Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario Energy Board

Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities

Chapter 2A

Cost of Service

December 16, 2021

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Chapter 2A Filing requirements for electricity distribution cost of service rate applications for small utilities based on a forward test year

2.0 General Requirements

The purpose of this document is to set out the filing requirements for cost of service applications by electricity distributors with less than 30,000 customers. The filing requirements have been established to provide sufficient information to inform the Ontario Energy Board (OEB) and interested parties of all material facts related to the distribution of electricity by an electricity distributor in order to set rates.

These filing requirements provide details of the information the OEB expects in an application for it to be considered complete. If a small utility believes that any of the requirements do not apply to their application, they should clearly set out the reason(s) why.

As the onus is on the applicant to present its own case, small utilities should provide in their application the information necessary to support its request for just and reasonable rates. The level of detail required should reflect the scale of any request. While all components of the application must be justified, the expectation regarding the level of information filed in support should reflect the scale of the request in terms of its materiality, complexity, variance from previous applications or plans, deviation from OEB policy, and impact on revenue requirement and customers' bills.

Applicants are encouraged to structure the evidence in the format presented in Section 2.0.8. Small electricity distributors should endeavor to present a clear, concise application with minimal repetition.

2.0.1 Relevant Chapters

In addition to the Handbook for Utility Rate Applications (the Handbook), which outlines the key principles and expectations of the OEB when reviewing an application, the filing requirements contained in this chapter and Chapter 5A outline all of the relevant information that is necessary for a complete cost of service application. The OEB currently uses three incentive rate-setting (IR) methods: (1) Price Cap IR, (2) Custom IR and (3) Annual IR Index. The Price Cap IR option consists of a cost of service (or rebasing)[1] followed by four years of incentive rate-setting mechanism (IRM) adjustments. In the Custom IR method, rates are set based on a five year forecast of an electricity distributor's revenue requirement and sales volumes. The Annual IR Index method adjusts rates by a simple price cap index formula (i.e. I-X), where the X-factor will be the same as the highest X-factor. All distributors on the Annual IR Index will be subject to the

[1] The OEB considers cost of service and rebasing to be the same and therefore these terms are used interchangeably for the purposes of this chapter.

same X-factor. Filing requirements for IRM applications (i.e. the Price Cap IR and Annual IR Index options) are provided in Chapter 3. Applicants should also review Chapter 1 of this document, which provides an overview of the OEB's expectations on certain generic matters, such as the completeness and accuracy of an application, the exploration of non-material items, and confidential filings. Chapter 1 also contains the requirement that distributors must include a certification by a senior officer of the applicant that the evidence filed, including the models and appendices, are accurate, consistent and complete to the best of their knowledge, as well as a certification regarding personal information.

The OEB posts an updated checklist on its electricity distribution rates web page annually based on these filing requirements. Distributors should file the checklist with their applications. Any deviations from the filing requirements need to be identified and explained.

2.0.2 Appendices and Models

The various appendices and models referenced in this chapter are linked to each of the sections in Chapter 2A and provide schedules to be completed by the applicant to facilitate the filing of all required information (e.g. Appendix 2-K – Employee Costs provides tables related to section 2.4.3.1 – Workforce Planning and Employee Compensation). These appendices and models are available in Excel format on the OEB's website and must be completed by applicants and filed as part of a cost of service application in live Excel format. Applicants must also provide PDF and Excel copies of their current Tariff of Rates and Charges. At the draft rate order stage of a proceeding, or as part of a settlement proposal, if applicable, applicants are required to provide an updated Revenue Requirement Work Form (RRWF). Applicants may also be required to update certain tabs in the Chapter 2 Appendices, if changes to the proposal are made during the proceeding. The required tabs are indicated in the Appendices at the "Index" tab and applicants must file the workbook in its entirety at the draft rate order stage of the proceeding.

The models issued by the OEB are to assist the applicant in filing a rate application and to provide consistent content and format by all distributors. The models will be provided unlocked if the utility prefers this option. If a utility does update or amend an OEB model to accommodate their circumstance, the distributor should make reference in the corresponding Exhibit to what has been updated / amended to assist the parties reviewing the application.

A distributor is responsible for the completeness and accuracy of its application. This includes the responsibility to ensure the accuracy and appropriateness of all inputs and outputs from the models that it uses to support its application. The applicant is also responsible for advising the OEB 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 an OEB-issued model does not necessarily mean that the OEB will approve the results.

2.0.3 Separation of Distribution Function

Distributors are rate-regulated by the OEB on a stand-alone basis, which means that the application must show the regulated entity separately from its parent company or any other affiliates, both regulated and not regulated by the OEB. It is also important that only the amounts attributable to the distributor's regulated activities be reflected when determining matters such as the amount of tax recovery, debt costs, and the cost of affiliate relationship transactions to be recoverable in rates paid by electricity ratepayers.

2.0.4 Consolidation Information

Small electricity distributors must file information on the extent to which they have investigated potential opportunities from consolidation or collaboration/partnerships with other distributors. This requirement is in accordance with the Minister's Letter to OEB Chair[2], applicable to any electricity distributor with less than 30,000 customers. The distributors should also provide any conclusions resulting from any investigations, including plans to explore future opportunities.

2.0.5 Cost of Service Application in Advance of Scheduled Application

Distributors planning to file a cost of service application earlier than scheduled must meet the threshold for early rebasing established in the OEB's letter of April 20, 2010.

2.0.6 Seeking Approval to Align Rate Year with Fiscal Year

Distributors may seek approval to align their rate year with their fiscal year (i.e. January 1). If a January 1 effective date for new rates is being requested, the OEB expects such applications to be filed no later than the end of April of the year prior to the test year, in order to allow sufficient time for the review and processing of the application.

