Ontario Energy Board

Commission de l’énergie de l’Ontario

Ontario

Ontario Energy Board

Filing Requirements
For
Electricity Distribution Rate Applications

Last Revised on July 17, 2013

(Originally issued on November 14, 2006)

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Ontario

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications

Chapter 1

Overview

July 17, 2013

Chapter 1 Overview

This document provides information about the filing requirements for electricity distribution rate applications. It has been designed to provide direction to applicants, and it is expected that applicants will file applications consistent with the filing requirements. If circumstances warrant, the Board may require an applicant to file evidence in addition to what is identified in the filing requirements. The filing requirements are designed to ensure that an appropriate base level of information is either produced or at least considered for its applicability to the applicant's circumstance.

The filing requirements apply only to distributors. Unless specifically identified, the words "utility", "utilities", "applicant" or "applicants" in this document refer to distributors.

Transmitters should consult the June 28, 2012 edition of the Chapter 1 and 2 filing requirements for guidance on rate applications. The Board will issue further instructions to transmitters in due course.

References to a "party" refer to the applicant, Board staff and any registered intervenors.

Renewed Regulatory Framework for Electricity

On October 18, 2012, the Board released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") which introduced three rate-setting methods: (1) 4th Generation IR, (2) Custom IR and (3) Annual IR Index.

Chapters Included in this Filing Requirement Document

The Filing Requirement document sets out the information that must be included in a rate application.

Chapter 1 outlines generic procedural matters and certain expectations of the Board from parties participating in the adjudication process pursuant to Chapters 2, 3 and 5.

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 distribution company.

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 3 includes specific guidance on requirements related to both the 4th Generation IR and Annual IR Index approaches.

Chapter 5, which was issued by the Board on March 28, 2013, "*Consolidated Distribution System Plan Filing Requirements,*" sets out filing requirements for consolidated distribution system plans. These outline the information required by the Board to assess a distributor's planned expenditures on distribution system and other infrastructure. Distributors must review this Chapter and its cover letter, regardless of which rate-setting option they are contemplating, to ensure that they are meeting the specific requirements of this Chapter, which are applicable to all three rate-setting methods listed above.

Completeness and Accuracy of an Application

An application to the Board by a regulated company must provide sufficient detail to enable the Board to make a determination as to whether the proposals are reasonable. The onus is on the applicant to substantiate the need for and reasonableness of the costs that are the basis of proposed new rates. A clearly written application that demonstrates the need for the proposed rates, complete with sufficient justification for those rates, is essential to facilitate an effective regulatory review and a timely decision. The filing requirements provide the minimum information that applicants must file for a complete application. However, applicants should provide any additional information that is necessary to justify the approvals being sought in the application.

The Board's examination of an application and 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 essential.

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 all of the applicable filing requirements.

Applicants must also be cognizant of the need for accuracy and consistency of the information and data presented in their applications. A quality application has information and data that is consistent across all exhibits, appendices and models. If an application does not meet all of these requirements or if there are inconsistencies identified in the information or data presented, the Board may return the application unless satisfactory explanations for missing or inconsistent information have been provided.

Certification of Evidence

Applications filed with the Board must be certified by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of his/her knowledge.

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 in later stages of 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(s) revised.

Interrogatories

The Board is aware of the number of interrogatories that the regulatory review process can generate. The Board advises applicants to consider the clarity, completeness and accuracy of their evidence in order to reduce the need for interrogatories. The Board also advises parties to carefully consider the relevance and materiality of information before requesting it through interrogatories.

It is the Board's expectation that parties will not engage in detailed exploration of items that do not appear to be material. For rate applications, parties should be guided by the materiality thresholds documented in Chapters 2 and 3 in assessing what is material. The Board will consider at the cost award stage of the process whether or not specific intervenors have engaged in excessively detailed exploration of non-material issues and may reflect this in the cost award decision.

Where an applicant is requested by a party to file information that the applicant believes is not relevant to any matter at issue in 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 or exhibit as applicable and, for responses, by party within each issue or exhibit, and within each exhibit by topic. For example, all interrogatory responses on test year capital budget arising from an application under Chapter 2 must be grouped together by party. 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 (or by section numbers for chapter 3 which is not arranged in exhibits). This process is also contemplated in Rule 29 of the *Rules of Practice and Procedure* and applies to all interrogatories.

Interrogatory Nomenclature

The Board will issue a list of acronyms for each party to the proceeding prior to the commencement of the interrogatory period. For instance, if the School Energy Coalition was an intervenor in a proceeding, it may be assigned the acronym “SEC” while Board staff would be assigned “Staff”.

When parties are submitting interrogatories, a continuous numbering system must be used to facilitate subsequent referencing of the interrogatories. An illustration of the continuous numbering system for Board staff interrogatories is as below.

The first staff interrogatory would be numbered **1-Staff-1**. The first reference to number ‘1’ indicates that this is an interrogatory related to Issue 1 on the Board-approved Issues List. The “Staff” reference is the acronym for Board staff. The second reference to number ‘1’ means that it is the first Board staff interrogatory.

The next Board staff interrogatory for this issue would be numbered **1-Staff-2**. If these were the only two Board staff interrogatories for this issue, the next interrogatory would be numbered **2-Staff-3**. While this interrogatory is the first for Issue 2, the numbering system does not revert to ‘1’. This interrogatory is numbered as the third overall interrogatory due to the continuous numbering approach described above.

For applications without Board-approved issues lists, the Filing Requirement exhibit numbers (or section numbers for chapters that are not arranged in exhibits) must be used. As an example, the first Board staff interrogatory related to rate base in Chapter 2, which is Exhibit 2, would be **2-Staff-15** (assuming that under Exhibit 1 there had been 14 Board staff interrogatories).

If there is a supplemental round of discovery through interrogatories, the numbering sequence continues, with each interrogatory number appended with an “s”. For example, **5-Staff-37s** would refer to the 37^{th} interrogatory issued by Board staff in the proceeding, in this case pertaining to Exhibit 5 (Cost of Capital) of Chapter 2 and in a supplementary round of interrogatories.

Applicants must ensure that the electronic version of their interrogatory responses is bookmarked by issue, exhibit, topic or section, as applicable.

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’s expectation is that applicants will make every effort to file material contained in an application publicly in order to ensure the transparency of the review process. 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. Applicants considering the need for confidential filing of material are expected to review and follow the Practice Direction:

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. Parties must ensure that filings for which they intend to request confidential treatment are clearly relevant to any matter at issue in the proceeding, whether the information is being filed as part of an application, as an exhibit 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 any information requested by interrogatories in relation to confidential filings given the administrative issues associated with the management of those filings.

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Filing Requirements For
Electricity Distribution Rate Applications

Chapter 2

Cost of Service

July 17, 2013

Table of Contents

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

2.0 Introduction

On October 18, 2012, the Board released its *Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") which introduced three rate-setting methods: (1) 4th Generation IR, (2) Custom IR and (3) Annual IR Index. The 4th Generation IR option consists of a cost of service ("cost of service" or "CoS" or "rebasing")[1] followed by four years of incentive regulation mechanism ("IRM") adjustments. This chapter relates to the cost of service rate application. Filing requirements for IRM rate applications and the Annual IR Index option 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 those data.

The filing requirements contained in this Chapter (and Chapter 5) outline all the relevant information necessary for a complete cost of service-based application. The various appendices referenced in this chapter are linked to each of the sections in Chapter 2 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 section 2.10.3 Revenue-to-Cost Ratios). These appendices are available in Microsoft Excel format on the Board's web site and must be completed by applicants and filed as part of a CoS application.

The models issued by the Board, including those contained in the appendices to this chapter, are provided to assist the applicant in filing a rate application, and to provide consistent formatting for all distributors for greater efficiency of the review process. An application to the Board is the applicant's responsibility and the Board expects that the application will be complete and accurate. Likewise, the applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The applicant is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models as well as any changes that the applicant may have made to the models to address its own circumstances. Given the variety of different circumstances to be

[1] The Board considers cost of service and rebasing to be the same and therefore these terms are used interchangeably.

considered, the use of a Board model does not necessarily mean that the Board will approve the results.

Applicants should review Chapter 1 of this document, which provides an overview of the Board's expectations on certain generic matters, such as the completeness and accuracy of an application, the exploration of non-material items, and confidential filings.

2.1 Cost of Service Application in Advance of Scheduled Application

In the RRFE Report, the Board outlined the transition plan which it had established to facilitate the adoption of the three new rate-setting methods. Distributors should consult Section 5.2 "Transition" of the RRFE Report to ensure that their planned applications are consistent with this transition plan.

Those distributors who are within the term of their current 3rd Generation IR (in other words are scheduled to rebase for January 1, 2015 rates or later) and are opting for the 4th Generation IR option will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR term. Distributors can also opt for the Custom IR or the Annual IR Index methodologies. Distributors opting for 4th Generation IR and planning to file a cost of service application earlier than scheduled, must meet the threshold for early rebasing established in the Board's letter of April 20, 2010 .

2.2 Seeking Approval to Align Rate Year with Fiscal Year

Distributors seeking an approval to align their rate year with their fiscal year (i.e. January 1) must provide a discussion of the rationale for the proposed alignment. If a January 1st effective date is being requested as well, 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 General Requirements

The basic format of an application for a forward test year cost of service filing must include 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 standard 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 the Chapter 2 Appendices, tab 3.

Other exhibits may also be included in an application to document other proposals for which the applicant is seeking Board review and approval.

Applicants may refer to the Chapter 2 Appendices, tab 4 for a list of key references that underpin many of the filing requirements of this chapter.

The items 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.
- Documents are to be provided in bookmarked and text-searchable Adobe PDF format; and
- Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical.

If a distributor updates its evidence throughout the proceeding, the distributor must ensure that the following models, among others, are updated as applicable and the revised figures reconcile to each other:

- Revenue Requirement Work Form;
- Chapter 2 Appendices;
- EDDVAR Continuity Schedule;

- Income Tax PILs Workform;
- Cost Allocation Model;
- RTSR Model; and
- Smart Meter Model.

2.3.1 Integrated Distribution Planning for Eligible Investments to Connect Qualifying Generation Facilities

On March 28, 2013, the Board issued Chapter 5 of its Filing Requirements, "*Consolidated Distribution System Filing Requirements*."

Chapter 5 implements the Board's policy direction on an integrated approach to distribution network planning, as set out in the RRFE Report, and applies to distributors filing cost of service applications for the rebasing of their rates.

For distributor filings going forward, the Board's "*Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence*" will no longer be applicable and such investments will henceforth be reviewed by the Board in the same fashion as other proposed capital expenditures. The funding mechanisms set out in the "*Filing Requirements: Distribution System Plans – Filing Under Deemed Conditions of Licence*" specifically for renewable generation connection and smart grid development will no longer be available after the distributor's first cost of service application containing a complete Chapter 5 distribution system plan.

In addition, no new deferral accounts for these types of expenditures will be established, and existing deferral accounts are expected to be discontinued following the filing of the first cost of service application containing a consolidated capital plan. Distributors filing cost of service applications in 2014 and subsequent years must include proposals for disposition of any existing balances in the deferral accounts.

Distributors yet to file a cost of service application containing a consolidated capital plan pursuant to Chapter 5 will continue to be able to record renewable energy generation costs, smart grid demonstration costs and funding adder revenues (for existing funding adders) in deferral accounts already established for this purpose. Likewise, such distributors may also seek new funding adders for material eligible investments if they are on the 4th generation IR plan as part of their IRM applications, until such time as the first cost of service application containing a consolidated capital plan.

In addition, distributors that have included eligible investments to connect qualifying facilities in their distribution system plans as part of a cost of service application may seek Board approval for investments forecast to enter service beyond the test year for purposes of implementing rate protection pursuant to the legislation. For these future years' investments distributors shall recover only the component associated with rate protection. The remaining component of each investment is treated as any other capital investment made in non-rebasing years.

If "eligible investments" are approved by the Board as defined under Reg. 330/09 under the OEB Act, variance accounts will continue to be used for the purpose of recording actual costs of approved "eligible investments," and revenue received from the IESO pursuant to the provincial pooling mechanism set out in section 79.1 of the OEB Act.

Further information on the requirements to implement recovery from all Ontario ratepayers can be found in section 2.5.2.5.

2.3.2 Accounting Standards

This section provides information on the following accounting standards relevant to the filing of cost of service applications:

International Financial Reporting Standards (IFRS);

Canadian Generally Accepted Accounting Principles (CGAAP);

United States Generally Accepted Accounting Principles (USGAAP); and

Accounting Standards for Private Enterprise (ASPE).

The accounting standard that is used as the basis of the application must be clearly stated. 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 changes in accounting policies must be separately quantified.

2.3.2.1 Modified IFRS Application

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

- *Report of the Board: Transition to IFRS;* dated July 28, 2009;
- *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
- *OEB Accounting Policy Changes for Accounts 1575 and 1576*; dated June 25, 2013.

For those applicants that have adopted IFRS for financial reporting purposes or will adopt IFRS for financial reporting purposes effective January 1, 2014 or earlier, cost of service applications must be filed on the basis of modified IFRS ("MIFRS").

2.3.2.2 CGAAP Application

Utilities have the option of filing a CGAAP application if the utility chooses not to adopt IFRS for financial reporting purposes until January 1, 2015.

Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory in 2013 for all distributors that have not yet made these changes, and therefore all applications for 2014 rates should reflect that these changes were made in 2012 or 2013.

2.3.2.3 USGAAP or ASPE Application

The Board requires a utility that adopts USGAAP or ASPE, 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 governing securities legislation to report financial information using that standard (if applicable);
2. a copy of the authorization to use the standard from the corresponding 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.

Per the Board's letter of July 17, 2012, electricity distributors adopting ASPE must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory in 2013 for all distributors that have not yet made these changes, even if there are further options to defer IFRS changeover.

