, railways, drains and other facilities.

A description of the land rights required must be provided including:

- the type of land rights proposed to be acquired for the project and related facilities (e.g. permanent easement, fee simple);
- the nature and relative proportions of land ownership along the proposed route (i.e., freehold, Crown or public lands); and,
- where no new land rights are required, a description of the existing land rights that allow for the project.

A description of the land acquisition process including:

- identification of the properties and the property owners and/or tenants affected by the proposed construction (landowners line list);
- the extent of notification to landowners regarding the routing of the new facility, the environmental assessment and the facility application;
- the applicant's plan for acquiring new easements or for amending existing easements; and the progress achieved to date with affected landowners, any concerns, or objections registered by affected landowners and municipalities with respect to the proposed construction, and the resolution of these concerns.

A copy of, or a reference for, each of the following forms must be submitted where applicable and where an up-to-date copy is not already on file with the Board:

- the option for easement form;
- the working rights agreement form;
- the easement agreement form;
- the damage release form; and,
- a copy of any correspondence with affected landowners outlining changes in company policy with respect to land acquisitions.

Exhibit G: Community and Stakeholder Consultation

The Board expects applicants will consider stakeholder consultation for all projects. Applicants are responsible for justifying the extent of consultation carried out for each application. The following information should be provided within the application:

- principles and goals of the consultation program;
- design details of the consultation program; and,

- the results of the consultation carried out, including how public input influenced the design, construction, or operation of the project; or,
- an explanation if no consultation was pursued.

As a result of the limits on the Board's jurisdiction imposed by subsection 96(2), the Board does not itself consider issues relating to the Crown's duty to consult with Aboriginal peoples in section 92 applications[8]. However, applicants should be aware that the proposed project may well give rise to duty to consult issues that will be dealt with in other forums (for example, the environmental assessment).

Exhibit H: System Impact Assessment

The IESO Connection Assessment and Approval process identifies the detailed procedures to be followed by applicants who wish to connect or modify a connection to the IESO-administered grid. The IESO evaluates the design of the project and its impact on integrated power system reliability, and identifies any transmission facility enhancements required. IESO requirements must be fulfilled in addition to those listed here.

Exhibit I: Customer Impact Assessment

The Applicant, including a rate-regulated transmitter if it is the Applicant, is required to include in its evidence a Customer Impact Assessment (CIA) report, as required by the TSC.

The CIA report is to be completed by the rate-regulated transmitter to which the Applicant's transmission facilities are connected. A transmitter shall carry out a CIA for any proposed new or modified connection where:

- the connection is one for which the IESO's connection assessment and approval process requires a system impact assessment; or
- the transmitter determines that the connection may have an impact on existing customers.

A transmitter may decide not to carry out a CIA for any proposed new connection or modification that is not subject to a system impact assessment. In such a case, the transmitter would notify existing customers in the vicinity, advising them of the proposed new connection or modification and of the transmitter's decision not to carry out a CIA on the basis that no customer impact is expected.

[8] See, for example, the Board's Decision on Questions of Jurisdiction and Procedural Order No. 4 in EB-2009-0120, issued November 18, 2009.

A transmitter would provide each affected customer with a new available fault current level at its delivery point(s). This would allow each customer to take, at its own expense, action to upgrade its facilities as may be required to accommodate the new available fault current level up to the maximum allowable fault levels set out in Appendix 2 of the TSC.

Appendix 4-A

Connection Projects Requiring Network Reinforcement

For review of connection projects the Board requires submission of evidence to cover various aspects including:

- Transmission System Impact and Network Reinforcement;
- Cost Responsibility for Network Reinforcement; and
- Implementation of Required Network Upgrades

Transmission System Impact and Network Reinforcement

The applicant must supply information on the nature and magnitude of any impact of the proposed connection facility on the transmission system. Normally the IESO addresses and provides high level assessment of such impacts in the System Impact Assessment report performed by the IESO as set out in the IESO's Connection Assessment and Approval process.

This information will not on its own be determinative of the decision on leave to construct in these applications as the cost responsibility of line connection investments are addressed fully in the Transmission System Code (TSC) and the applicant is responsible for demonstrating compliance with the TSC.

However, the Board may determine that a transmitter(s) needs to apply for a leave to construct to make the required network upgrades triggered by the proposed connection project. If a leave to construct is necessary, the Board may wish to invite the transmitter(s) to make the needed applications at the same time, or immediately following, the application of the connecting customer.