2.0.7 Late Filing of Cost of Service Application

The OEB establishes deadlines for the filing of cost of service applications each year. Distributors who file applications by the required date set out by the OEB, can generally expect to receive the requested effective date, except where delays occur due to the actions of the applicant. The effective date of rates approved for proceedings in which the applicant caused delays, or for applications filed after the required date may be later than the effective date proposed.

[2] Minister's Letter, November 15, 2021

Late applications filed after the commencement of the rate year for which the application is intended will not be accepted by the OEB. For example, for an application to set rates on a cost of service basis commencing May 1, 2023, an application filed after April 30, 2023 (the last business day before the commencement of the rate year) should be converted to a 2024 rate application. This means that the 2023 test year now becomes the bridge year and the applicant should provide a 2024 budget to underpin the updated test year. In this instance, the OEB expects that a distributor will not seek any further rate adjustment for the 2023 rate year but will remain with the rates set for 2022. Applicants for 2024 rates may seek, in this instance, to align their fiscal and rate years.

2.0.8 Structure of Application

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 (includes the Distribution System Plan)
Exhibit 3	Customer and Load Forecast
Exhibit 4	Operating Expenses
Exhibit 5	Cost of Capital and Capital Structure
Exhibit 6	Revenue Requirement and 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 forecast 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 at Tab 3. Applicants may refer to the Chapter 2 Appendices, Tab 4 for a list of key references that underpin many of the filing requirements documented in 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, as described in section 2.2.1, unless an alternative method is documented and justified.
- Total capitalization (debt and equity) must equate to total rate base.
- Data for the following years, at a minimum, must be provided, unless explicitly stated otherwise:
    - Test year = prospective year (calendar year during which new rate year commences)
    - Bridge year = current year (or the year immediately preceding the test year)

  - Three most recent historical years (or for as many years as are necessary to provide actuals back to and including the most recent OEB-approved test year, but not less than three years)
  - Most recent OEB-approved test year

Documents are to be provided in bookmarked and text-searchable PDF format.

If a distributor updates its evidence during the course of the proceeding, the distributor must adhere to Rule 11 of the Rules of Practice and Procedure, and the distributor must ensure that the following models, among others, are updated, as applicable, and the revised data reconcile to each other:

- RRWF
- Tariff Schedule and Bill Impacts Model
- Chapter 2 Appendices
- Electricity Distributor Deferral and Variance Account Review (EDDVAR) Continuity Schedule
- Income Tax/Payments In Lieu of Federal and Provincial Corporate Tax (PILs) Work Form
- Cost Allocation Model
- Retail Transmission Service Rates (RTSR) Model
- Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Model
- Advanced/Incremental Capital Module (ACM/ICM) Model (if applicable)

When filing Excel models, applicants should ensure that any links within these models are broken (e.g. links to other documents that are not filed with the application) and the filed versions of such models should be named so that they can be easily identified.

2.0.9 Materiality Thresholds

The applicant must provide justification for annual changes to its rate base, capital expenditures, and operations, maintenance and administration (OM&A) costs.

The thresholds differ for each applicant, depending on the magnitude of the revenue requirement. A written explanation is required for rate base, capital expenditures, and OM&A costs if the revenue requirement impact of variances exceeds the applicable utility-specific threshold as follows:

- $10,000 for a distributor with a distribution revenue requirement less than or equal to $10 million[3]

[3] The previous $15,000 for a distributor with a distribution revenue requirement less than or equal to $10 million still applies to other applications of the materiality threshold, e.g. DVAs, Z factor and eligible investments for the connection of qualifying generation facilities.

- 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

A distributor may provide additional details below the threshold if it determines that this may be helpful to the OEB.

2.0.10 Accounting Matters

The OEB notes that utilities should have adopted International Financial Reporting Standards (IFRS) for external reporting purposes prior to January 1, 2015, unless they report under United States Generally Accepted Accounting Principles (USGAAP) or Accounting Standards for Private Enterprises (ASPE). For regulatory and ratemaking purposes, the standards are applied differently by the OEB in a number of areas, and are referred to as Modified International Financial Reporting Standards (MIFRS) for those that report under IFRS for external reporting purposes. It is the OEB's expectation that most distributors have previously rebased under MIFRS or other accounting standards after Canadian Generally Accepted Accounting Principles was replaced by IFRS. Distributors that have not rebased under MIFRS are expected to have made regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013, as mandated by the OEB.[4] Distributors that have not previously rebased under MIFRS (and are not reporting under USGAAP or ASPE) should consult previous filing requirements for guidance or contact OEB staff.

2.1 Exhibit 1: Administrative Documents

2.1.1 Table of Contents

The application must contain a Table of Contents listing the major sections and subsections of the application.

2.1.2 Application Summary and Business Plan

The distributor should provide its Business and/or its Strategic Plan. In the absence of a Business Plan or Strategic Plan, the distributor must provide key planning assumptions, a description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term.