2.4 Exhibit 1. Administrative Documents

The items identified in this section provide the background and summary to the application as filed and are grouped into five sections:

1) Executive Summary;
2) Customer Engagement;
3) Financial information;

4) Materiality thresholds; and
5) Administration.

2.4.1 Executive Summary

This section is the opportunity for the applicant to provide an overview of key elements of its application and its overall business strategy, including a narrative of how its approach supports the four outcomes established by the Board in the RRFE report. As a minimum, this section requires a brief summary of the following items in the application, if applicable.

A. Revenue Requirement

- Service Revenue Requirement requested for the test year;
- Increase/decrease ($ and %) from previously approved service revenue requirement; and
- Schedule of main drivers of revenue requirement changes from the last Board approved year.

B. Budgeting Assumptions

- Economic Overview (such as growth and inflation).

C. Load Forecast Summary

- Load and customer growth (percentage change kWh and change in customer numbers from last Board approved); and
- Brief description of forecasting method(s) used, for customer/connection and consumption/demand.

D. Rate Base and Capital Plan

- Summary of the major drivers of the Distribution System Plan;
- Rate Base Requested for the test year;
- Change in Rate Base from last Board approved ($ and %);
- Capital Expenditures requested for the test year;
- Change in Capital Expenditures from last Board approved ($ and %);
- Summary of any costs requested for renewable energy connections/expansions, smart grid, and regional planning initiatives; and
- Total amount ($) the Applicant seeks to recover from all ratepayers for renewable energy connection costs (Regulation 330/09).

E. Operations, Maintenance and Administration Expense

- OM&A for the test year and the change from last Board approved ($ and %);
- Summary of overall drivers and cost trends;
- Inflation rates used for OM&A forecasts; and
- Total compensation for the test year and the change from last Board approved ($ and %).

F. Cost of Capital

- A statement as to whether or not the Applicant is using the Board's cost of capital parameters; and
- Summary of any deviations from the Board's cost of capital methodology.

G. Cost Allocation and Rate Design

- Summary of any deviations from the Board's cost allocation and rate design methodologies; and
- Summary of any significant changes proposed to revenue to cost ratios and fixed/variable splits, and any proposed mitigation plans.

H. Deferral and Variance Accounts

- Total disposition ($) including split between RPP and non-RPP customers;
- Disposition period; and
- New Deferral and Variance Accounts requested.

I. Bill Impacts

- Summary of total Bill Impacts ($ and %) for all classes for typical customers.

2.4.2 Customer Engagement

The RRFE Report contemplates enhanced engagement between distributors and their customers to provide better alignment between distributor operational plans and customer needs and expectations. The Board expects distributors to provide an overview of customer engagement activities that the distributor has undertaken with respect to its plans and how customer needs have been reflected in the distributor's application.

Distributors should specifically discuss in the application how their customers were engaged in order to determine their needs. This could include references to any communications sent to customers about the application such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers and explain to them how the application serves their needs and expectations and the feedback heard from customers through these engagement activities.

If distributors have not engaged in customer engagement activities, distributors must explain why and if any such activities are planned for in the future.

Distributors will also be expected to file with the Board their response to the matters raised within any letters of comments sent to the Board related to the distributor's application.

The planning elements of customer engagement activities are to be filed as part of the capital plan requirements as required by Chapter 5.

2.4.3 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (i.e. to exclude operations of affiliated companies that are not rate regulated) for which the application has been made, for the most recent three historical years (i.e. two years' statements must be filed, covering three years of historical actuals). If the most recent final historical audited financial statements are not available at the time of filing the application, the draft financial statements must be filed and the final audited financial statements must be provided as soon as they are available;
- 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 must include the identification of any deviations that are being proposed between the Annual Reports/Audited Financial Statements and the regulatory financial statements 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, if applicable;
- Rating Agency Report(s), if available; and
- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings.

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 follows:

- $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.

An applicant may provide additional details beyond the threshold if it determines that this is necessary to provide the Board with information necessary to its review.

Applicants are reminded that the onus is on the applicant to make its case and ensure that the Board has the information it needs to properly assess and deliberate on the application.

2.4.5 Administration

This section must include the following:

- Table of Contents;
- Statement as to who will be affected by the application, and which publication(s) the applicant proposes that notice must appear, whether it is a paid publication or not and the readership and circulation numbers, and the rationale for why the stated publication(s) are appropriate;
- Confirmation of the applicant's internet address for purposes of viewing the application and related documents;
- Contact information. The primary contact for the application may be a person within the applicant's organization other than the primary licence contact (the primary contact's name, address, phone number, fax and email address must all be provided). 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;
- Identification of any legal or other representation for the application;
- The requested effective date;
- Bill impacts (for distributors the distribution only bill impacts as per sub-total A of Appendix 2-W) to be used for the notice of application for a typical residential

customer using 800 kWh per month and for a General Service <50kW customer using 2000 kWh per month, or as applicable;

- Statement as to the form of hearing requested (i.e. written or oral) and an explanation as to the reasons for the applicant's preference;
- List of specific approvals requested and relevant section of legislation. All approvals, including accounting orders (deferral or variance accounts) which the applicant is seeking, must be separately identified in this exhibit and clearly documented in the appropriate section of the application;
- Changes in tax status (e.g. a change from a corporation to a limited partnership) must be disclosed;
- Existing accounting orders and list of any departures from the Uniform System of Accounts including references to Accounting Orders;
- Description of applicant's service area:
    - 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 description of whether the distributor is a host distributor (i.e. distributing 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 distributor must identify the embedded and/or host distributor(s). Partially embedded status must also be clearly identified, including the percentage of load that is supplied through the host distributor;
- Corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include any planned changes in corporate or operational structure (including any changes in legal organization and control) and rationale for organizational change and the estimated cost impact, including the following;
    - Corporate Entities Relationship Chart, showing the extent to which the parent company is represented on the utility company board; and
    - the reporting relationships between utility management and parent company officials.
- Information about the distributor's corporate governance practices, including:

1. Board of Directors
   a. The number of board members and how many are independent[2]. State whether or not there is a policy on the number or proportion of independent directors
   b. A description of what the board of directors does to facilitate its exercise of independent judgment in carrying out its responsibilities.

2. Board Mandate
   The text of the board's written mandate. If the board does not have a written mandate, describe how the board delineates its role and responsibilities.

3. Board Meetings
   A schedule of the meetings of the Board in the current fiscal year (2013 for 2014 CoS filers).

4. Orientation and Continuing Education
   A description of what measures, if any, the board takes to provide continuing education for its directors. If the board does not provide continuing education, describe how the board ensures that its directors maintain the skill and knowledge necessary to meet their obligations as directors.

5. Ethical Business Conduct
   a. A statement as to whether or not the board has adopted a written code for the directors, officers and employees. If the board has adopted a written code:
      i. provide a copy of the code; and
      ii. describe how the board monitors compliance with its code, or if the board does not monitor compliance, explain whether and how the board satisfies itself regarding compliance with its code.

6. Nomination of Directors
   A description of the process by which the board identifies and selects new candidates for nomination to the board of directors.

7. Board Committees
   a. Identification of any committees of the Board.
   b. For each committee identified:
      i. a description of the functions of the committee; and
      ii. the text of the charter for the committee, if one exists.

[2] "Independent" means that the director is not an officer or employee of the distributor or of any of the distributor's affiliates. "Affiliate" has the same meaning as in the *Business Corporations Act (Ontario)*.

c. If there is an audit committee, a statement as to whether or not the members of the committee are (i) independent; and (ii) financially literate.

- 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;
- The Accounting Standard used and when it was adopted;
- A statement identifying all deviations from the Filing Requirements, if any;
- A statement identifying any changes to the methodologies used in previous applications and a description of the changes;
- 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 must clearly indicate how these are being addressed in the current application (e.g. filing of a study as directed in a previous decision);
- Reference to the distributor's Conditions of Service. The distributor does not need to file its Conditions of Service, but must provide a reference to where its Conditions of Service are publicly available (e.g. on the distributor's website), and confirm that this is the current version. If there are changes to its Conditions of Service as a result of approval of the application, the distributor must identify all such changes; and
- All responses to matters raised in letters of comment filed with the Board during the course of the proceeding.

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

This exhibit must include the following sections:

1) Overview;
2) Gross Assets – Property, Plant and Equipment and Accumulated Depreciation;
3) Allowance for Working Capital; and
4) Treatment of Stranded Assets Related to Smart Meter Deployment.

2.5.1.1 Overview

The applicant must provide a complete appendix 2-BA1 or 2-BA2.

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. Alternatively, if an applicant uses a similar method such as calculating the average in service based on the average of monthly values, it must document the methodology used. 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 also 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 opening and closing balances of gross assets and accumulated depreciation that are used to calculate the fixed asset component of rate base must correspond to the respective balances in the fixed asset continuity statements. In the event that the balances do not correspond, the applicant must provide an explanation and reconciliation. This reconciliation must be between the December 31, 2013 and

December 31, 2014 net book value balances reported on the Fixed Asset Continuity Schedule (Appendix 2-BA1 or 2-BA2) and the balances included in the rate base calculation. Examples of adjustments that would be made to the fixed asset continuity schedule balances for rate base calculation purposes are the removal of the amounts for Work in Progress and Asset Retirement Obligations.

A distributor may include smart meter balances in its opening test year property, plant and equipment balances. This may result in opening balances not reconciling to the closing bridge year property, plant and equipment balances. If this is the case, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the smart meter addition was included in the opening test year balances and must reconcile the figures. Distributors must provide the same reconciliation for accumulated depreciation.

The information outlined in Appendix 2-BA1 or 2-BA2 must 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 and Accumulated Depreciation

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 must be accompanied by a description;
- Summary of any incremental capital module adjustment(s), including what was approved and what was spent, if the distributor received approval for an incremental capital module adjustment as part of a previous IRM application;
- Continuity statements must be reconcilable to the calculated depreciation expenses (under Exhibit 4 – Operating Costs) and presented by asset account. Further guidance is included in the appendices.

2.5.1.3 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 must be determined by the split between RPP and non-RPP customers based on actual data and using the most current RPP (TOU) price. The calculation must also reflect the most recent Uniform Transmission Rates approved by the Board (EB-2012-0031), issued on December 20, 2012 and effective January 1, 2013. The calculation should also include the impacts arising from the new Smart Metering Entity charge approved by the Board on March 28, 2013 in its EB-2012-0100/EB-2012-0211 Decision and Order.

- 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 applicant's rate base determination.

2.5.1.4 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.

If not already addressed in a previous Board decision, distributors must file as part of their 2014 application a proposed treatment for the recovery of stranded meters that is in conformity with the approach taken by the Board as follows:

- The total estimated NBV of the stranded meters as of December 31, 2013, or a revised amount calculated in accordance with the above-noted accounting guidance, must be removed from rate base (see Appendix 2-S). The 2014 revenue requirement must not include either a return on capital (i.e. debt cost and return on equity) or depreciation expense associated with the total estimated stranded meter costs removed from rate base;
- The total estimated NBV of the stranded meters must 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;
- The total estimated stranded meter costs must be tracked in “Sub-account Stranded Meter Costs” of Account 1555; and
- The associated recoveries from the separate rate riders must 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 must be proposed to recover the amount of the total estimated stranded costs (i.e. the Stranded Meter Rate Rider). 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, 2013 to be trued-up to actual stranded meter costs when the installation of all smart meters is completed.[3] An adjusting entry must be recorded for this adjustment in the sub-account referenced above. The residual balance (net of

[3] However, most distributors have completed smart meter deployment and TOU billing implementation, and so there should be few, if any, distributors in this situation for 2014 rates applications.

recoveries) must be submitted for review as part of the distributor's next CoS application.

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

If the recovery of stranded conventional meters replaced by smart meters has not been reviewed and approved for recovery in a previous application, the distributor must make a proposal for a Stranded Meter Rate Rider to recover the residual amounts. This applies even for distributors that have had smart meter costs reviewed and approved in stand-alone or IRM applications since their previous cost of service application. A completed Appendix 2-S must also be provided.

2.5.2 Capital Expenditures

Included within this exhibit are the following sections, which will include the Distribution System Plan ("DS Plan") as outlined in Chapter 5.

1) Planning;
2) Required Information;
3) Capitalization Policy;
4) Capitalization of Overhead; and
5) Costs of Eligible Investments for Distributors.

2.5.2.1 Planning

A distributor filing a cost of service rate application for 2014 or subsequent rate years must include in its application a consolidated DS Plan as outlined in Chapter 5.

To facilitate better planning, prioritization and pacing, the RRFE Report concluded that an integrated approach to planning is preferred. This means that all categories of system investments must be consolidated in a distributor's capital expenditure plan, including investments to renew and expand the distribution system, investments identified in a regional planning process, and investments to accommodate the connection of renewable generation or to implement a smart grid. To implement this integrated approach, the Board issued filing requirements and guidance specifically in relation to DS Plans which are incorporated under Chapter 5.

Chapter 5 is to be used by distributors in combination with this Chapter 2. Chapter 5 supersedes the Board's *Filing Requirements: Distribution System Plans - Filing under*

Deemed Conditions of Licence (EB-2009-0397). However, information on the costs of any eligible investments[4] identified pursuant to Chapter 5 for which a distributor is seeking prudence review and approval is to be provided as set out in section 2.5.2.5 below.

2.5.2.2 Required Information

As part of this exhibit, distributors must file a consolidated DS Plan in accordance with Chapter 5 for matters pertaining to asset management, renewable energy generation, smart grid and regional planning. The consolidated DS Plan should be filed as a stand-alone document. Specifically, all elements of the DS Plan must be contained in one document and filed as part of Exhibit 2.

A complete appendix 2-AB must be filed, providing an overall summary of capital expenditures (in the categories identified by Chapter 5) over the past four historical years plus the bridge year and the test year.

Applicants must also provide a complete appendix 2-AA along with the following information about capital expenditures on a project-specific basis. This information is incremental to the requirements in Chapter 5:

- Written explanation of variances, including that of actuals versus the Board-approved amounts for the applicant's last Board-approved cost of service application; 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.