The nature and magnitude of other network impacts resulting from the proposed investment must be identified e.g. changes in generation dispatch and transmission line losses.

Cost Responsibility for Network Reinforcement

Section 6.3.5 of the TSC states that "A transmitter shall not require any customer to make a capital contribution for the construction of or modifications to the transmitter's network facilities that may be required to accommodate a new or modified connection. If exceptional circumstances exist so as to reasonably require a customer to make a capital contribution for network construction or modifications, the transmitter or any other interested person may apply to the Board for direction."

Transmitters and other interested parties may apply to the Board for direction on the existence of “exceptional circumstances” requiring the connecting customer to make a capital contribution for network investments triggered by their proposed line connection. The onus is on the transmitter and other interested parties to establish to the Board’s satisfaction that “exceptional circumstances” exist.

Implementation of Required Network Upgrades

When the proposed investment project necessitates network upgrades to comply with the TSC and other industry standards and codes, the nature, magnitude and impact of the necessary upgrades must be identified e.g. changes in generation dispatch and transmission line losses).

A key objective of the OEB in these contexts is early identification of the magnitude of any upstream network impacts resulting from a connection investment. This early identification will enable the OEB to determine if relevant rate-regulated transmitters should be invited to pursue leave to construct applications. A related objective is to enable any person to make application to the Board under section 6.3.5 of the TSC for a finding that exceptional circumstances apply, and that the connection proponent should therefore bear some portion of the cost responsibility for the resulting network upgrades that are required.

Chapter 5 Prior to the approval of an Integrated Power System Plan: Filing requirements for the approval of a capital budget for a transmission project in a rate application or for the approval of projects under section 92 of the OEB Act

The information previously in this chapter has been consolidated into Chapter 4.

Ontario Energy Board

Commission de l’énergie de l’Ontario

Ontario Energy Board

Chapter 5 of the Filing Requirements For Electricity Transmission and Distribution Applications

Vacant

This page was intentionally left blank

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario Energy Board

Chapter 6 of the Filing Requirements For Electricity Transmission and Distribution Applications

Vacant

This page was intentionally left blank

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2006-0327

Ontario Energy Board

Filing Requirements for Service Area Amendment Applications

To be included as Chapter 7
of the Filing Requirements for Electricity
Transmission and Distribution Applications

(March 12, 2007)

CHAPTER 7: FILING REQUIREMENTS FOR SERVICE AREA AMENDMENT APPLICATIONS

TABLE OF CONTENTS

This chapter provides information to guide distributors in filing applications that involve service area amendments ("SAA").

A SAA is an amendment to Schedule 1 of a distributor's licence. Schedule 1 of a distributor's licence is the part of the licence that defines the distributor's service area. Section 74(1) of the Act allows the Board to amend distributors' licences where the amendment is in the public interest.

The development of SAA filing requirements is guided by the Board's objectives in electricity namely, economic efficiency, consumer protection and the maintenance of a financially viable electricity industry. The filing requirements are also based on the general principles articulated in the Board's Decision on the Combined Service Area Amendments Proceeding ("RP-2003-0044").

In RP-2003-0044, the Board articulated certain principles on consumer protection and economic efficiency in relation to SAAs. One such principle is that economic efficiency and the protection of consumer interests will be achieved through the rational optimization of existing distribution systems.

The RP-2003-0044 decision also provided the Board's view that applications that are consented to by the contiguous distributors and individual customers involved can be processed expeditiously. While all SAA applications would need to address the principles outlined in the RP-2003-0044 decision (i.e., economic efficiency, impacts on distributors and their customers, and customer preference), the Board stated that the level of detail required for consent applications would be less than that required for contested applications.

The information in sections 7.1 to 7.4 must be provided for all SAA applications. The information requested under section 7.5 must be provided for contested SAA applications (i.e., applications where the applicant has not been able to obtain the consent of all affected parties).

For the purposes of these filing requirements, it is assumed that the applicant is a distributor who requires a service area amendment to its licence. Some of the information required by these filing requirements may be third-party information that the applicant does not have in its possession. In such cases, the applicant will be expected to use its best efforts to obtain the third-party information and comply with all provisions of these filing requirements. The Board may continue to process the SAA application notwithstanding the fact that the third-party information is not included with the filed SAA application. However, the Board will not determine the SAA application until all of the required information is filed during the course of the proceeding regardless of whether the information is provided by the applicant, the incumbent distributor (i.e., the distributor that currently has the region that is the subject of the SAA application in its service area), the customer, or other relevant third party. In appropriate cases, the Board may direct the relevant third parties to file the information required by the Board.