The distributor must also provide a brief summary of its application which must include the main requests or proposals in the application with appropriate section references to the application content, as well as the rationale behind each request. The summary must be

[4] OEB's letter regarding Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013, July 17, 2012

written in plain language in a way that is easily comprehensible to customers and include the following:

A. Revenue Requirement

- Service revenue requirement requested for the test year
- Increase/decrease ($ and %) from the most recent approved service revenue requirement
- Schedule of main drivers of revenue requirement changes from the last OEB-approved year

B. Load Forecast Summary

- Load and customer growth (% change kWh, kW and change in customer numbers[5] from last OEB-approved)

C. Rate Base and Distribution System Plan (DSP)

- Summary of the major drivers of the DSP
- Rate base requested for the test year
- Change in rate base from last OEB-approved ($ and %)
- Capital expenditures requested for the test year
- Change in capital expenditures from last OEB-approved ($ and %)

D. Operations, Maintenance and Administration Expense

- OM&A for the test year, and the change from last OEB-approved ($ and %)
- Summary of overall drivers and cost trends

E. Cost of Capital

- A summary table showing the proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital (WACC)
- A statement as to whether or not the distributor is using the OEB's cost of capital parameters (as applicable)
- Summary of any deviations from the OEB's cost of capital methodology

F. Cost Allocation and Rate Design

- Summary of proposed new customer classes and/or customer class definition changes
- Summary of any significant changes proposed to revenue-to-cost ratios and fixed/variable splits
- Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall

G. Deferral and Variance Accounts

- Total disposition ($) including split between Regulated Price Plan (RPP) and non-RPP customers

[5] Please ensure when reporting customer numbers to indicate whether they are year-end or average.

- Disposition period(s)
- Any new Deferral and Variance Accounts (DVAs) requested and any requested discontinuation of existing DVAs

H. Bill Impacts

- Summary of total bill impacts ($ and %) for a residential consumer using 750 kWh, as well as a typical consumer for a distributor's service area for all customer classes. The bill impacts are to be based on commodity rates based on time-of-use and regulatory charges held constant.
- Bill impacts (the bill impacts that result only from distribution cost changes per sub-total A of Tariff Schedule and Bill Impacts spreadsheet model) to be used for the notice of application for a typical residential customer using 750 kWh per month and for a General Service < 50kW customer using 2000 kWh per month on time-of-use pricing and for all other classes. A distributor should also include and propose bill impacts based on alternative consumption profiles and customer groups as appropriate given the consumption patterns of its customers.

2.1.3 Administration

This section must include the following:

- The contact information for the primary contact for the application, who may be a person within the distributor's organization other than the primary licence contact. The primary contact's name, address, phone number, and email address must all be provided. The OEB will communicate with this person during the course of the application.
- Identification of any legal or other representation for the application
- Confirmation of the distributor's internet address for purposes of viewing the application and related documents, and any social media accounts (with addresses) used by the distributor to communicate with its customers.
- A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate. The OEB has implemented a publication process that no longer requires that the distributor publish the notice of hearing. However, the OEB still requires the distributor's recommendation(s) regarding publication media.
- Statement as to the form of hearing requested (i.e. written or oral) and an explanation for the distributor's preference
- The requested effective date
- A statement identifying and describing any changes to methodologies as used in previous applications
- Identification of OEB directions from any previous OEB Decisions and/or Orders (this includes any commitments made as part of an approved settlement). The distributor must clearly indicate how these are being addressed in the current application

- 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. A description of any changes that have been made since the last cost of service application must also be provided. If the Conditions of Service would change as a result of approval of the application, the distributor must also identify all such changes.
- Confirmation that there are no rates or charges listed in the Conditions of Service that are not on the distributor's Tariff of Rates and Charges.
- A description of the corporate and utility organizational structure, showing the main units and executive and senior management positions within the utility. Include a corporate entities relationship chart, showing the extent to which the parent company is represented on the utility company's Board of Directors and a description of the reporting relationships between utility and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control.
- A list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts), new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented in this section. Appendix 2-A is provided for convenience but is not required to be used.

2.1.4 Distribution System Overview

The following information must be filed:

- Description of distributor's service area: general description and map showing where the utility operates within the province and the communities serviced by the utility

2.1.5 Customer Engagement

Distributors should discuss how they communicate with their customers on a regular basis, how the proposals in the application were communicated to customers, any feedback provided in response and how this feedback informed the final proposals included in the application.

Customer consultation for the application should include customers who would be affected by proposals related to new classes, elimination of classes, changes to the definition of classes and changes in charges such as Retail Service Charges, Specific Service Charges and standby rates. Such communication should take place when proposing changes to the level of the rates and charges, or the introduction of new rates and charges.

Further, the OEB expects distributors to document their communications with unmetered load customers, including street lighting customers, and how the distributor assisted them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers.

A formal survey to engage with customers is not a filing requirement for a rate application. However, distributors should also describe communications sent to customers about the application, such as bill inserts, town hall meetings held, or other forms of outreach undertaken to engage customers. The Customer Satisfaction Survey is still required as a component of the utility's scorecard.

Distributors may use Appendix 2-AC – Customer Engagement Worksheet to assist in listing its customer engagement and transactional activities.

This section must also include all responses to matters raised in letters of comment filed with the OEB during the course of the proceeding, when available.

2.1.6 Performance Measurement

Under the renewed regulatory framework (RRF), a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilitate performance monitoring and benchmarking of distributors the OEB uses a scorecard approach.

The Report of the Board on Performance Measures for Electricity Distributors: A Scorecard Approach sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and continuous improvement in achieving the four outcomes which form the basis of the RRF Report.

Along with the scorecard, the OEB publishes a report each year on the benchmarking of electricity distributor cost performance. As described in the OEB's Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, an econometric model is used to generate efficiency rankings of each distributor to one of five groups based on their annually benchmarked cost performance.

In its rate application, a distributor should provide a link to its most recent scorecard. Distributors must identify performance improvement targets, being set by the distributor for itself, that would lead to enhancements to the distributor's scorecard performance over the term of the rate-setting plan. The distributor must also provide the Pacific Economics Group (PEG) forecasting model for the test year which provides a forecast of its efficiency assessment for the purposes of providing the OEB with a directional indication of efficiency. The application should discuss how the results obtained from the PEG forecasting model have informed the distributor's business plan and the application. Distributors may wish to provide a table summarizing their respective OEB approved IRM increases for each of the last historical years between the last rebasing application and the current application, as well as the assigned cohort as per the PEG model for each historical year.