Applicants should also provide the components of other capital expenditures such as for non-distribution activities, including a reconciliation of all capital components to the Total Capital Budget.

2.5.2.3 Capitalization Policy

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

Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP or choosing to adopt ASPE must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes

[4] Eligible investments are capital investments made for the purpose of connecting or enabling the connection of a qualifying generation facility to the distribution system. Rate protection under section 79.1 of the OEB Act may be available for the costs of these investments.

are mandatory in 2013 for all distributors that have not yet made these changes and therefore all applications for 2014 rates should reflect that these changes were made in 2013 (the bridge year).

These accounting changes under CGAAP and ASPE must be implemented consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the Revised 2012 APH.

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

2.5.2.4 Capitalization of Overhead

Regardless of whether the applicant has filed the application under MIFRS, USGAAP, ASPE, or CGAAP, the applicant must complete either Appendix 2-DA or 2-DB depending on the accounting basis on which the application has been filed 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 and after the change.

2.5.2.5 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

For any costs incurred to make eligible investments as described in section 79.1 of the OEB Act and Reg. 330/09 under the Act (and documented in Chapter 5 for distributors), including any facilities forecast to enter service beyond the test year, the distributor must provide a proposal, where applicable, to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per Regulation 330/09, taking into account the Board's Report on the *Framework for Determining Direct Benefits* (EB-2009-0349) (the "Direct Benefits Report").

The component of such investments not eligible for rate protection will be treated similarly to any other new investment undertaken by a distributor and will not be separately tracked. For renewable generation connection investments, distributors can assume the direct benefit percentage to be 17 percent and for renewable enabling improvement investments 6 percent. Distributors would continue to have the option to undertake a more rigorous “detailed” direct benefits assessment based on the criteria set out in the Direct Benefits Report where the distributor believes the standard percentages would not be reflective of the direct benefits.

Appendices 2-FA through 2-FC must be filed identifying all eligible investments (to a maximum of five years) for which cost recovery is required. These appendices provide information on all costs (capital and OM&A), and the shares of total costs to be recovered from all Ontario ratepayers (net of direct benefits) and the distributor’s ratepayers. The appendices also provide a revenue requirement calculation for the asset costs to be recovered annually through Regulation 330/09 Provincial Rate Protection.

2.5.2.6 Addition of ICM Assets to Rate Base

Any distributor that has an approved ICM must file a schedule of the ICM capital asset amounts (i.e., property, plant and equipment and associate depreciation) it proposes be incorporated into rate base. The distributor must compare actual capital spending with the Board-approved amount and provide an explanation for variances. The Board will make a determination on any true-up treatment of any variance between forecast and actual capital spending during the IRM plan term.

The applicant must also file the account balances recorded under:

- Account 1508 Other Regulatory Asset, Sub-account, Incremental Capital Expenditures;
- Account 1508 Other Regulatory Asset, Sub-account, Depreciation Expense;
- Account 1508 Other Regulatory Asset, Sub-account, accumulated Depreciation; and
- Account 1508, Other Regulatory Asset, Sub-account, Incremental Capital Expenditures Rate Rider.

The distributor must provide a reconciliation between amounts recorded in these accounts and amounts used to propose what will be incorporated into rate base and explain any differences.

In the event the Board decides to approve the true up of any variances, the recalculated revenue requirement should be compared to the rate rider revenues collected in the same period and these variances should be refunded to or collected from customers through a rate rider.

2.5.2.7 Service Quality and Reliability Performance

The following information must be provided:

- Reported Electricity Service Quality Requirements ("ESQRs"), as set out in Chapter 7 of the *Distribution System Code*, for the last five completed 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 and SAIFI, for the last five completed years. The Board has determined that CAIDI will no longer be required as a filing. Reliability performance must be reported for the two 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 range, the applicant must provide an explanation for the under-performance, actions taken to address the issue, and any outcomes (if available).

A completed Appendix 2-G must be filed.

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. Estimates must be presented excluding commodity revenues.

The information presented must include:

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

2.6.1 Load and Revenue Forecasts

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 must 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 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 ("CDM") 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.

2.6.1.1 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;
    - Definition of HDD and CDD:
        - Climatological measurement point (i.e. identification of Environment Canada weather station(s)) and why that is (those are) appropriate for the distributor's service territory; and
        - Identification of base numbers from which HDDs and CDDs are measured (e.g. 18 degrees C)
    - In addition to the proposed test year load forecast, the load forecasts based on a) 10-year average and b) 20-year trend HDD and CDD; and
    - Rationale as to why the proposed normal weather methodology was chosen.

- Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, a complete explanation of the variable, data used and source of the data must be provided. Where a utility has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. billing data not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation as to why the constructed demand series is suitable for modelling; and
- Data used in the load forecast must be provided in working Microsoft Excel format. This would include showing the derivation of any constructed variables where practical.

2.6.1.2 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 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.

2.6.1.3 CDM Adjustment for the Load Forecast for Distributors

Consistent with the Board's CDM Guideline EB-2012-0003, it is expected that the distributor will integrate an adjustment into the 2014 load forecast that takes into account the measured CDM results from 2011 and 2012 CDM programs as reported by the OPA, when available. The OPA results should be taken into account for determining the amount of CDM reductions to be achieved in 2013 and 2014 in order to achieve the four-year (2011-2014) targets for kWh and kW reductions.

The license condition targets and the LRAMVA balances are based on the reported OPA results, which are annualized. It is recognized that the CDM programs in a year are not in effect for the full year, although persistence of previous year's programs will be. Therefore, the actual impact on the load forecast for the first year of the program should not be the full annualized amount. For this reason, the amount that will be used for the LRAMVA will be related to, but not necessarily equal to, the CDM adjustment for the load forecast.

Further, the actual results for 2011 and 2012 historical years, which will, in all likelihood, be used to develop the base forecast, includes the impacts of 2011 and 2012 CDM programs. The CDM adjustment to the load forecast should also take into account the historical CDM results factored into the base load forecast before the CDM adjustment, in order to avoid double counting of the impacts.

The distributor should document the CDM savings to be used as the basis for the 2014 LRAMVA balance and the corresponding adjustment to the 2014 load forecast. In addition, the allocation of the CDM savings for the LRAMVA and the load forecast adjustment should be provided by customer class and for both kWh and, as applicable, kW. The distributor should document its proposal adequately. Appendix 2-I is provided as one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast.

2.6.2 Accuracy of Load Forecast and Variance Analyses

The applicant must demonstrate the historical accuracy of the load forecast for at least the past 5 years by providing the following, as applicable:

- Schedule of volumes (in kWh and in kW for those rate classes that use this charge determinant), revenues, customer/connections 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, if applicable;
    - Bridge Year;
    - Bridge Year – weather normalized; and
    - Test Year.

A minimum of 5 historical years of customer and connection numbers must be provided. For each rate class, the applicant must also provide the following information:

- 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;
- Explanations for changes in the definition of, or major changes in the composition of, each class, such as the loss, gain or re-classification of major customers in one or more customer classes;
- 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;
- Details for the development of the billing kW value for applicable classes; and

- Revenues, provided on the basis of both existing and proposed rates.

The applicant must provide the following variance analyses and relevant discussion for volumes, revenues, customer/connections count and total system load:

- 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.

All data used to determine the forecasts must 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-H 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 2.7.3.2 For each affiliate transaction, identification of the service, the nature of the service provided to affiliated entities, accounts used to record the revenue and the associated costs to provide the service.

Revenues or costs (including interest) associated with deferral and variance accounts must <u>not</u> be included in Other Revenue.

2.7 Exhibit 4. Operating Costs

Exhibit 4 includes information that summarizes the Operating, Maintenance and Administrative ("OM&A") Costs, Depreciation Expense and Taxes.

With the release of the RRFE report, the Board is adopting an outcomes-based approach to regulation. On this basis, the review of OM&A costs will be moving towards an output / program-focused review in place of the previous approach which focused significant attention to discrete elements of the inputs to the OM&A costs. The Board recognizes that a transition period to achieve the full adoption of such an approach is necessary. As such, to the extent possible, applicants for a 2014 cost of service should do their year over year variance analyses based on their OM&A programs. For example, an OM&A program could be vegetation management, insulator washing, pole testing, cable locates, etc.

In this context, the Board has eliminated two appendices from the 2012 version of the Filing Requirements (2-G and 2-H) that required OM&A details on an account by account basis. The Board has inserted a new appendix, 2-JC, OM&A Programs Table and Variance Analysis, which provides OM&A details and variance analysis on a program basis. This table must reflect the entire OM&A envelope requested for recovery as part of the 2014 rate application. All applicants must provide information for the bridge and test years. In the absence of historical information on an OM&A program basis, and recognizing that this is a period of transition, the Board has retained the Recoverable OM&A Cost Driver Table appendix from 2012 (2-JB) which should be used to provide high-level cost driver information. All applicants must file all remaining OM&A appendices including appendix 2-JA that breaks down the OM&A envelope into major categories (e.g. Operations, Maintenance, etc).

This exhibit must include the following sections:

1) Overview;
2) Summary and Cost Driver Tables;
3) Program Delivery Costs with Variance Analysis;
4) Depreciation/Amortization/Depletion;
5) Taxes; and CDM Costs, if applicable.

2.7.1 Overview

The overview 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 Rate assumed: The Board will determine an appropriate inflation rate for use by utilities with respect to IRM rate applications, and distributors should be mindful of this rate and if adopting an inflation rate other than the rate determined by the Board should provide a full explanation as to why this has been done; and

- Business environment changes.

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-JA);
- OM&A Cost Drivers (Appendix 2-JB); and
- Recoverable 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, CGAAP, or ASPE, 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-DA or 2-DB.

2.7.3 Program Delivery Costs with Variance Analysis

As discussed previously, applicants must complete the revised Appendix 2-JC OM&A Programs Table making best efforts to identify the OM&A cost by program, and if not by major functions. This will include a variance analysis between the Test Year costs and the last Board-approved cost and the most recent actual.

Given this is a transitional period further details are still required to be filed for the following categories of costs, as discussed further in the sections that follow:

1) Employee Compensation
2) Shared Services and Corporate Cost Allocation
3) Purchase of Non Affiliate Services
4) One-time Costs
5) Regulatory Costs
6) Low Income Energy Assistance Programs
7) Charitable and Political Donations

2.7.3.1 Employee Compensation Breakdown

The applicant must complete Appendix 2-K in relation to employee complement, compensation, and benefits. Information on labour and compensation must include the total amount, whether expensed or capitalized.

The Board's RRFE Report established the process of implementing an outcomes-based regulatory model, which has as one of its objectives the achievement of increased regulatory efficiency by focussing on results instead of activities. The Board is of the view that as employee compensation costs are already reflected in the applied-for capital and expense programs, the detailed segregation of compensation costs is not necessary in the Board's consideration of the expected outcomes from the proposed program costs.

The Board has accordingly streamlined the information required in Appendix 2-K from that of previous years as the Board has determined this level of detail is no longer necessary. The Board will expect subsequent stages of the discovery process to conform to these reduced requirements unless compelling reasons can be provided as to why additional information is necessary.

In place of the details removed from Appendix 2-K, it is the Board's expectation that distributors will provide a description of their compensation strategy, and clearly explain the reasons for all material changes to head count and compensation and the outcomes expected from these changes. A complete explanation includes:

- Year over year variances, inflation rates used for forecasts, plan for any new employees and relevant details on collective agreements (such as, the date the agreement was signed, the effective date, length of term and any information available to the applicant on other collective agreements entered into in the same time period);
- 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).

Applicants who are virtual utilities (i.e. utilities which have outsourced, the majority of functions, including employees to affiliates) must also complete this appendix in relation to the employees who are doing the work of the regulated utility. In addition to the information required per Appendix 2-K, the status of pension funding and all assumptions used in the analysis must be provided.

Where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related. This higher level of aggregation must 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. The most recent actuary report(s) must be included in the pre-filed evidence. What is disclosed in the tax section of the pre-filed evidence must agree with this analysis.

2.7.3.2 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.

The applicant must identify all shared services among the affiliated entities, including the extent to which the applicant is a "virtual" utility.

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. Applicants must provide a reconciliation of the revenue arising from Appendix 2-N with the amounts included in Other Revenue in section 2.6.3.

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

- Test Year vs. Last Board-approved; 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.

2.7.3.3 Purchase of Non-Affiliate Services

Utility expenses incurred through the purchase of services from non-affiliated firms must be documented and justified. An applicant must 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 must 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.).

2.7.3.4 One-time Costs

The applicant must 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. If a distributor is not proposing that one-time costs be recovered over the test year and the subsequent IRM term, an explanation must be provided.

2.7.3.5 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. Appendix 2-M must be completed. 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., over what period the costs are proposed to be recovered). For distributors, the recovery period would normally be the duration of the expected cost of service plus IRM term under the 4^{th} generation option. If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate.

2.7.3.6 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 must 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 must 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.

A distributor must also state whether or not any amounts have been included in its test year revenue requirement for legacy programs, such as Winter Warmth. If this is the case, the programs and amounts must be identified and a brief description of each of the programs must be provided.

2.7.3.7 Charitable and Political Donations

The applicant must file the amounts paid in charitable donations (per year) from the last Board-approved rebasing application up to 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 (e.g. applicable programs under 2.7.3.6 above). If the applicant wishes to recover such contributions, it must provide detailed information for such 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 must also confirm that no political contributions have been included for recovery.