The filing requirements set out in this chapter do not limit the discretion of the Board in terms of what information and evidence it may wish to see during the course of a proceeding. The filing requirements set out in this chapter are also not intended to limit the applicants in terms of what information they may wish to file in addition to the information required by this chapter.

7.1 Basic Facts

The information in this section is required to provide the Board with basic information about the application and an understanding of the details of the proposed SAA.

General

7.1.1 Provide the contact information for each of the following persons:

(a) the applicant;

(b) the incumbent distributor;

(c) every affected customer, landowner, and developer in the area that is the subject of the SAA application;

(d) any alternate distributor other than the applicant and the incumbent distributor, if there are any alternate distributors bordering on the area that is the subject of the SAA application; and

(e) any representative of the persons listed above including, but not limited to, a legal representative.

Contact information includes the name, postal address, telephone number, and, where available, the email address and fax number of the persons listed above.

7.1.2 Indicate the reasons why this amendment should occur and identify any load transfers eliminated by the proposed SAA.

Description of Proposed Service Area

7.1.3 Provide a detailed description of the lands that are the subject of the SAA application. For SAA applications dealing with individual customers, the description of the lands should include the lot number, the concession number, and the municipal address of the lands. The address should include the street number, municipality and/or county, and postal code of the lands. For SAA applications dealing with general expansion areas, the description of the lands should include the lot number and the concession number of the lands, if available, as well as a clear description of the boundaries of the area (including relevant geographical and geophysical features).

7.1.4 Provide one or more maps or diagrams of the area that is the subject of the SAA application. The maps or diagrams must identify the following information:

a) the borders of the applicant's service area;

b) the borders of the incumbent distributor's service area;

c) the borders of any alternate distributor's service area, if applicable;

d) the territory surrounding the area for which the applicant is making the SAA application;

e) the geographical and geophysical features of the area including, but not limited to, rivers and lakes, property borders, roads, and major public facilities; and

f) the existing facilities supplying the area that is the subject of the SAA application, if applicable, as well as the proposed facilities which will be utilized by the applicant to supply the area that is the subject of the SAA application (Note: if the proposed facilities will be utilized to also provide for expansion of load in the area that is the subject of the SAA application, identify that as well).

Distribution Infrastructure In and Around the Proposed Amendment Area

7.1.5 Provide a description of the proposed type of physical connection (i.e., individual customer; residential subdivision, commercial or industrial development, or general service area expansion).

7.1.6 Provide a description of the applicant's plans, if any, for similar expansions in lands adjacent to the area that is the subject of the SAA application. Provide a map or diagram showing the lands where expansions are planned in relation to the area that is the subject of the SAA application.

7.2 Efficient Rationalization of the Distribution System

The proposed SAA will be evaluated in terms of rational and efficient service area realignment. This evaluation will be undertaken from the perspective of economic (cost) efficiency as well as engineering (technical) efficiency.

Applicants must demonstrate how the proposed SAA optimizes the use of existing infrastructure. In addition, applicants must indicate the long term impacts of the proposed SAA on reliability in the area to be served and on the ability of the system to meet growth potential in the area. Even if the proposed SAA does not represent the lowest cost to any particular party, the proposed SAA may promote economic efficiency if it represents the most effective use of existing resources and reflects the lowest long run economic cost of service to all parties.

7.2.1 In light of the above, provide a comparison of the economic and engineering efficiency for the applicant and the incumbent distributor to serve the area that is the subject of the SAA application. The comparison must include the following:

a) the location of the point of delivery and the point of connection;

b) the proximity of the proposed connection to an existing, well-developed electricity distribution system;

c) the fully allocated connection costs for supplying the customer (i.e., individual customers or developers) unless the applicant and the incumbent distributor provide a reason why providing the fully allocated connection costs is unnecessary for the proposed SAA (Note: the Board will determine if the reason provided is acceptable).

d) the amount of any capital contribution required from the customer;

e) the costs for stranded equipment (i.e., lines, cables, and transformers) that would need to be de-energized or removed;

f) information on whether the proposed SAA enhances, or at a minimum doses not decrease, the reliability of the infrastructure in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application over the long term;

g) information on whether the proposed infrastructure will provide for cost-efficient expansion if there is growth potential in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application; and

h) information on whether the proposed infrastructure will provide for cost-efficient improvements and upgrades in the area that is the subject of the SAA application and in regions adjacent to the area that is the subject of the SAA application.