On March 30, 2021 the OEB issued the Activity and Program-based Benchmarking (APB) results. Distributors applying for rates effective May 1, 2022, or later are to review the APB results, discuss their performance for each of the ten programs and provide any immediate remedial actions the distributor is planning to take. Distributors may also include how the APB results will influence future planning.

2.1.7 Facilitating Innovation

On December 8, 2020, section 1 of the *Ontario Energy Board Act, 1998* (the Act) was amended to include a new electricity-related objective for the OEB: to facilitate innovation in the electricity sector. This change adds a new dimension to the OEB's consideration of applications and raises prospects for more cost-effective services that better meet the needs of customers. This new objective works with the other, existing objectives under the Act and the OEB will continue to evaluate proposals in light of all of the OEB's objectives.

Panels of OEB Commissioners will continue to make determinations which establish rates that are just and reasonable and which are made on the basis of evidence before them. In its consideration of innovation by licensed electricity distributors, the OEB will also continue to have regard to the restrictions on business activity laid out in section 71 of the Act, which prohibits these entities (and transmitters) from undertaking non-utility activities within the utility business, subject to certain exceptions. A distributor may wish to refer to the OEB's Innovation Sandbox to discuss innovative approaches, and to obtain customized guidance. If distributors engage in activities that fall within the parameters set out in section 71(2), (3) or (4) of the Act, those non-distribution activities must be accounted for separately from distribution activities to assist the OEB in ensuring that costs related to these non-distribution activities are not included in rates.

Distributors are encouraged to include in their cost-based applications a description of the ways that their approach to innovation have shaped the application. This could include an explanation of its approach to innovation in its business more generally, or related to specific projects or technologies, including enabling characteristics or constraints in its ability to undertake innovative solutions, for enhancing the provision of distribution services in a way that benefits customers, or facilitating its customer's ability to innovate in how it receives electricity services. Distributors could also include an explanation of how innovative alternatives have been considered in place of traditional investments.

2.1.8 Financial Information

This section must include the following:

- Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate-regulated) for the most recent three historical years (i.e. one year's statement must be filed, covering two years of historical actuals). If the most recent final historical audited financial statements are not available at the time the application is filed, draft financial statements must be filed and the final audited financial statements must be provided as soon as they are available. Alternatively, if the electricity distributor publishes its financial statements on its website, a link to the website can be provided.
- Annual Report and Management's Discussion and Analysis for the most recent year of the distributor and of the parent company, as available and applicable
- Rating agency report(s), if available
- Prospectuses, information circulars, etc. for recent and planned public debt or equity offerings
- Any change in tax status (e.g. from a corporation to a limited partnership)
- A description of existing accounting orders and list of any departures from these orders
- Any departures from the Uniform System of Accounts (USoA)
- The accounting standard(s) used for general purpose financial statements and when they were adopted

If a distributor is conducting non-distribution 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 OEB's Guidelines: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities G-2009-030*0*, September 15, 2009, or any successor document.

2.1.9 Distributor Consolidation

If a distributor has become party to a proposed or approved Merger, Amalgamation, Acquisition, or Divestiture (MAADs) transaction with any other distributor(s) since its last rebasing application, it should disclose this information in the application. These distributors should refer to the Handbook to Electricity Distributor and Transmitter Consolidations, issued on January 19, 2016 for information regarding the OEB's policy on rebasing after consolidation.

A distributor that is filing an application to rebase following a consolidation must:

- Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs (e.g. programs, projects and/or assets) that are being proposed to remain in or be entered into rate base and/or revenue requirement.
    - List the exhibits of its application in which any such incentives are discussed.

- Specify whether and which commitments made to shareholders are to be funded through rates.
- Detail the realized and projected savings resulting from the consolidation compared to what was in the approved consolidation application and explain the nature of these savings (e.g., whether one time, ongoing, sustainable).
- Detail the efficacy of any rate plan confirmed as part of a MAADs application.
- Identify approved ACMs or ICMs from a previous Price Cap IR application it proposes be incorporated into rate base.

2.2 Exhibit 2: Rate Base

2.2.1 Rate Base

Distributors should indicate whether capital expenditures are equivalent to in-service additions and if so, then variance explanations are only required once.[6] Applicant should specify whether it is explaining variances based on capital expenditures or in-service additions.

For rate base, the distributor must include the opening and closing balances for each year, and the average of the opening and closing balances for gross fixed assets and accumulated depreciation. If a distributor uses an alternative method, such as calculating the average in-service fixed assets based on the average of monthly or quarterly values, it must document and justify the methodology used. Rate base may also include an allowance for working capital (described below).

This section must include a table showing the components of the last OEB-approved rate base, the proposed test year rate base and the variances.

2.2.2 Fixed Asset Continuity Schedule

The information outlined in Appendix 2-BA must be provided for each year, in Excel format.

Continuity statements and year-over-year variance analyses must be provided. Continuity statements must provide year-end balances and include any capitalized interest during construction and any capitalized overhead costs. Written explanations must be provided where there is a year-over-year variance greater than the applicable materiality threshold.

If continuity statements have been restated for the purposes of the application (e.g. changes in accounting standards or policies, or to reflect corrections in historical audited

[6] Capital in service additions in year X = Capital expenditures in year X + Construction Work in Progress (CWIP) in year X-1 - CWIP in year X

values), the utility must provide an explanation for the restatement and also provide a reconciliation to the original statements.