2.7.4 Depreciation, Amortization and Depletion

The information outlined below is required for Depreciation, Amortization and 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 must 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.
- 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 explanation.
- The applicant must provide a copy of its depreciation/amortization policy, if available. If not, the applicant must 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 is expected to make regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013:
    - 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 and tie this list to the Uniform System of Accounts as appropriate. 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. Appendix 2-BB must be filed.
    - Applicants must perform a recalculation to determine the average remaining life of the opening balance of assets on the date of making depreciation changes.
    - For those applicants filing an application under MIFRS, the applicant must file the applicable depreciation appendices as provided in the Chapter 2 MIFRS Appendices.
    - For those applicants filing an application under CGAAP, ASPE, or USGAAP, the applicant must file the applicable depreciation appendices as provided in the Chapter 2 CGAAP, ASPE, or USGAAP Appendices.

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 USGAAP must complete Appendix 2-CV.

2.7.5 Taxes or Payments In Lieu of Taxes (PILs) and Property Taxes

The applicant must provide the information outlined below:

- Detailed calculations of Income Tax or PILs, as applicable (including a completed pdf and live MS Excel version of the Income Tax /PILs model available on the Board's web site) , including derivation of adjustments (e.g., Tax credits, CCA adjustments) for the Historical, Bridge and Test Years. Regulatory assets (and regulatory liabilities) must 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, must be separated);
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (section 2.4.3);
- A calculation of tax credits (e.g., Apprenticeship Training Tax Credits, education tax credits). A Scientific Research and Experimental Development (“SRED”) return, if filed, may have confidential personal information of the people who are apprenticing like SIN, address, hourly rate, etc. which must be excluded from the filing; and
- Supporting schedules, calculations and explanations for “other additions” and “other deductions” in the applicant’s PILs model.

Taxes other than Payments In Lieu of Income Taxes (e.g. property taxes) should be clearly identified where included.

2.7.5.1 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 2014 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 must also be excluded from the regulatory tax calculation including the updated calculation filed as part of the draft Rate Order.

2.7.5.2 Integrity Checks

The applicant must ensure the following integrity checks have been completed in its application and provide a statement to this effect, or an explanation if this is not the case:

- 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.

2.7.6 Conservation and Demand Management Costs

CDM activity is funded either through OPA Contracted Province Wide CDM Programs, or through a Board-approved CDM program. Both of these approaches fund the programs through the global adjustment mechanism, and therefore must not be included in distribution rates.

2.7.6.1 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 period.

2.7.6.2 LRAM for pre-2011 CDM activities

Per the Board's CDM Guidelines and reinforced through the Board's decisions in the 2012 and 2013 IRM process, distributors that have rebased commencing in 2010 are not eligible for LRAM claims for lost revenue associated with the persistence of legacy programs in 2010 and beyond unless the Board explicitly stated its expectation in the

distributor's last rebasing decision (or if it was explicitly stated in a settlement agreement) that the distributor may file a claim in the future. Furthermore, the Board expects that any LRAM claims for the period prior to 2010 have been completed. Therefore, no LRAM claims are expected in 2014 cost of service applications.
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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* of December 20, 2006.

As per the 2009 Report, the Board issues the cost of capital parameter updates for cost of service applications. Distributors should use the most recent parameters as a placeholder, subject to an update if new parameters are available prior to the issuance of the Board's decision for a specific distributor's application.

If the applicant wishes to adopt the Board's guidelines for the cost of capital, the application must 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 costs (i.e. cost of power and associated 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 must be provided so that parties can map the summary cost driver information to the evidence supporting it.

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

The Revenue Requirement Work Form ("RRWF") must be filed in this exhibit in pdf along with a live MS Excel version. The revenue requirement components in the application and the resulting revenue deficiency/sufficiency in this exhibit must correspond with the calculations in the RRWF. Applicants must ensure that numbers entered in the RRWF are reconciled with the appropriate numbers in other exhibits.

2.10 Exhibit 7. Cost Allocation

The following areas are discussed in this exhibit:

1) Cost Allocation Study Requirements;
2) Class Revenue Requirements; and
3) 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) (the "Cost Allocation Review").

A completed cost allocation study using the Board-approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The most current update of the model (version 3.1) will be available on the Board's web site.

For any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used, 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 Cost Allocation Review concerning weighting factors for allocation of certain costs. A description of the weighting factors is required. Distributors are expected to develop their own weighting factors. As explained in the report, if the distributor has chosen to use the default weighting factors, an explanation must be provided.

If using the Board-issued model, the distributor must 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-15 and c-17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information. A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live MS Excel model 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, as opposed to the version that the distributor would have used in the previous re-basing application;
- 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 devices (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 the following information, as applicable:
    - Evidence that the host distributor has consulted with its embedded distributor(s) prior to preparing its cost allocation model and filing its rate application, and a statement as to whether or not the embedded distributor supports the host distributor's approach to the allocation of costs.

  - If the host has a separate rate class for its embedded distributor(s) the host distributor must include the class as such in its cost allocation study and in Appendix 2-P.
  - If the host proposes to establish a new class, the host distributor must include the class as such in its cost allocation study and in Appendix 2-P and provide rationale and supporting evidence for the establishment of an Embedded Distributor class, where applicable. The host must provide the cost of serving the embedded distributors, load served, information regarding ownership of relevant assets involved in the connection(s), and the distribution charges levied.
  - If the host distributor proposes to bill the embedded distributor(s) as if it/they were General Service Class customers, the costs and revenue must be included with that class in the cost allocation study and Appendix 2-P. In this case, 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), regardless of the fact that they are not treated as a distinct rate class elsewhere. The host must provide the cost of serving the embedded distributors, load served, information regarding ownership of relevant assets involved in the connection(s), and the distribution charges levied. Additionally, the host distributor must provide evidence supporting the continued appropriateness of the rate class that is being used to levy distribution charges on the embedded distributor;

- microFIT class: The Board does not expect a distributor to include microFIT as a separate class in the cost allocation model in 2014.The model will produce a calculation of unit costs which the Board will use to update the uniform microFIT rate at a future date. Unlike other classes, the cost information is not used to establish a separate class revenue requirement for the microFIT class;
- New Customer Class(es): If the distributor is establishing a new customer class, the rationale for doing so is required, and information provided in the distributor's previous cost of service application concerning class revenue requirements must be restated in Appendix 2-P on the basis of the proposed customer classes, to provide continuity with the proposed new customer class(es); and
- Eliminated Customer Class(es): If the distributor is proposing to eliminate or combine existing customer classes the distributor must identify such proposals and the supporting rationale. To the extent possible, the distributor must restate information from its previous cost of service application concerning class revenue requirements in Appendix 2-P, on the basis of the proposed customer classes to provide continuity of information.

2.10.2 Class Revenue Requirements

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 must 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. The distributor must 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) must 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 deferral and variance accounts such as Smart Meter costs and that revenues exclude rate riders, rate adders and the Smart Metering Entity charge. The distributor must 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 exhibit:

1) Fixed/Variable Proportion;
2) Retail Transmission Service Rates (RTSRs);
3) Retail Service Charges;
4) Wholesale Market Service Rate;
5) Smart Metering Charge
6) Specific Service Charges;
7) Low Voltage Service Rates (where applicable);
8) Loss Adjustment Factors;
9) Tariff of Rates and Charges;
10) Revenue Reconciliation;
11) Bill Impact Information; and
12) Rate Mitigation (where applicable).

Please note that monthly fixed charges must be shown to two decimal places while variable charges must be shown to four places. Distributors wishing to depart from this approach must 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 must 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 must 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 completed version of the RTSR model must be filed in pdf and live MS Excel.

The distributor must ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.5.1.3, 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. Distributors should note that the current retail service rates and charges were established on a generic basis. The Board expects distributors 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 must 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. The RCVAs are discussed in section 2.12.6.

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.

This rate will be set by the Board on a generic basis. Distributors wishing to apply for a rate other than the generic rate set by the Board must provide justification as to why their specific circumstances would warrant such a change.

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. Furthermore, the Board approved the rate for rural and remote rate protection (“RRRP”) to be $0.0012 per kilowatt hour. Distributors should reflect a total charge of $0.0056 in their applications.

2.11.5 Smart Metering Charge

On March 28, 2013, the Board issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering charge of $0.79 per month for Residential and General Service < 50kW customers effective May 1, 2013. Distributors should reflect this charge in their applications.

2.11.6 Specific Service Charges

A distributor must describe the purpose of each new or revised specific service charge for which it is seeking approval. Distributors must specify which charges are new and for which existing charges they are proposing changes.

Distributors requesting either a new specific service charge or a change to the level of an existing charge should describe the purpose of such charges, or the reason for the proposed change to an existing charge and provide calculations supporting the determination of each such 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).

Distributors must also identify any rates and charges that are included in the Conditions of Service but do not appear on the Board-approved tariff sheet, and an explanation for the nature of the costs being recovered must be provided. A schedule outlining the revenues recovered from these rates and charges from 2009 to 2012 and the revenue forecasted for the 2013 bridge and 2014 test years must also be provided as well as an explanation whether these rates and charges must be included on the applicant’s tariff sheet.

Distributors must ensure that the revenue from the total of the proposed specific service charges corresponds with the evidence under Operating Revenues (see section 2.6.3).

2.11.7 Low Voltage Service Rates (where applicable)

If the distributor is embedded (see section 2.4.5) the distributor must provide the following information:

- Forecast of LV cost, which is the sum of the host distributor's charges to the applicant;
- Actual LV costs for the last three historical years, along with bridge and test year forecasts. The distributor must also provide the year-over-year variances, and explanations for substantive changes in the costs over time, up to and including the test Year forecast;
- Support for the forecast of LV costs: forecast volumes and actual or forecast host distributor's LV rates. For example, an applicant distributor whose host distributor is Hydro One would include the distributor's costs for Sub-Transmission lines, plus a Sub-Transmission service charge, plus any other charges such as facility charges for connection to a shared distribution station that apply to the embedded distributor'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.

2.11.8 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 distributor 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%;

- If proposed distribution loss factor is greater than 5%, details of actions taken to reduce losses in previous five years and actions planned to reduce losses going forward; and
- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-R, Row H.

2.11.9 Tariff of Rates and Charges

The distributor must provide the current and proposed tariff of rates and charges. The distributor must also provide a marked-up (track changes) version of the currently approved tariff of rates and charges showing each proposed change. Distributors must ensure that each proposed change is explained and supported in the appropriate section of the application. Distributors must file the new Tariff of Rates and Charges appendix (Appendix 2-Z).

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

2.11.10 Revenue Reconciliation

For the proposed tariff of rates and charges, the following information must 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 a completed Appendix 2-V.

2.11.11 Bill Impact Information

Appendix 2-W must be filed for all classes. This appendix identifies existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass-through costs – "Sub-Total A", % change in distribution – "Sub-Total B", % change in delivery – "Sub-Total C", and % change in total bill).

The distributor must 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 must 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 must 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. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided in Appendix 2-W.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted, the distributor must show a typical comparison, and provide an explanation.

2.11.12 Rate Mitigation (where applicable)

2.11.12.1 RRFE Report Mitigation Statements

In the RRFE report the Board concluded that it will maintain its current policy on rate mitigation.

The Board stated that the implementation of the renewed regulatory framework makes the need for mitigation of large rate increases less likely as controls to address cost increases are integrated into the planning and rate-setting processes, and each distributor will be able to choose the rate-setting approach that best suits its particular investment profile.

The Board further stated that it would expect distributors to consider total bill increases when they engage in planning, an exercise that will be facilitated under the integrated approach to network planning described in Chapter 5 and to demonstrate to the extent possible the responsiveness of their planned capital and OM&A expenditures to the need for reasonably stable and affordable rates for customers.

2.11.12.2 Mitigation Plan Approaches

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

- 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;
- A detailed description of any mitigation measures undertaken, e.g. reductions to the revenue requirement, inter- or intra-class shifts, or longer disposition periods for deferral and variance account balances;

- A justification for all mitigation measures proposed;
- Revised impact calculations; and
- Any other information the distributor believes is relevant.

The distributor must ensure that Appendix 2-W reflects any mitigation plan proposed in the application.

The bill comparisons must assume a constant commodity price and other rates, despite potential changes such as changes in the commodity price and other rates that 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 determination must be stipulated in the mitigation plan and supported with sufficient rationale.

2.11.12.3 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, must 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 must include a discussion of proposed measures to mitigate any such increases in its mitigation plan discussed in section 2.11.12 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 must 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;
- A 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. 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 account balances in the continuity schedule differ from the account balances in the trial balance reported through the *Electricity Reporting and Record-keeping Requirements* and the Audited Financial Statements;
- Identification of which Group 2 accounts the distributor will continue and discontinue on a going-forward basis, with an explanation for each;
- If a distributor is proposing to allocate a deferral or variance account for which the Board has not established an approved allocator, the distributor must propose an allocator based on the cost driver(s), along with the charge type (fixed or variable) for recovery purposes, and include this in the continuity schedule.
- Statement as to any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account. This must correspond with information provided in Exhibit 1 (see section 2.4.5);
- A statement as to whether or not 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; under a section titled "Adjustments to Deferral and Variance Accounts."
- A breakdown of energy sales and cost of power expense balances, as reported in the Audited Financial Statements by distributors, mapped to USoA account number. The distributor must reconcile these numbers to the Audited Financial Statements. If there is a difference between the energy sales and cost of power expense reported numbers, the distributor must explain why it is making a profit or loss on the commodity;
- A statement confirming that the distributor pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, the distributor must provide an explanation.

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

If the distributor has not already filed for disposition in a prior rate year, the Board expects distributors to file for disposition of account 1592 in their cost of service applications. Distributors must complete and file Appendix 2-TA in support of their request to dispose of account 1592.

2.12.2 Harmonized Sales Tax Deferral Account

During the 2010 IRM application process, the Board directed electricity distributors to record in deferral account 1592 (PILs and Tax Variances for 2006 and subsequent years, Sub-account HST/OVAT ITCs), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

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

No more amounts should be recorded in Account 1592 (PILs and Tax Variances for 2006 and subsequent years, 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 must be reflected in the applied-for revenue requirement. For the 2014 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, 2013 since the test year, which starts January 1, 2014 would include the HST impacts in rates going forward. If the test year's rate year begins May 1, 2014, entries to record variances in the sub-account of Account 1592 would cover the period from July 1, 2010 to April 30, 2014.