7.3 Impacts Arising from the Proposed Amendment

Description of Impacts

7.3.1 Identify any affected customers or landowners.

7.3.2 Provide a description of any impacts on costs, rates, service quality, and reliability for customers **in** the area that is the subject of the SAA application that arise as a result of the proposed SAA. If an assessment of service quality and reliability impacts cannot be provided, explain why.

7.3.3 Provide a description of any impacts on costs, rates, service quality, and reliability for customers of any distributor **outside** the area that is the subject of the SAA application that arise as a result of the proposed SAA. If an assessment of service quality and reliability impacts cannot be provided, explain why.

7.3.4 Provide a description of the impacts on each distributor involved in the proposed SAA. If these impacts have already been described elsewhere in the application, providing cross-references is acceptable.

7.3.5 Provide a description of any assets which may be stranded or become redundant if the proposed SAA is granted.

7.3.6 Identify any assets that are proposed to be transferred to or from the applicant. If an asset transfer is required, has the relevant application been filed in accordance with section 86 of the Act? If not, indicate when the applicant will be filing the relevant section 86 application.

7.3.7 Identify any customers that are proposed to be transferred to or from the applicant.

7.3.8 Provide a description of any existing load transfers or retail points of supply that will be eliminated.

7.3.9 Identify any new load transfers or retail points of supply that will be created as a result of the proposed SAA. If a new load transfer will be created, has the applicant requested leave of the Board in accordance with section 6.5.5 of the Distribution System Code ("DSC")? If not, indicate when the applicant will be filing its request for leave under section 6.5.5 of the DSC with the Board. If a new retail point of supply will be created, does the host distributor (i.e., the distributor who provides electricity to an embedded distributor) have an applicable Board approved rate? If not, indicate when the host distributor will be filing an application for the applicable rate.

Evidence of Consideration and Mitigation of Impacts

7.3.10 Provide written confirmation by the applicant that all affected persons have been provided with specific and factual information about the proposed SAA. As part of the written confirmation, the applicant must include details of any communications or consultations that may have occurred between distributors regarding the proposed SAA.

7.3.11 Provide a letter from the incumbent distributor in which the incumbent distributor indicates that it consents to the application.

7.3.12 Provide a written response from all affected customers, developers, and landowners consenting to the application, if applicable.

7.3.13 Provide evidence of attempts to mitigate impacts where customer and/or asset transfers are involved (i.e., customer rate smoothing or mitigation, and compensation for any stranded assets).

7.4 Customer Preference

The Board, in the RP-2003-0044 decision, stated that customer preference is an important, but not overriding consideration when assessing the merits of an SAA.

7.4.1 An applicant who brings forward an application where customer choice may be a factor must provide a written statement signed by the customer (which includes landowners and developers) indicating the customer's preference.

7.5 Additional Information Requirements for Contested Applications

If there is no agreement among affected persons regarding the proposed SAA, the applicant must file the additional information set out below.

7.5.1 If the application was initiated due to an interest in service by a customer, landowner, or developer, evidence that the incumbent distributor was provided an opportunity to make an offer to connect that customer, landowner, or developer.

7.5.2 Evidence that the customer, landowner, or developer had the opportunity to obtain an offer to connect from the applicant and any alternate distributor bordering on the area that is the subject of the SAA application.

7.5.3 Actual copies of, as well as a summary of, the offer(s) to connect documentation (including any associated financial evaluations carried out in accordance with Appendix B of the Distribution System Code). The financial evaluations should indicate costs associated with the connection including, but not limited to, on-site capital, capital required to extend the distribution system to the customer location, incremental up-stream capital investment required to serve the load, the present value of incremental OM&A costs and incremental taxes as well as the expected incremental revenue, the amount of revenue shortfall, and the capital contribution requested.

7.5.4 If there are competing offers to connect, a comparison of the competing offers to connect the customer, landowner, or developer.

7.5.5 A detailed comparison of the new or upgraded electrical infrastructure necessary for each distributor to serve the area that is the subject of the SAA application, including any specific proposed connections.

7.5.6 Outage statistics or, if outage statistics are not available, any other information regarding the reliability of the existing line(s) of each distributor that are proposed to supply the area that is the subject of the SAA application.

7.5.7 Quantitative evidence of quality and reliability of service for each distributor for similar customers in comparable locations and densities to the area that is the subject of the SAA application.