The following comparisons must be provided:[7]

- Historical OEB-approved vs. historical actual (for the most recent historical OEB-approved year)
- Historical actual vs. preceding historical actual (for the relevant number of years)
- Historical actual vs. bridge
- Bridge vs. test year

The opening and closing balances of gross fixed 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 distributor must provide an explanation and reconciliation. This reconciliation must be between the December 31, 2022 and December 31, 2023 net book value balances reported on the Fixed Asset Continuity Schedule (Appendix 2-BA) 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 Construction Work in Progress (CWIP) and Asset Retirement Obligations (AROs).

A distributor may include in-service balances previously recorded in deferral or variance accounts, such as MIST[8] meters or renewable generation/smart grid related accounts, in its opening test year PP&E balances, if these costs have not been previously reviewed and approved for disposition and disposition is being requested in this application. This may result in opening balances not reconciling to the closing bridge year PP&E balances. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation.

2.2.3 Gross Assets – Property Plant and Equipment and Accumulated Depreciation

The distributor must provide the following information:

- Breakdown by function (transmission or high voltage 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

[7] ACM/ICM assets to be included in the in-service year

[8] "MIST meter" means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to "Metering Inside the Settlement Timeframe".

- Summary of any ACM or ICM adjustment(s), including what was approved and what was spent, if the distributor received approval for an ACM or ICM adjustment as part of a previous IRM application

Continuity statements must be reconcilable to the calculated depreciation expenses, and presented by asset account. Further guidance is included in the filing requirements appendices spreadsheets and under section 2.2.

The distributor must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historical, bridge and test years.

2.2.4 Depreciation, Amortization and Depletion

Applicants must demonstrate that the proposed levels of depreciation/amortization expense appropriately reflects the useful lives of the utility's assets and the OEB's accounting policies.

The Kinectrics Report[9] provides information that the OEB expects distributors will consider as they develop asset service lives to be included in their cost of service applications. However, while the Kinectrics Report contains a range of useful lives for assets, distributors must ensure that these ranges (and the specific useful lives selected within the ranges) are appropriate to their circumstances when preparing an application, and must provide explanations and support for any proposed useful lives that are not within the ranges contained in the Kinectrics Report.

The information outlined below is required for depreciation, amortization and depletion:

- Details for depreciation, amortization and depletion by asset group for the historical, bridge and test years, including asset amounts and rates of depreciation or amortization. The applicant must file the applicable depreciation appendix as provided in the Chapter 2 Appendix 2-C. These must reconcile with the accumulated depreciation balances in the fixed asset continuity schedule (Appendix 2-BA) under rate base.
- The applicant must identify any AROs and any associated depreciation or accretion expenses related to the AROs, including the basis for and calculation of these amounts.
- The OEB's general policy for electricity distribution rate setting has been that capital additions would normally attract six months of depreciation expense when they enter service in the test year.[10] This is commonly referred to as the "half-year" rule. Distributors can propose a different approach in their applications for the OEB's consideration, but must identify their historical practices and must

[9] EB-2010-0178, Asset Depreciation Study for Use by Electricity Distributors (the Kinectrics Report), July 8, 2010

[10] *Report of the Board: 2006 Electricity Distribution Rate Handbook* (RP-2004-0188), May 11, 2005, p. 15 (regarding the ½ year treatment for new in-service additions)

support any variance from the half-year rule whether that variance applies to just the test year, subsequent years, or both.
- 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. 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 components of each item of PP&E are being depreciated separately, in accordance with its adopted accounting standard. Any deviations from this practice must be explained.

A distributor that has not made any changes to its depreciation policy or asset service lives since its last rebasing application must state that this is the case. For a distributor that has made any depreciation policy or asset service lives changes since its last rebasing application, the following is required:

- Identification of the changes and a detailed explanation for the causes of the changes
- The applicant must use the OEB-sponsored Kinectrics Report or provide its own study to justify changes in useful lives.
- The applicant must provide a list detailing all asset service lives and reconcile this list to the USoA. The applicant must detail differences between its asset service lives and the Typical Useful Lives (TULs) from the Kinectrics Report and provide a detailed explanation for using a service life that is outside the minimum and maximum TULs in the Kinectrics Report. A completed Appendix 2-BB must be filed if there have been changes in asset service lives since the applicant's last rebasing application.

2.2.5 Allowance for Working Capital

In a letter dated June 3, 2015, the OEB provided an update to the OEB's policy for the calculation of the allowance for working capital. The distributor may take one of two approaches for the calculation of its allowance for working capital: (1) use the default allowance of 7.5% of the sum of Cost of Power (CoP) and OM&A or (2) file a lead/lag study.

If the distributor has been directed by the OEB to undertake a lead/lag study as part of its last rate application, it must comply with that order.

The lead/lag study will include a lead/lag 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)
- 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 dollar-weighted. The dollar-weighted net lag (i.e. lag minus lead) is then divided by 365 (366 in a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. This amount is included in the distributor's rate base determination. The lead/lag study should reflect the distributor's actual billing and settlement processing timelines as well as consider relevant changes to the operating environment.

The commodity price estimate used to calculate the CoP must be determined by the split between RPP and non-RPP Class A and Class B customers based on actual data and using the most current RPP (TOU) prices established for the November 1, 2021 to October 31, 2022 period.[11] The calculation must include the impact of the most up to date Ontario Electricity Rebate, currently set at of 17.0% on the total bill. Distributors must complete Appendix 2-Z – Commodity Expense.

The calculation must use the most recent approved Uniform Transmission Rates (UTRs), Smart Metering Entity charge and regulatory charges.