The distributor must provide an analysis that supports the distributor's conformity with December 2010 APH FAQs, in particular the example shown in FAQ # 4.
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2.12.3 One-time Incremental IFRS Costs

As per the October 2009 APH FAQ #1 and FAQ #2, an applicant must file a request for review and disposition of the balance in Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance, in its next cost of service rate application immediately after the IFRS transition period.

For an applicant that files a 2014 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 must file a completed Appendix 2-U and 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;
- Provide a statement as to whether any one-time administrative incremental IFRS transition costs are embedded in the proposed 2014 revenue requirement. If this is the case, the applicant must state the section of the proposed 2014 revenue requirement that includes these costs;
- Include any amounts in rates as credits on a separate line in Appendix 2-U if an applicant has one-time administrative incremental IFRS transition costs already included for recovery in its rates;
- Provide explanations for each category of costs recorded in the Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance Account. The applicant must explain how the costs recorded meet the criteria of one-time IFRS administrative incremental costs;
- Provide explanations for material variances that may exist in the Account 1508 Other Regulatory Assets, Sub-account IFRS Transition Costs Variance account; and
- Per the October 2009 APH FAQ #3 regarding costs that are permitted to be recorded in the Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs Account and Account 1508 Other Regulatory Assets, Sub-account 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 Account 1508 Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs Account or Account 1508 Other Regulatory Assets, Sub-account 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

Account 1575 will apply to an applicant that files a 2014 cost of service application on the basis of MIFRS. For an applicant filing based on MIFRS, Account 1575 must capture all PP&E accounting changes made on transition to IFRS, not just those related to capitalization and depreciation.

Deferral Account 1575 and variance Account 1576 cannot be used interchangeably and the applicant must follow the required accounting treatment applicable under each account. The accounting changes applicable to Account 1576 are not applicable to Account 1575 in relation to “changeover date” accounting on the applicant’s adoption of IFRS.

Per its letter dated June 25, 2013, effective for the 2014 cost of service rate applications and subsequent rate years, the Board will require the use of a separate rider for the disposition of the balance in Account 1575.

Applicants must provide the following:

- A breakdown of the balance related to the IFRS-CGAAP Transitional PP&E Amount that is effective on the transition date to modified IFRS. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-EA, 2-EB, or 2-EC;
- A listing and quantification of the drivers of the change in closing net PP&E (CGAAP versus modified IFRS). The Fixed Asset Continuity Schedule (Appendix 2-BA1 or 2-BA2) in the rate application must not be adjusted for balances related to the IFRS-CGAAP Transitional PP&E Amount. The applicant must show that the application of the accounting policies change is applied on a prospective basis in the year in which the accounting changes occurred (e.g., 2013);
- A breakdown for quantification of any accounting changes arising from the transition to IFRS in relation to PP&E (e.g. customer contributions, asset retirement obligations, interest capitalization, etc.), including an explanation for each of the accounting changes made by the applicant;
- A separate volumetric rate rider for Account 1575 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised of the amortized amount of the account balance over the number of years proposed for the disposition period (e.g. five years);
- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1575, including all calculations showing its derivation. The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1575 rate rider. The amount for the return component must not be recorded in the Account 1575;
- A statement confirming that no carrying charges are applied to the balance in the account;
- An explanation for the basis of the proposed disposition period to clear the Account 1575 rate rider. The Board’s determination of the disposition period will be on a case-by-case basis and that it will be guided primarily by such considerations as bill impacts and the financial impact on applicants; and
- The balance of the account in the DVA Continuity Schedule for the cost of service application.

2.12.5 Account 1576, Accounting Changes Under CGAAP

Applicants will use Account 1576 to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under Canadian GAAP or ASPE in 2012 or as mandated by the Board in 2013.

Account 1576 will apply to an applicant that files a 2014 cost of service application on the basis of CGAAP or ASPE. For an applicant that files a 2014 test year application under modified IFRS and made the changes to accounting capitalization or depreciation policies in 2012 or 2013 under CGAAP, the applicant must file with the Board a request to clear Account 1576 for these changes as part of the cost of service application.

Per its letter dated June 25, 2013, effective for the 2014 cost of service rate applications and subsequent rate years, the Board will require a rate of return component to be applied to the balance in Account 1576 and require the use of a separate rider for the disposition of the balance in Account 1576.

- For accounting changes made in 2012, Account 1576 would capture the accounting changes made in 2012 under CGAAP. The applicant must incorporate the impact of these changes in both the Historic year (2012) and Bridge year (2013) for applicants making the changes to the accounting capitalization or depreciation policies effective January 1, 2012; or
- For accounting changes made in 2013, Account 1576 would capture the accounting changes made in 2013 under CGAAP. The applicant must incorporate the impact of these changes in the Bridge year (2013) for applicants making the changes to the accounting capitalization or depreciation policies effective January 1, 2013.

Applicants must provide the following:

- The Fixed Asset Continuity Schedule (Appendix 2-BA1 or 2-BA2) in the rate application, which must not be adjusted for balances related to Account 1576. The applicant must show that the application of the accounting policies change is applied on a prospective basis in the year in which the accounting charges occurred (e.g., 2013);
- A breakdown of the balance related to Account 1576. The applicant must provide the supporting analysis of the amounts in this account by completing Appendices 2-ED or 2-EE. The drivers of the change in closing net PP&E (former policies under CGAAP versus revised policies under CGAAP or ASPE) must be identified and quantified;
- A separate volumetric rate rider for Account 1576 for the clearance of the account balance over the proposed disposition period, including all calculations showing its derivation. The applicant must show that the rate rider is comprised

of the amortized amount of account balance over the number of years proposed for the disposition period (e.g. five years);

- A rate of return component (i.e., weighted average cost of capital) to be applied to the balance of Account 1576, including all calculations showing its derivation. The rate of return amount must be amortized over the number of years proposed for the disposition period (e.g. five years) and added together with the account balance amortized amount for inclusion in the Account 1576 rate rider. The amount for the return component must not be recorded in the Account 1576;
- A statement confirming that no carrying charges are applied to the balance in the PP&E account;
- An explanation for the basis of the proposed disposition period to clear the account balance through the Account 1576 rate rider. The Board's determination of the disposition period will be on a case-by-case basis and will be guided primarily by such considerations as bill impacts and the financial impact on distributors; and
- The balance of the account in the DVA Continuity Schedule for the cost of service application.

2.12.6 Retail Service Charges

If the distributor has material debit or credit balances in Account 1518 RCVA Retail or Account 1548 RCVA STR, the distributor must:

- Confirm that all costs incorporated into the variances reported in Account 1518 and Account 1548 are incremental costs of providing retail services;
- Identify the drivers for the balances in Account 1518 and/or Account 1548;
- Provide a schedule identifying all revenues and expenses listed by USoA account number, that are incorporated into the variances recorded in Account 1518 and/or Account 1548 for 2012, the actual/forecast for 2013 and a forecast for 2014; and
- State whether or not the distributor has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. The distributor must provide an explanation and quantify the variance if the distributor has not followed Article 490.

If the distributor has zero balances in Account 1518 RCVA Retail or Account 1548 RCVA STR, the distributor must state whether or not it has followed Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for these accounts. The distributor must provide an explanation and quantify the variance if Article 490 has not been followed.

2.12.7 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 must be provided;
- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements and provide explanations for any variances;
- Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's RRR filings for each account;
- Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. conformance with the APH or prior Board decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference between what is proposed for disposition in total before forecasted interest and what is recorded in the RRR filings ;
- 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 must be expensed in the normal course and addressed through organizational productivity improvements; and
- 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.

2.12.8 LRAM Variance Account (LRAMVA) for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 period, 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 CDM adjustment to the load forecast, to the actual CDM results. The variance calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes.

2.12.8.1 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 lost revenue amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the OPA in support of its lost revenue calculation and a copy of this report;
- Separate tables for each rate class showing the lost revenue amounts requested by the year they are associated with and the year the lost revenues took place;
- Lost revenue 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 lost revenue amount; and
- 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 lost revenue calculations, including:

- o Confirmation of the use of correct input assumptions and lost revenue calculations;
- o Verified participation amounts;
- o 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; and
- o Verification of any carrying charges requested.

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

2.12.9 Smart Meters

If the applicant is applying for smart meter-related recoveries, the applicant must 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.

Distributors must apply for the disposition of smart meter costs, subsequent inclusion in rate base, and for recovery of stranded costs, 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 distributor must clearly document this, and in the latter case, must identify the specific adjustments to rate base and OM&A.

Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications

Chapter 3

4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index

July 17, 2013

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Appendix C: Rate Adder versus Rate Rider

Chapter 3 Filing requirements for 4th Generation Incentive Rate-setting and annual Incentive Rate-setting Index

3.1 Introduction

On October 18, 2012, the Board issued its Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report"). The RRFE Report provides a comprehensive performance –based approach to regulation and sets out three rate-setting methods: 4th Generation Incentive Rate-setting ("4th Generation"), Custom Incentive Rate-setting ("Custom IR") and the Annual Incentive Rate-setting Index ("Annual IR Index").

The RRFE Report also established a transition plan to facilitate the early adoption of the three new rate-setting methods. Those distributors who are within the term of their current 3rd Generation IR will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR. The annual adjustment mechanism and other potential rate adjustments will be the 4th Generation IR mechanism. Distributors may opt for the Annual IR Index at any time.

The Filing Requirements herein set out the Board's expectations for filings by electricity distributors that are applying for annual rate adjustments under 4th Generation IR or the Annual IR Index. These Filing Requirements replace version 3.0 of Chapter 3 of the Filing Requirements for Transmission and Distribution Applications ("Filing Requirements"), dated June 28, 2012. The Board will not set specific filing requirements for the Custom Incentive Rate-setting method other than Chapter 5, Consolidated Capital Plan Filing Requirements, issued March 28, 2013.

The key elements for the three rate-setting methods were set out in the RRFE Report in the following table:

Table 1: Rate-Setting Overview – Elements of the Three Methods

<table>
<tr><th colspan="2"></th><th>4th Generation IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
<tr><td colspan="2">Term</td><td>5 years (rebasing plus 4 years).</td><td>Minimum term of 5 years.</td><td>No fixed term.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td colspan="3">The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo</td><td>Status quo, plus as needed to track capital spending against plan</td><td>Disposition limited to Group 1
Separate application for Group 2</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td></tr>
</table>

3.1.1 Key References

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

- *Report of the Board on the Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach – October 18, 2012;*
- *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;*
- *Chapter 5 of the Filing Requirements for Electricity Transmission and Distribution Applications: Consolidated Distribution System Plan Filing Requirements – March 28, 2013;*
- *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.*

3.1.2 Grouping for Filings

Distributors that are seeking rate adjustments effective January 1, 2014 under an IRM will be required to file their application by August 16, 2013. For those distributors that are seeking IRM rate adjustments effective May 1, 2014, the Board will assign electricity distributors in one of five 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. Distributors filing under the Annual IR Index method will be placed in the last grouping. 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 30, 2013
- Friday September 13, 2013
- Friday September 27, 2013
- Friday October 11, 2013
- Friday October 25, 2013

Board staff will survey potential IRM applicants in June 2013 requesting that applicants that are seeking rate adjustments effective May 1, 2014 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 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 for those who have not yet filed a Chapter 5 Distribution System Plan in a cost of service rate application.

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

3.1.3 Components of the Application Filing

Whether filing under 4th Generation IR or the Annual IR Index, each application must include:

- A Manager's Summary thoroughly documenting and explaining all rate adjustments applied for;
- The contact information for the application - 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;

- 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 who will be affected by the application, and which publication(s) the applicant proposes that notice must appear, whether it is a paid publication or not and the readership and circulation numbers, and the rationale for why the stated publication(s) are appropriate; and
- A text-searchable Adobe PDF format for all documents.

3.1.4 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.

3.1.5 Applications and Electronic Models

The models issued by the Board are provided to assist the applicant in filing a rate application and to provide consistent formatting for all distributors for greater efficiency of the review process. An application to the Board is the applicant's responsibility and the Board expects that the application will be complete and accurate. Likewise, the applicant bears the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses in supporting its application. The applicant is responsible for advising the Board of any concerns it may have regarding calculations flowing from the models as well as any changes that the applicant may have made to the models to address its own circumstances. Given the variety of different circumstances to be considered, the use of a Board model does not necessarily mean that the Board will approve the results.

3.1.6 Other Rate Adjustments

[1] The Rate Generator is a Microsoft Excel workbook that calculates a distributor's proposed tariff of rates and charges in a 4th Generation IR or Annual IR Index Application.
[2] Includes the Shared Tax Savings Workform, Revenue Cost Ratio Adjustment Workform, Incremental Capital Module ("ICM") Workform, Deferral and Variance Account Workform and RTSR Adjustment Workform as applicable.
[3] The Revenue Requirement Work Form was filed as part of the draft rate order in the last cost of service application.

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.

3.2 Common Elements of the 4th Generation IR Plan and the Annual IR Index

3.2.1 Annual Adjustment Mechanism

As with the 3rd Generation IR, the annual adjustment mechanism is defined as the annual percentage change in the Inflation factor less an X-Factor (i.e. productivity factor and a stretch factor). The Board determined that the X-factor for the Annual IR Index will be set using the highest stretch factor set for 4th Generation IR in 2014.
As part of its supplemental report on the RRFE the Board will establish the final inflation factor, productivity factor and stretch factor to apply to distributors for 2014.

The Rate Generator will initially include rate-setting parameters from the preceding calendar year as a placeholder: inflation factor of 1.6%, productivity factor of 0.72% and a stretch factor of 0.4% (representing the middle cohort) for a total price index adjustment of 0.48%.

Board staff will update each distributor's Rate Generator with the final parameters to be established by the Board in the supplemental report on the RRFE. The Board expects to issue its Letter of Direction to proceed with the Notice of Application subsequent to this update. Distributors will have an opportunity to comment on the accuracy of Board staff's update as part of the draft Rate Order process.

3.2.1.1 Application of the Annual Adjustment Mechanism

The annual adjustment mechanism will apply to distribution rates (fixed and variable charges) uniformly across customer rate classes.

The annual adjustment mechanism 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; and[4]
- Smart Metering Entity Charge.

3.2.2 Z-factor Claims

Z-factors are intended to provide for unforeseen events outside of a distributor's management control, regardless of a distributors' rate-setting mechanism at the time of the event. 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 Account 1572, Extraordinary Event Costs, related to a Z-factor claim.

3.2.2.1 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 2: 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.

4 *and any other allowances the Board may determine.*

3.2.2.2 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.

3.2.2.3 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.

3.2.2.4 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[5]. The request must specify whether the

[5] *See Appendix C*

rate rider(s) will apply on a fixed or variable basis or a combination thereof, and the length of the disposition period and a rationale for this proposal. A detailed calculation of the incremental revenue requirement and resulting rate rider(s) must be provided.

3.2.2.5 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.

3.2.3 Off-ramps

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

The RRFE Report confirmed that the Board's policy in relation to the off-ramp, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, continues to be appropriate. Each rate-setting method will include a trigger mechanism with an annual regulatory return on equity ("ROE") dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated.

The Board will 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, termination or the continuation of the respective 4th Generation IR or Annual IR Index plan for that distributor.

3.2.4 Tax Changes

Under a 4th Generation IR or Annual IR Index plan, a 50/50 sharing[6] 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

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

or refunded to customers each year of the plan term, over a 12-month period, through an explicit volumetric rate rider derived using the annualized consumption by customer class underlying the Board-approved base rates.

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 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.

3.2.5 Review and Disposition of Group 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 under the 4th Generation IR or the Annual IR Index, 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, 2012 to determine if the threshold has been exceeded. A continuity schedule, found on sheet 5 of the Rate Generator, must be completed as part of the application, regardless of whether the pre-set 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;
- 1589 RSVA Global Adjustment Account; and
- 1590 Recovery of Regulatory Asset Balances Account (if applicable); 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 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.

In most recent decisions for electricity distributors, 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 account balances.

Distributors must provide an explanation if the account balances in the continuity schedule differ from the account balances in the trial balance reported through the Electricity Reporting and Record-keeping Requirements and the Audited Financial Statements.

Distributors must make a statement as to whether or not any adjustments were made to deferral and variance account balances that were previously approved by the Board on a final basis in either a cost of service or IRM proceeding (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, a distributor must provide explanations in its application for the nature and amounts of the adjustments and include supporting documentation; under a section titled “Adjustments to Deferral and Variance Accounts.”

3.2.6 LRAM Variance Account (LRAMVA) for 2011 – 2014

For CDM programs delivered within the 2011 to 2014 period, 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.

3.2.6.1 Disposition of the LRAMVA

At a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their cost of service 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, and specifically the actual results used in the determination of the LRAMVA balance to be disposed, 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 lost revenue amount;
- A statement indicating that the distributor has relied on the most recent and appropriate final CDM evaluation report from the OPA in support of its lost revenue calculation and a copy of this report;
- Separate tables for each rate class showing the lost revenue amounts requested by the year they are associated with and the year the lost revenues took place;
- Lost revenue 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 lost revenue 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 lost revenue calculations, including:
    - Confirmation of the use of correct input assumptions and lost revenue 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; and
    - Verification of any carrying charges requested.

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

An application to dispose of the balance in an LRAMVA may only be filed as part of an Annual IR Index application if the Board's decision for the distributor's last cost of service (or settlement agreement approved by the Board) has a clear description of class-specific CDM adjustments made to the load forecast to be used in the calculation of the LRAMVA balance. Any LRAMVA applications determined by the Board to be more complicated than appropriate for an Annual IR Index application will be bifurcated and heard separately from the Annual IR Index application.

3.2.7 Revenue-to-Cost Ratio Adjustments

The Board's Decisions for some distributors' 2011, 2012 and 2013 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.

3.2.8 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-2012-0031), issued on December 20, 2012 and effective January 1, 2013. Once any January 1, 2014 UTR adjustments are determined, Board staff will adjust each distributor's 2014 RTSR model and Rate Generator to incorporate these changes. Similarly, for embedded distributors whose host is Hydro One Networks Inc. ("Hydro One") Board staff will adjust the 2014 RTSR model to reflect any changes in Hydro One's Sub-Transmission class RTSRs. For hosts other than Hydro One, Board staff will adjust the 2014 RTSR models to incorporate the host embedded distributor class RTSRs. Distributors will have an opportunity to comment on the accuracy of Board staff's updates as part of the draft Rate Order process.

3.2.9 Conservation and Demand Management Costs for Distributors

CDM activity is funded either through OPA Contracted Province Wide CDM Programs, or through a Board-approved CDM program. Both of these approaches fund the programs through the global adjustment mechanism, and therefore must not be included in distribution rates.

3.2.10 Regulatory Accounting Policy Changes to the Depreciation Expense and Capitalization Policies

Per the Board's letter of July 17, 2012, electricity distributors electing to remain on CGAAP or choosing to adopt Accounting Standards for Private Enterprise ("ASPE") must implement regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These changes are mandatory as at January 1, 2013 for all distributors that have not yet made these changes, and therefore all applications for 2014 IR rates should reflect that these changes were made in 2012 or 2013. These accounting changes under CGAAP and ASPE should be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinectrics Report, and the revised 2012 APH.

Where a distributor seeks an ICM and/or Z-factor treatment in its IRM application, the financial information supporting the ICM and/or Z-factor must incorporate the changes for the depreciation expense and capitalization policies as per Board's letter of July 17, 2012.

3.3 Elements Specific to the 4th Generation IR Plan

3.3.1 Incremental Capital Module

The incremental capital module ("ICM") is only available to electricity distributor opting for 4th Generation IR. The ICM is intended to address the treatment of capital investment needs that arise during the rate-setting plan which are incremental to the materiality threshold defined below. Applicants should note that custom approaches to rate-setting should be addressed through selecting the Custom IR option, not by customizing an ICM application.

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.

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.

3.3.1.1 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.

3.3.1.2 Eligible Incremental Capital Amount

In the Supplemental Report, the Board determined that eligible incremental capital amount sought for recovery should be 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 2014 total non-discretionary capital expenditures and the materiality threshold.

3.3.1.3 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[7]. The Board has adopted this as a clarification to the policy on ICM.

3.3.1.4 Revenue Requirement Calculation

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

- Cost of Capital
  - In the December 11, 2009 Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "2009 Report") the Board confirmed the continuation of a deemed 60/40 debt-equity ratio. A distributor filing for an ICM adjustment shall use this deemed capital structure.
  - 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 rate adjustments for 4th Generation IR, 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.

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

3.3.1.5 ICM Filing Guidelines

The Board requires that a distributor requesting relief for incremental capital during the IRM plan term must include comprehensive evidence to support the 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 (but not necessarily the least initial cost) for ratepayers;

- Justification that amounts being sought are directly related to the 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 (i.e. the cost of capital, depreciation, and PILs) associated with each proposed incremental non-discretionary capital project;

- 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 would take in the event that the Board does not approve the application.

- Calculation of a rate rider to recover the incremental revenue from each applicable customer class and the rationale for the proposed approach.

3.3.1.6 ICM Reporting Requirements

At the time of the next rebasing, a distributor will need to file a calculation of the actual ICM amounts to be incorporated into 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.

3.3.1.7 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 being 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 charge 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.

3.3.1.8 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 class specific rate riders.

3.3.2 Treatment of Costs for 'eligible investments'

On March 28, 2013, the Board issued Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5: Consolidated Distribution System Plan Filing Requirements ("Chapter 5"). As noted in section 5.0.5, Chapter 5 supersedes the Filing Requirements: Distribution System Plans - Filing under Deemed Conditions of Licence.

As indicated in the cover letter to Chapter 5 dated March 28, 2013, distributors who have yet to file under Chapter 5 will continue to be able to record renewable energy generation costs and smart grid demonstration costs in the deferral accounts that were established for that purpose. However, no new deferral accounts for these types of expenditures will be established. Distributors under 4th Generation, who have yet to file a cost of service application containing a consolidated capital plan pursuant to Chapter 5, will continue to be able to request advance funding through a funding adder for renewable generation connection costs and smart grid development costs 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.

Distributors proposing to file an Annual IR Index application must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and are required to do so at five year intervals thereafter while using the Annual IR Index method.

3.4 Specific Exclusions from 4th Generation or Annual IR Index Applications

The IRM application process is 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;
- Disposition of the balance of Account 1555 – Smart Meter Capital Costs, sub-account Stranded Meter Net book Value;
- Changes to revenue-to-cost ratios, other than pursuant to a prior Board decision;
- Loss Factor Changes;
- Establishing or changing Specific Service Charges;
- Loss Carry Forward Adjustments to PILs/taxes;
- Disposition of Group 2 Accounts; 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 under the 4^{th} Generation plan may elect to include this element as part of its 2014 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.

The exclusions above also apply to the Annual IR Index plan with the exception of the following elements. As indicated in the RRFE Report, distributors filing under the Annual IR Index plan must file a separate application for the review and disposition of Group 2 Accounts. Smart meter costs (including stranded meters) should also 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 incurring such costs is examined, and the costs may be 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 review of the proposed costs to determine that it is reasonable for the distributor to incur and recover them. Rate riders are identified and listed separately on a distributor's Tariff of Rates and Charges, with an explicit sunset or termination date.

Treatment of negligible rate adders and rate riders 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 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

Filing Requirements for Electricity Transmission and Distribution Applications

Chapter 5

Consolidated Distribution System Plan Filing Requirements

March 28, 2013

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CHAPTER 5 CONSOLIDATED DISTRIBUTION SYSTEM PLAN FILING REQUIREMENTS

Glossary

Where applicable, definitions set out in the Distribution System Code (DSC) apply to terms used in these filing requirements. Certain other terms used here are explained below.

Distribution System Plan duration is the duration of a distributor's *Distribution System Plan*, which is a minimum of ten (10) years in total and comprised of an *historical period* and a *forecast period*

Forecast period is the last five (5) years of the *Distribution System Plan duration*, consisting of five (5) forecast years, beginning with the Test year

General plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

Historical period is the first five (5) years of the *Distribution System Plan duration*, consisting of five (5) historical years, ending with the Bridge year

REG investments accommodate the connection of renewable energy generation (including connection assets, expansions and/or renewable enabling improvements) the costs of which are the responsibility of the distributor as set out in the DSC. REG investments can be stand-alone or integrated into a project/activity; and are to be categorized for the purposes of section 5.4 in the same way as any other investment

Regional Infrastructure Plan is a document issued by the transmitter leading a Regional Planning Process that identifies forecast regional electricity service requirements, and describes and justifies the optimal infrastructure investments planned to meet those requirements

Regional Planning Process is a consultation involving distributors, transmitter(s), and the Ontario Power Authority convened for the purpose of exchanging information related to system planning, coordinating the modification of a regional electricity transmission system, and preparing and issuing a Regional Infrastructure Plan

System access investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system

System O&M are routine operations and maintenance activities carried out to sustain required distribution system performance to the end of the subject asset's service life

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

5.0 Introduction

These filing requirements set out the information required by the Board under the renewed regulatory framework for electricity to assess distributor applications involving planned expenditures on distribution system and other infrastructure.[1] For the purposes of these filing requirements, a *Distribution System Plan* ("DS Plan") consolidates documentation of a distributor's asset management process and capital expenditure plan, where:

- an *Asset Management Process* is the systematic approach a distributor uses to collect, tabulate and assess information on physical assets, current and future system operating conditions and the distributor's business and customer service goals and objectives to plan, prioritize and optimize expenditures on system-related modifications, renewal and operations and maintenance, and on general plant facilities, systems and apparatus; and
- a *Capital Expenditure Plan* sets out and robustly justifies according to the Board's standard requirements for evaluation a distributor's proposed expenditures on its distribution system and (non-system) general plant over a five-year planning period, including investment and asset-related maintenance expenditures.

Filing DS Plans consistent with these requirements will ensure that the Board's expectations for a distributor's planning are met; namely, that the DS Plan optimizes investments and reflects regional and smart grid considerations; serves present and future customers; places a greater focus on delivering value for money; aligns the interests of the distributor with those of customers; and supports the achievement of public policy objectives.[2]

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity[3], and necessary to ensure that the performance outcomes the Board has established for electricity distributors are being achieved:

Customer Focus: services are provided in a manner that responds to identified customer preferences;

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

1 The renewed regulatory framework for electricity is a comprehensive, performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. See *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*; (the "*RRFE Report*"); p. 2.

2 *RRFE Report*; p. 1.

4 *RRFE Report*; p. 36.

Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

DS Plan filings must enable the Board to assess whether and how a distributor has planned to deliver value to customers. One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in a manner that considers rate impacts. To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments.[4]

5.0.1 Purpose of filing a Distribution System Plan

Good distributor planning is an essential pre-requisite to the performance-based rate-setting approaches established under the renewed regulatory framework for electricity. Filing a DS Plan with an application to the Board will provide information to the Board and interested stakeholders including but not necessarily limited to a distributor's:

- asset related performance objectives and approach to evaluating its performance relative to those objectives;
- approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and
- plan for capital-related expenditures over the five-year forecast period.

5.0.2 Application and scope

These filing requirements apply to licenced, rate regulated electricity distribution utilities in Ontario when filing DS Plans as required by the Board as set out in section 5.1.3 of these requirements.

5.0.3 Framework for distribution system plans

The content of these filing requirements has been informed by the Board's expectations for distribution system planning under the renewed regulatory framework for electricity.

4 *RRFE Report*; p. 36.