2.2.6 Distribution System Plan

Distributors must file a consolidated DSP in accordance with Chapter 5. All elements of the DSP must be contained in one integrated and cohesive document that contains each of its prescribed components. The DSP must be filed as a stand-alone and self-sufficient element within Exhibit 2. Most distributors in recent years have found it convenient to file the DSP as an appendix to Exhibit 2.

2.2.7 Policy Options for the Funding of Capital

On September 18, 2014, the OEB issued the Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module[12] (the ACM Report). The ACM reflects an evolution of the ICM adopted by the OEB in 2008.

The ACM expands the ICM concept to incorporate the concept of recovery for qualifying incremental capital investments during the Price Cap IR period with an opportunity to identify and pre-test such discrete capital projects documented in the DSP as part of the cost of service application.

As part of a cost of service application, a distributor may propose qualifying ACM capital projects that are expected to come into service during the subsequent Price Cap IR term. These will be discrete projects as documented in the DSP. The distributor must establish the need for and prudence of these projects based on DSP information. The distributor must also identify that it is proposing ACM treatment for these future projects, and provide

[11] Regulated Price Plan Price Report November 1, 2021 to October 31, 2022 issued on October 21, 2021.

[12] EB-2014-0219

the preliminary cost information and ACM/ICM materiality threshold calculations to show that these would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application. The ACM Report provides further details on the information required. A distributor applying for an ACM must file the completed spreadsheet: Capital Module Applicable to ACM and ICM.

The timing and actual amount of the rate riders used to recover the costs of qualifying ACM projects in the subsequent Price Cap IR period will not be determined in the cost of service application. This determination will be made in the Price Cap IR application for the year in which the capital investment will be made and the project comes into service. At that time, the distributor must file updated information on the forecasted costs and demonstrate that the capital project still qualifies for incremental capital funding and recovery. The distributor must also provide its most recent calculation of its regulated return at the time of the applicable Price Cap IR application in which funding for the project, and recovery through rate riders, would commence. If the achieved regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, that distributor does not qualify for funding for an incremental capital project. Therefore, any approvals provided for an ACM in a cost of service application will be subject to the distributor passing the means test in order to receive its funding during the IR term. The distributor must also provide explanations for material variances between actual and forecasted costs (and timing, if applicable). However, the nature and need for the project will be determined as part of the ACM in the cost of service application so it is considered as part of the overall DSP for the utility.

Capital projects not anticipated at the time of the DSP or for which cost forecasts are not sufficiently robust may still qualify for ICM treatment. Such projects may be proposed in a subsequent Price Cap IR application and will be thoroughly tested at that time.

On January 22, 2016, the OEB issued the Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report. This report made changes to the materiality threshold on which ICM and ACM proposals are assessed, but otherwise does not alter the requirements for ACM and ICM proposals by a distributor. The Supplemental Report also reaffirms the applicability of the half-year rule for determining the return on capital in the first year that assets enter service.

2.2.8 Addition of Previously Approved ACM and ICM Project Assets to Rate Base

Any distributor that has an approved ACM or ICM from a previous Price Cap IR application must file a schedule of the ACM/ICM capital asset amounts (i.e. PP&E and associated depreciation) it proposes to be incorporated into rate base. The distributor must compare actual capital spending with the OEB-approved amount and provide an explanation for variances. The OEB will make a determination on any true-up treatment for variances between forecast and actual capital spending during the IRM plan term.

A distributor should record actual amounts in the following sub-accounts of Account 1508 – Other Regulatory Assets in accordance with the OEB's March 2015 Accounting Procedures Handbook (APH) Guidance[13]:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures
- Account 1508 – Other Regulatory Assets, Sub-account Depreciation Expense
- Account 1508 – Other Regulatory Assets, Sub-account Accumulated Depreciation
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues

The distributor should also record monthly carrying charges in the following sub-accounts. Carrying charges are calculated using simple interest applied to the monthly opening balances and recorded in the following sub-accounts:

- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures, Carrying charges
- Account 1508 – Other Regulatory Assets, Sub-account Incremental Capital Expenditures Rate Rider Revenues, Carrying Charges

The rate of interest should be the rate prescribed by the OEB for deferral and variance accounts for the respective quarterly period as published on the OEB's website.[14]

If the OEB determines that a true-up of variances is required, the recalculated revenue requirement relating to the OEB-approved ACM/ICM capital expenditures should be compared to the rate rider revenues collected in the same period and the variance will be refunded to or collected from customers through a rate rider.

The impacts of accelerated capital cost allowance (CCA) should not be reflected in an ACM revenue requirement proposal associated with these projects. The OEB will assess the impact of the accelerated CCA on all capital investments at the time of rebasing to minimize the complexity of the review. Distributors should include the impact of the CCA rule change associated with any ACM projects that are approved for ACM treatment in Account 1592 - PILs and Tax Variances – CCA Changes. The use of this sub-account is outlined in the OEB's July 25, 2019 letter, which is described in section 2.6.2.1. Disposition of amounts tracked in the applicable Account 1592 CCA sub-account should be brought forward at the time of a distributor's next rebasing.

The materiality criteria for an ACM includes a requirement that any incremental capital amounts must clearly have a significant influence on the operation of the distributor. The OEB may take the accelerated CCA into consideration in assessing the impact of the

[13] See Accounting Procedures Handbook, March 2015 Guidance #13, 14 for details on accounts and related journal entries.

[14] See section 7.5 of the *Report of the Board - New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued September 18, 2014 for more details.

proposed capital project(s) on the operations of the utility in determining if ACM/ICM funding is warranted.