5.0.3.1 Integrated planning

An integrated approach to planning, whereby investments for system renewal and expansion, renewable generation connections, smart grid development and implementation, and regionally planned infrastructure are planned and optimized together, will provide the necessary foundation for distribution rate-setting under the renewed regulatory framework; help distributors to pace and prioritize projects; and support the achievement of the four outcomes for electricity distributors.[5]

5.0.3.2 Longer term planning horizon

Under the renewed regulatory framework, a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles, which are a minimum of five-years in expected duration.[6] This longer term approach should:

- enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and distributors;
- facilitate the cost-effective and efficient implementation of distributor DS Plans and thereby the achievement of customer service and cost performance outcomes; and
- help distributors to manage consumer rate impacts.[7]

5.0.3.3 Regional considerations

Planning the distribution system infrastructure in a regional context will help promote the cost effective development of electricity infrastructure in Ontario. Regional issues and requirements are to be considered in individual distributor system planning processes.[8] Accordingly, these filing requirements provide that where applicable, a distributor file information on the Regional Planning Process(s) in which it was a participant; on the Regional Infrastructure Plan provided by the transmitter; and information demonstrating that the Regional Infrastructure Plan has been appropriately considered and addressed in the development of the distributor's DS Plan.

5.0.3.4 Smart grid development and implementation

Under the renewed regulatory framework, smart grid development is expected to be integral to distribution system plans, a central focus of grid-enhancing innovation, and implemented on a coordinated regional basis to achieve economies of scope and

5 *RRFE Report*; p. 31.
6 *RRFE Report*; p. 31.
7 *RRFE Report*; p. 10.
8 *RRFE Report*; p. 39.

scale.[9] These filing requirements therefore include DS Plan information regarding, where appropriate:

- the activities a distributor has undertaken in order to understand their customers' preferences (e.g., data access and visibility, participating in distributed generation, and load management) and how they have addressed those preferences;
- the options a distributor has considered for facilitating customer access to consumption data in an electronic format;
- the mechanisms that facilitate "real-time" data access and "behind the meter" services and applications that a distributor has considered for the purpose of providing customers with the ability to make decisions affecting their electricity costs;
- the consideration a distributor has given to the investments necessary to facilitate the integration of distributed generation and more complex loads (e.g., customers with self-generation and/or storage capability);
- the technology-enabling opportunities a distributor has considered regarding operational efficiencies and improved asset management; and
- the distributor's awareness and adoption of innovative processes, services, business models, and technologies.[10]

5.0.4 The Board's evaluation of DS Plans

DS Plan filings must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes the Board has established for electricity distributors as explained below. Section 5.4.5 explains the specific criteria the Board will use to evaluate whether a DS Plan and in particular the material[11] projects/activities proposed for cost recovery in a DS Plan address these four outcomes.[12]

Customer Focus

A DS Plan filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences. As indicated in the provisions that follow, this is accomplished by providing information on customer engagement to identify preferences; the value proposition the DS Plan represents for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers and participants in a Regional Planning Process that were considered in the course of planning investment projects and activities.

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[9] See *Report of the Board - Supplemental Report on Smart Grid* (EB 2011-0004); February 11, 2013 (the "*Smart Grid Report*"); pp. 4 – 5.

[10] *Smart Grid Report*; pp. 9 – 16.

[11] A project or activity is "material" if the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* is met.

[12] For details on the evaluation criteria and how the Board will use them to evaluate investments, see the *Smart Grid Report*; pp. 17 – 21.

Operational Effectiveness

DS Plans must show that a distributor's asset management and capital expenditure planning processes are designed to identify and take advantage of opportunities for continuous improvements in productivity and cost performance, while delivering on a distributor's explicitly stated system reliability and quality objectives.

Public Policy Responsiveness

A distributor's DS Plan must explain how the expenditure planning process has been integrated and rationalized so as to permit timely and appropriate expenditures in relation to a distributor's government-mandated obligations (e.g., in legislation or regulatory requirements imposed further to Ministerial directives to the Board).

Financial Performance

DS Plans must show that a distributor's financial viability and operational effectiveness will endure over the long term including by sustaining efficiencies gained through prudent capital-related expenditure planning and DS Plan execution.

5.0.5 Form of these filing requirements

To implement the policy objectives of the renewed regulatory framework, filing requirements related to Distribution System Plans, including information on planned investments related to investments to accommodate the connection of renewable energy generation (REG) and/or smart grid development activities and expenditures (see sections 5.1.2 and 5.0.3.4 respectively), have been consolidated in this Chapter 5 of the Board's *Filing Requirements for Electricity Transmission and Distribution Applications* (*CoS FRs*) Accordingly, these filing requirements replace the Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*.

5.1 General & Administrative Matters

The form and the content of these filing requirements reflect the Board's conclusions in relation to distribution infrastructure planning. These filing requirements introduce a standard approach to a distributor's filings of asset management and capital expenditure plan information in support of a rate application.[13] As detailed in section 5.2, distributors filing a corporate 'Asset Management Plan' are expected to include and

[13] *RRFE Report*; p. 35.

clearly identify in their filings the information set out in these filing requirements, and to use the terminology and formats set out in these filing requirements.[14]

5.1.1 Investment Categories

A distributor's investment projects and activities should be grouped for filing purposes into one of the four investment categories listed below, based on the 'trigger' driver of the expenditure, examples of which are provided on Table 1.

Table 1 – Investment Categories & Example Drivers and Projects/Activities

	Example Drivers	Example Projects / Activities
system access	customer service requests	– new customer connections – modifications to existing customer connections – expansions for customer connections or property development
	other 3rd party infrastructure development requirements	– system modifications for property or infrastructure development (e.g. relocating pole lines for road widening)
	mandated service obligations (DSC; Cond. of Serv.; etc.)	– metering – Long term load transfer
system renewal	assets/asset systems at end of service life due to: – failure – failure risk – substandard performance – high performance risk – functional obsolescence	– programs to refurbish/replace assets or asset systems; e.g: batteries; cable (by type); cable splices; civil works; conductor; elbows & inserts; insulators; poles (by type); physical plant; relays; switchgear; transformers (by type); other equipment (by type)
system service	expected changes in load that will constrain the ability of the system to provide consistent service delivery	– property acquisition – capacity upgrade (by type); e.g. phases; circuits; conductor; voltage; transformation; regulation – line extensions
	system operational objectives: – safety – reliability – power quality – system efficiency – other performance/functionality	– protection & control upgrade; e.g. reclosers; tap changer controls/relays; transfer trip – automation (new/upgrades) by device type/function – SCADA – distribution loss reduction
general plant[1]	– system capital investment support – system maintenance support – business operations efficiency – non-system physical plant	– land acquisition – structures & depreciable improvements – equipment and tools – supplies – finance/admin/billing software & systems – rolling stock – intangibles (e.g. land rights; capital contributions to other utilities)

Note: 1. Includes only 19## series accounts.

[14] For the Board's conclusions in relation to consolidating and harmonizing its planning-related filing requirements see *RRFE Report*; p. 31.

- ***System access*** investments are modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system
- ***System renewal*** investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.
- ***System service*** investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements
- ***General plant*** investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

A project or activity involving two or more 'drivers' associated with different categories should be placed in the category corresponding to the 'trigger' driver. For example, a project triggered by the need to replace end of service life components in a distribution station should be considered a 'system renewal investment, even if in anticipation of future system requirements (a 'system service' driver) the project includes assets rated for a higher voltage and/or capable of handling reverse flows. Note, however (as detailed in section 5.4.5), information on all drivers of a given project or activity should be used to justify proposed capital investments.

5.1.2 Investments related to renewable energy generation

Under the renewed regulatory framework, a distributor's investments to accommodate and connect renewable energy generation (i.e. REG investments) are integral to its DS Plan, which includes all costs to connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the *OEB Act*.

5.1.3 Time of filing

All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application. Distributors proposing to use the 'Annual IR Index' method for 2014 rates are not required to use Chapter 5 when filing an application. However, any distributor using the 'Annual IR Index' method must make a Chapter 5 filing within five years of the date of the most recent Board decision approving their rates in a cost of service proceeding; and is required to do so at five year intervals thereafter while using the Annual IR Index method. The Board may also require a DS Plan to be filed in relation to leave to construct, Incremental Capital Module or Z-factor applications.

5.1.4 Planning in consultation with third parties

5.1.4.1 Regional planning and consultations

Prior to filing a DS Plan and at a time and in a manner to be determined in consultation with the participants in a Regional Planning Process, a distributor must:

1. Provide regionally interconnected distributors (including host and/or embedded where applicable), the transmitter to which the distributor is connected and the OPA (where applicable) with information on:
   - forecast load at existing (and proposed, if any) points of interconnection;
   - forecast renewable generation connections and any planned network investments to accommodate the connections;
   - investments involving smart grid equipment and/or systems that could have an impact on the operation of assets serving the regionally interconnected utilities; and
   - the results of projects or activities involving the study or demonstration of innovative processes, services, business models, or technologies; and on the projects or activities of this nature planned by the distributor over the forecast period.
2. Consult with regionally interconnected distributors (including host and embedded where applicable) and transmitter(s) to which the distributor is connected in preparing their DS Plan.

5.1.4.2 Renewable energy generation investments

Prior to filing a DS Plan, a distributor must:

1. Not less than 60 days (where REG investments are contemplated; 30 days otherwise) in advance of the date the distributor needs to receive the OPA letter for inclusion in an application, a distributor must submit information to the OPA in relation to the REG investments identified in their DS Plan and request in writing that the OPA provide a letter commenting on the information by a date that conforms to the distributor’s filing timetable.
2. The Board expects that the OPA comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

5.1.5 Performance reporting

A distributor is to provide information on its performance in relation to its DS Plan as set out in section 5.2.3, including information on the achievement of the operational or other objectives targeted by investments the costs for which were approved in a previous application(s). Through its RRR filing, a distributor is also required to report annually on its performance, including in relation to reliability and any Performance Scorecard metrics established by the Board, including metrics related to asset management and capital expenditure planning as applicable.

5.2 Distribution System Plans

Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.

5.2.1 Distribution System Plan overview

This section provides the Board and stakeholders with a high level overview of the information filed in the DS Plan, including but not limited to

a) key elements of the DS Plan that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives

b) the sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution

c) the period covered by the DS Plan (historical and forecast years);

d) an indication of the vintage of the information on investment 'drivers' used to justify investments identified in the application (i.e. the information should be considered "current" as of what date?);

e) where applicable, an indication of important changes to the distributor's asset management process (e.g. enhanced asset data quality or scope; improved analytic tools; process refinements; etc.) since the last DS Plan filing; and

f) aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional Planning Process) or event (Board decision on LTLT) and the expected dates by which such outcomes are expected or will be known.

Prior to filing, care should be taken to ensure that summary information is consistent with the detailed information filed in the following sections and elsewhere in the application.

5.2.2 Coordinated planning with third parties

To demonstrate that a distributor has met the Board's expectations in relation to coordinating infrastructure planning with customers, the transmitter, other distributors and/or the OPA or other third parties where appropriate, a distributor must provide:

a) a description of the consultation(s), including

- the purpose of the consultation (e.g. Regional Planning Process);
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process (e.g. customers; transmitter; OPA);
- the nature and prospective timing of the final deliverables (if any) that are expected to result from or otherwise be informed by the consultation(s) (e.g. Regional Infrastructure Plan; Integrated Regional Resource Plan); and
- an indication of whether the consultation(s) have or are expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.

b) where a final deliverable of the Regional Planning Process is available, the final deliverable; where a final deliverable is expected but not available at the time of filing, information indicating:

- the role of the distributor in the consultation;
- the status of the consultation process; and

- where applicable the expected date(s) on which final deliverables are expected to be issued.

c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.3 Performance measurement for continuous improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:

   - customer oriented performance (e.g. consumer bill impacts; reliability; power quality);
   - cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and
   - asset and/or system operations performance.

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

   Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

c) explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

[15] The data should be calculated as stipulated in section 2.1.4.2 of the Board's Reporting and Record Keeping Requirements.

5.3 Asset Management Process

As noted in the Introduction, a distributor's asset management process is the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on its distribution system and general plant. The purpose of the information requirements set out in this section 5.3 is to provide the Board and stakeholders with an understanding of the distributor's asset management process, and the direct links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

5.3.1 Asset management process overview

This section provides the Board and stakeholders with a high level overview of the information filed on a distributor's asset management process, including key elements of the process that have informed the preparation of the distributor's capital expenditure plan and therefore are referred to in response to requirements for more detailed information supporting the overall capital expenditure plan, budget allocations to categories of investments, or material projects/activities proposed for recovery in rates. The information provided should include but need not be limited to:

a) a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;

b) information regarding the components (inputs/outputs) of the asset management process used to prepare a capital expenditure plan, identify and briefly explain the data sets, primary process steps, and information flows used by the distributor to identify, select, prioritize and/or pace investments; e.g.

- asset register
- asset condition assessment
- asset capacity utilization/constraint assessment
- historical period data on customer interruptions caused by equipment failure
- reliability-based 'worst performing feeder' information and analysis
- reliability risk/consequence of failure analyses.

Use of a flowchart illustration accompanied by explanatory text is recommended.

5.3.2 Overview of assets managed

Appropriate regulatory assessment of DS Plans requires an understanding of the scope and depth of the assets managed by a distributor. Distributors vary in terms of the types of assets managed (e.g. some own high voltage equipment; others do not). Detailed characteristics and data on the assets covered by the asset management process are to be filed, including but not necessarily limited to

a) a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;

b) a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;

c) information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled; and

d) an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets

    - where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.

5.3.3 Asset lifecycle optimization policies and practices

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment, and should include but need not be limited to:

a) A description of asset lifecycle optimization policies and practices, including but not necessarily limited to:

    - a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;
    - a description of maintenance planning criteria and assumptions; and

- a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).

b) A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.

5.4 Capital Expenditure Plan

A distributor's DS Plan details the programme of system investment decisions developed on the basis of information derived from its asset management and capital expenditure planning process. It is critical that investments, whether identified by category or by specific project, be justified in whole or in part by reference to specific aspects of that process.

As noted above, a DS Plan must include information on prospective investments over a minimum five year forecast period, beginning with the test year (or initial test year if Customer IR filing), as well as information on investments – planned and actual – over the five year period prior to the initial year of the forecast period.

5.4.1 Summary

This section elicits key information about a distributor's capital expenditure plan including, by category (see section 5.1.1), significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category and a distributor's objectives and targets; and the primary factors affecting the timing of investment in each category (or of projects within each category, if significant).

The following information should be provided:

a) information on the capability of the distributor's system to connect new load or generation customers in sufficient detail to convey the basis for the scope and quantum of investments related to this 'driver';

b) total annual capital expenditures over the forecast period, by investment category (see section 5.4);

c) a brief description of how for each category of investment, the outputs of the distributor's asset management and capital expenditure planning process have affected capital expenditures in that category and the allocation of the capital budget among categories;

d) a list and brief description including total capital cost (table format recommended) of material capital expenditure projects/activities, sorted by category;

e) information related to a Regional Planning Process or contained in a Regional Infrastructure Plan that had a material impact on the distributor's capital expenditure plan, with a brief explanation as to how the information is reflected in the plan;

f) a brief description of customer engagement activities to obtain information on their preferences and how the results of assessing this information are reflected in the plan;

g) a brief description of how the distributor expects its system to develop over the next five years, including in relation to load and customer growth, smart grid development and/or the accommodation of forecasted renewable energy generation projects;

h) a list and brief description including where applicable total capital cost (table format recommended) of projects/activities planned:

- in response to customer preferences (e.g., data access and visibility; participation in distributed generation; load management);
- to take advantage of technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads; and
- to study or demonstrate innovative processes, services, business models, or technologies.

5.4.2 Capital expenditure planning process overview

The information a distributor should provide includes, but need not be restricted to:

a) a description of the distributor's capital expenditure planning objectives, planning criteria and assumptions used, explaining relationships with asset management objectives, and including where applicable its outlook and objectives for accommodating the connection of renewable generation facilities;

b) if not otherwise specified in (a), the distributor's policy on and procedure whereby non-distribution system alternatives to relieving system capacity or operational constraints are considered, including the role of Regional Planning Processes in identifying and assessing alternatives;

c) a description of the process(es), tools and methods (including where relevant linkages to the distributor's asset management process) used to identify, select, prioritise and pace the execution of projects in each investment category (e.g. analysis of impact of planned capital expenditures on customer bills);

d) if not otherwise included in c) above, details of the mechanisms used by the distributor to engage customers for the purpose of identifying their needs, priorities and preferences (e.g. surveys, system data analytics, and analyses – by rate class – of customer feedback, inquiries, and complaints); the stages of the planning process at which this information is used; and the aspects of the DS Plan that have been particularly affected by consideration of this information; and

e) if different from that described above, the method and criteria used to prioritise REG investments in accordance with the planned development of the system, including the impact if any of the distributor's plans to connect distributor-owned renewable generation project(s).

5.4.3 System capability assessment for renewable energy generation

This section provides information on the capability of a distributor's distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable) includes:

a) applications from renewable generators over 10kW for connection in the distributor's service area;

b) the number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the OPA and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown should be provided);

c) the capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area;

d) constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter); and

e) constraints for an embedded distributor that may result from the connections.

5.4.4 Capital expenditure summary

The purpose of the information filed under this section is to provide the Board and stakeholders with a 'snapshot' of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Note that where a distributor's internal investment planning framework does not align with the investment categories defined here, best efforts are expected to 'map' investments to these categories.

Despite the 'multi-purpose' character of a project or activity, for 'summary' purposes the entire costs of individual projects or activities are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or ‘trigger’) driver of the investment. Note, however, that for material projects, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or activity for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC.

Table 2 illustrates how information filed under this section includes a distributor’s actual and forecast (i.e. proposed) capital expenditures over the historical and forecast periods. System operations and maintenance (O&M) costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. Note that ‘Plan’ expenditures over the historical period refer to a distributor’s previous plan for capital expenditures *after* adjustments (if any) occasioned by the Board’s decision on the relevant prior application.

Brief explanatory notes should be provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to ‘actual’ spending over the historical period. For example, a large expenditure over a relatively short period for a ‘one-off’ project (e.g. a distribution station) can cause a temporary ‘step change’ in category C spending compared to the trend in actual expenditures over the historical period.

While year over year ‘Plan vs. Actual’ variances for individual investment categories are expected, explanatory notes should be provided where

- for any given year “Total” ‘Plan’ vs. ‘Actual’ variances over the historical period are markedly positive or negative; or
- a trend for variances in a given investment category is markedly positive or negative over the historical period.

Table 2 – Capital Expenditure Summary

CATEGORY	Historical (previous plan[1] & actual)															Forecast (planned)				
	Test-5			Test-4			Test-3			Test-2			Test-1[2]			Test	Test+1	Test+2	Test+3	Test+4
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000	$ '000	$ '000	$ '000	$ '000
System Access																				
System Renewal																				
System Service																				
General Plant																				
Total																				
System O&M																				

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in year 'Test-1' (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

5.4.5 Justifying capital expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.5.1 Overall plan

The Board's assessment of DS Plans includes the costs of material projects/activities included in the DS Plan, as well as the costs represented by the respective shares of the overall DS Plan budget allocated to each of the four investment categories. Information to be provided in this section pertains to the latter; the former is addressed in section 5.4.5.2.

To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:

- comparative expenditures by category over the historical period;
- the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;
- the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);
- information related to the distributor's system capability assessment (see section 5.4.3)

5.4.5.2 Material investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications*. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g. unique characteristics; marked divergence from previous trend) are supported by evidence that enables the Board's assessment according to the evaluation criteria set out below. The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

A. General Information on the Project/Activity

The following information is to be provided for any material project in order to facilitate and understanding of the quantum of the expenditure, timing, and contingencies associated with the project:

- total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
- related customer attachments and load, as applicable
- start date, in-service date and expenditure timing over the planning horizon
- the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
- if not evident from Table 2, comparative information on expenditures for equivalent projects/activities over the historical period, where available
- information on total capital and OM&A costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities
- 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)

B. Evaluation criteria and information requirements for each project/activity

The Board's evaluation of material investments aligns with the outcomes set out in section 5.0.4. Efficiency, customer value, reliability and safety are the primary criteria for evaluating any material investment; other criteria pertaining specifically to grid modernization will be applied where applicable.

The Board's investment evaluation criteria and the qualitative or quantitative evidence that a distributor can use to demonstrate that an investment is consistent with these criteria are set out below.

1. *Efficiency, Customer Value, Reliability*
    a) identify the main 'driver' ('trigger') of the project/activity, and where applicable any secondary 'drivers'; related objectives and/or performance targets; and by reference to the distributor's asset management process (section 5.3.1), the source and nature of the information used to justify the investment
    b) indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing and pacing projects in each investment category described in response to section 5.4.2(c)

c) using, where applicable, quantitative and/or qualitative analyses of the project and project alternatives involving design, scheduling, funding and/or ownership options (e.g. whole or part ownership solely by or jointly with 3rd parties)

   - explain the effect of the investment on system operation efficiency and cost-effectiveness
   - the net benefits accruing to customers as a result of the investment
   - the impact of the investment on reliability performance including on the frequency and duration of outages

   Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives.

   Where a distributor's choices as to technical design, component characteristics, how the work is carried out, etc. have been affected by a decision to configure a project to meet both a 'trigger' driver and one or more other drivers in a manner that affects cost as well as benefits, these effects should be highlighted.

2. *Safety*

   Provide information on the effect of the investment on health and safety protections and performance

3. *Cyber-security, Privacy*

   Where applicable, provide information showing that the investment conforms to all applicable laws, standards and best utility practices pertaining to customer privacy, cyber-security and grid protection

4. *Co-ordination, Interoperability*

   a) where applicable, explain how the investment applies recognized standards, referencing co-ordination with utilities, regional planning, and/or links with 3rd party providers and/or industry.

   b) describe how the investment potentially enables future technological functionality and/or addresses future operational requirements

5. *Economic Development*

   Where applicable, describe the effect of the investment on Ontario economic growth and job creation

6. *Environmental Benefits*:

   Where applicable, describe the effect of the investment on the use of clean technology, conservation and more efficient use of existing technologies

C. Category-specific requirements for each project/activity

As set out below, category-specific information and analyses should also be used to support a project/activity (or elements thereof as applicable).

a) *System access* – projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to requests by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions.

   In the event that the project involves replacing a distributor's system assets, there may also be asset life-cycle related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

   Information bearing on these issues should therefore be included in a distributor's justification of a project/activity in this category, including (where applicable) but not restricted to:

   - factors affecting the timing/priority of implementing the project
   - factors relating to customer preferences or input from customers and other third parties
   - factors affecting the final cost of the project
   - how controllable costs have been minimized
   - whether other planning objectives are met by the project or have intentionally been combined into the project and if so, which objectives and why
   - whether technically feasible project design and/or implementation options exist, whether these options were considered and if not, why not
   - where such options were considered and project decision support tools and methods described in response to section 5.4.2 (c) were used to help identify the proposed option, provide a summary of the results of the analysis, including where applicable:
     – the least cost option: a comparison of the life cycle cost of all options considered (including the proposed project) – over the service life of the proposed project
     – the cost efficient option: a comparison of net project benefits and costs over the service life of the proposed project including:
       i. a project configured solely to meet the obligation; and

   ii. the proposed project and where considered, technically feasible options to the proposed project that meet the same objectives.

- where applicable, the results of the 'final economic evaluation' carried out as per section 3.2 of the DSC
- where applicable (e.g. REG investment), information on the nature and magnitude of the system impacts of the project, the costs of any system modifications required to accommodate these impacts and the means by which these costs are to be recovered

b) *System renewal* – projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Generally, the lower the former and/or higher the latter, the more important it becomes to replace or refurbish the asset(s) sooner rather than later.

Hence, a distributor's discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority where deteriorating asset condition has little or no impact on performance and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Information bearing on these issues should therefore be included in a distributor's justification of each sustainment project/activity, including (where applicable) but not restricted to:

- a description of the relationship between the characteristics of the assets targeted by a project and the consequences of asset performance deterioration or failure, referring to
  - the distributor's asset performance-related operational targets and asset lifecycle optimization policies and practices (i.e. filings in relation to sections 5.2.3 and 5.3.3)
  - information on the condition of the assets relative to their typical life-cycle; and performance record of the assets targeted by the project
  - the number of customers in each customer class potentially affected by a failure of the assets included in the project
  - quantitative customer impacts (e.g. frequency or duration of interruptions or number of customers affected) with associated risk level(s)
  - qualitative customer impacts (e.g. customer satisfaction; customer migration) with associated risk level(s)

  - the value of customer impact (e.g. high, medium, low) in terms of the characteristics of customers potentially affected by failure that have a bearing on the criticality and/or cost of failure (e.g. customer classes; customer access to backup service)

- other factors that may affect the timing of the proposed project, including the rate at which assets are replaced over the forecast period (i.e. investment intensity), where applicable; priority relative to other projects (this and other categories)
- identify the consequences for system O&M costs, including the implications for system O&M of not implementing the project
- identification of reliability and or safety factors that may have played a role
- where applicable and reasonable variation and/or uncertainty in the above factors exists, provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing alternatives to the timing of the proposed project, highlighting the trade-offs between rate of expenditure and mitigation of the consequences of asset performance deterioration. Where the ranking of the proposed project relative to the alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.
- where the proposed project meets the requirement for ‘like for like’ renewal and has been configured at extra cost to address other distributor planning objectives (e.g. development related objectives), provide – using the tools and methods described in response to section 5.4.2 (c) – an analysis of project benefits and costs comparing a) a project configured solely to meet the requirement; b) the proposed project; and c) technically feasible alternatives to the proposed project that meet the same objectives as the proposed project. Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, these should be described and explained in relation to the proposed project and all alternatives.

c) *System service* – projects/activities in this category are driven by the distributor’s expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor’s service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify projects/activities in this category should include, but need not be restricted to:

- where measurable, an assessment of the benefits of the project for customers in relation to the achievement of the objectives of the investment; express the result (including where value is in the form of an avoided cost) in terms of cost impact to customers where practicable

- where applicable, information on regional electricity infrastructure requirements identified in a regional planning process that affected the initiation or final configuration of the project; and on the corresponding distribution of the benefits and responsibility for project costs
- description of how advanced technology has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.
- identification of any reliability, efficiency, safety and coordination benefits or affects the project will have on the distributor's system
- identifying and explaining the factors affecting implementation timing/priority
- providing, where applicable and using the tools and methods described in response to section 5.4.2 (c), an analysis of project benefits and costs comparing the proposed project to a) doing nothing; and b) technically feasible alternatives to the proposed project considered that meet the same objectives as the proposed project.

  Where the ranking of the proposed project relative to alternatives has been adjusted to account for significant benefits and costs the value of which cannot readily be quantified, information should be provided that describes these 'qualitative' factors in relation to the proposed project and all alternatives, and that explains whether and how these factors affected the selection of the proposed project.

d) *General plant* – projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Information used by a distributor to justify material projects/activities in this category should include but need not be restricted to:

- the results of quantitative and qualitative analyses (using the tools and methods described in response to section 5.4.2 (c) where applicable) of the proposed project/activity, including assessments of financially feasible options to the proposed project (including the 'do nothing option' where applicable), identifying the (net) benefits of the proposed investment in monetary terms where practicable;
- For projects the capital cost of which substantially exceed the materiality threshold, (e.g. CIS, GIS, new office building) the distributor shall file a thorough business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).