2.2.9 Capitalization Policy

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

Per the OEB's letter of July 17, 2012, electricity distributors that elected to remain on CGAAP in 2012 must have implemented regulatory accounting changes for depreciation expense and capitalization policies by January 1, 2013. These accounting changes must be implemented consistent with the OEB's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board on Transition to International Financial Reporting Standards,[15] the Kinectrics Report, and the APH.

Since most of the scheduled cost of service filers for 2023 last rebased in 2018, most distributors will already have reflected in their rates updates to depreciation expense and capitalization policies, in accordance with MIFRS, in a previous rebasing application. If the distributor has changed its capitalization policy since its last rebasing application, the distributor must identify any change(s) and the reason(s) for the change(s).

2.2.10 Capitalization of Overhead

The distributor must complete Appendix 2-D regarding overhead costs on self-constructed assets.

Burden Rates

The distributor 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 distributor must identify the burden rates prior to the change.

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

See Appendix A.

[15] EB-2008-0408

2.3 Exhibit 3: Customer and Load Forecast

This exhibit includes evidence on the distributor's forecast of charge determinants/billing determinants (i.e. customers,[16] energy and load), and variance analyses related to these items.

2.3.1 Load Forecasts

The distributor must provide a weather normal load forecast. A table outlining any factors that influence the load forecast in its service territory should be included. This table could include, but is not limited to factors such as demographics, customer composition, energy conservation and presence of wholesale market participants. If a factor is identified as not applicable, no further explanation on that factor is required.

The distributor should 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 and other variables used in forecasting volumes). The distributor must also provide an explanation of the weather normalization methodology used. Generic load profiles and universal normalization methods may not reflect the unique customer mix, weather and economic activities of a utility's service territory.

A distributor must complete Appendix 2-IB – Actual and Forecast Load and Customer Data. The customer/connection and load forecast for the test year must also be entered on a new tab of the Revenue Requirement Work Form, Sheet 10: Load Forecast.

Two types of load forecasting models have generally been filed with the OEB in previous cost of service applications. These are Multivariate Regression and Normalized Average Use per Customer (NAC) models. While the distributor is not restricted to using these approaches, the following information is required for these two modelling methodologies, when used.

2.3.1.1 Multivariate Regression Model

The following must be provided:

- If the proposed model's methodology differs from the methodology used in the most recent load forecast, the LDC must provide its rationale to support the change. A discussion of modelling approaches considered and alternative models tested must be provided.
- Statistics of the regression equation(s) coefficients and intercept (e.g. associated t- statistics; model statistics including R^2, adjusted R^2, F-statistic, Root-Mean-Squared-Error). The distributor is to explain any resulting non-intuitive

[16] Customer numbers must be identified as representing either year-end numbers or the annual average.

relationships (e.g. negative correlation between load growth and economic growth, load growth and customer growth, etc.)

- Explanation of the weather-normalization methodology including:
    - o If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) used to determine normal weather: the monthly HDD and CDD are based on either: a) 10-year average or b) the distributor's proposed alternative approach, which must be supported with evidence.
  - o Definitions of HDD and CDD, including:
    - o Climatological measurement point(s) (i.e. identification of Environment Canada weather station(s)) and why these are appropriate for the distributor's service territory
    - o Identification of base degrees from which HDDs and CDDs are measured (e.g. 18° C or other)
- 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. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling.
- Any binary variables used (e.g., to account for individual data points, to account for seasonal or cyclical trends, to account for discontinuities in the historical data) must be explained and justified. The use of binary variables should be limited, and overlap with other variables should be avoided (e.g. including seasonal binary variables along with HDD and CDD).
- Explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total.
- Description of how Conservation and Demand Management (CDM) impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including the CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast.

Data and regression model and statistics used in the customer and load forecast must be provided in working Excel format. This would include showing the derivation of any constructed variables.

2.3.1.2 Normalized Average Use per Customer Model

The following must be provided:

- If the model used differs from the method used in the most recent load forecast, rationale to support the NAC methodology chosen

- Data supporting the calculation of NAC values used in the application for each rate class
- Description of how CDM impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including the CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast
- Discussion of weather normalization considerations taken into account in developing the NAC forecast

2.3.1.3 CDM Adjustment for the Load Forecast for Distributors

A new CDM framework was established by the IESO for the 2021-2024 period. The OEB intends to provide more direction regarding Lost Revenue Adjustment Mechanism (LRAM) and load forecasting treatment for savings from the 2021-2024 CDM Framework in a future update[17] to the Guidelines for Electricity Distributor Conservation and Demand Management[18] (CDM Guidelines).

The CDM Guidelines allow distributors to integrate an adjustment into the 2023 load forecast that takes into account CDM impacts. Distributors should ensure that it has fully considered measured impacts persisting from prior years within its load forecast. Distributors should make sure results from January 2015 to April 2019 are consistent with the results provided by the IESO. For 2015 to 2017 program years, the IESO annual verified results provide all the data necessary. For results between 2018 and April 15, 2019, distributors should rely on the monthly Participation and Cost Reports made available by the IESO.

If a distributor expects impacts from any CFF-related projects not deployed by April 15, 2019 but for which a distributor was contractually obligated to complete, or for other programs delivered by the distributor after April 15, 2019, a distributor may include these amounts as part of a CDM manual adjustment to the 2023 load forecast but must ensure that sufficient supporting evidence is provided for all estimated CDM savings.[19]

CDM manual adjustments relate only to CDM savings not included in the historical data used to estimate the load forecast model or, in the case of the regression model, not included in the forecast values for the explanatory variables used. In the event a distributor proposes a CDM adjustment to its 2023 load forecast, it should document the CDM savings to be used as the basis for the 2023 LRAM Variance Account (LRAMVA) threshold. 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 to a customer class, kW. The distributor should document its proposal

[17] EB-2021-0106, OEB Staff Discussion Paper: Updating the Conservation and Demand Management Guidelines for Electricity Distributors
[18] EB-2014-0278, December 19, 2014, updated August 11, 2016
[19] The same treatment may apply for any distributor-led CDM activities.

adequately, including how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. 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.

2.3.2 Accuracy of Load Forecast and Variance Analyses

Appendix 2-IB must be completed and the distributor must provide the following analyses:

- For customer / connection counts:
  - Identification as to whether customer/connection count is shown in year-end or year average format
  - Year-over-year variances in changes of customer/connection counts, with explanations for changes in the definition of, or <u>major</u> changes in the composition of, each customer class. Major changes would include material loss, gain or re-classification of customers in one or more customer classes
  - Explanations of the bridge year and test year forecasts by rate class
  - For the last cost of service rebasing, variance analysis between the last OEB-approved and the actual results. Explanations for material differences should be provided
- For consumption and demand:
  - Explanation, and details as necessary, to support how kWh are converted to kW for applicable demand-billed customer classes
  - Year-over-year variances in consumption (kWh) and demand (kW or Kilo Volts Amps (kVA)) (the latter for demand-billed classes) by rate class and for system consumption (kWh) overall, with explanations for material changes in the definition of, or <u>major</u> changes over time. This comparison should be done for both:
    - Comparison of historical actuals against each other
    - Comparison of historical weather-normalized actuals over time
  - Explanations of the bridge year and test year forecasts by rate class should be provided. Such analysis and explanation should document how these vary from or are trending from both historical actuals and from weather-normalized actuals
  - For the last cost of service rebasing, variance analysis between the last OEB-approved and the actual results. Explanations for material differences should be provided.

Appendix 2-IA provides further instructions for filling out Appendix 2-IB.

All data and equations used to determine the customers/connections, demand and load forecasts must be presented and filed in a live Excel spreadsheet format.

2.4 Exhibit 4: Operating Expenses

2.4.1 Overview

The overview should provide a brief explanation (quantitative and qualitative) of the following:

- OM&A test year levels
- How the distributor develops and receives approval for their OM&A budget (e.g. top down/bottom-up comparison to previous year with adjustments for new or removed expenses)
- Associated cost drivers and significant changes that have occurred relative to historical and bridge years
- Overall trends in costs, and relevant metrics including OM&A per customer (and its components), for the historical, bridge and test years, as discussed above
- Inflation rate assumed. The OEB determines and publishes an appropriate inflation rate (the Input Price Index or IPI) for use by utilities with respect to IRM rate applications; distributors filing cost of service applications should be mindful of this rate, and, if proposing to use a different inflation rate in support of their proposed OM&A, should provide a full explanation supporting their proposal.
- Business environment changes

2.4.2 OM&A Summary and Cost Driver Tables

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

- Summary of Recoverable OM&A Expenses (Appendix 2-JA)
- Recoverable OM&A Cost Driver Table (Appendix 2-JB)
- OM&A Programs Table (Appendix 2-JC) or OM&A by USoA Table (Appendix 2-JD)
- Recoverable OM&A Cost per Customer and per Full Time Equivalent (FTE)(Appendix 2-L)

Appendix 2-JC must be filed to provide OM&A details and variance analysis on a program basis. It is recognized that for some utilities which utilize only a limited number of USoA accounts that single USoA accounts may be the equivalent of a program. For clarity, utilities should provide for each program, a definition of the USoA accounts included.

For distributors that elect to file by USoA, Appendix 2-JD must be filed. The table provided, 2-JC or 2-JD, must reflect the entire amount of OM&A proposed to be recovered through rates, and distributors must provide information for the bridge and test years. Appendix 2-JB should be used to provide information on the cost drivers of OM&A expenses. All distributors must file all remaining OM&A appendices, including Appendix 2-JA that breaks down the OM&A amount into major categories (Operations, Maintenance, etc.). Appendix 2-L normalizes OM&A and some of its subcomponents from Appendix 2-JA by customers and FTEs.

The distributor must identify the overall level of increase (decrease) in OM&A expense in the test year in relation to any decrease (increase) in capitalized overhead.

2.4.3 OM&A Variance Analysis

Distributors must complete the revised Appendix 2-JC – OM&A Programs Table (or 2-JD – OM&A by USoA). At a minimum, this will include the following variance analysis:

- Test Year vs Historical OEB-Approved[20]
- Historical OEB-Approved vs Historical Actuals (for the most recent Historical OEB-Approved year)
- Test Year vs Bridge Year

The materiality threshold applies to USoA accounts if using Appendix 2-JD or details of the OM&A programs if using Appendix 2-JC. If a distributor opts to detail OM&A expense on a USoA basis, the accompanying variances analysis and explanation should be broken down by the five major OM&A categories as per Appendix 2-JA (i.e., Operations, Maintenance etc.).

The variance analysis should include an explanation of whether the change was within the distributor's control or not. Although not all historical years are required, distributors are encouraged to provide explanations for costs above the threshold which have impacted its historical trend.

2.4.3.1 Workforce Planning and Employee Compensation

The distributor must complete Appendix 2-K – Employee Costs in relation to employee complement, compensation and benefits. Information on labour and compensation must include the total amount, whether expensed or capitalized. Where there are three or fewer employees in any category, the distributor 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 OEB expects that distributors will provide a description of their proposed workforce plans, including compensation strategy and any changes from the previous plan. Distributors must discuss the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material

[20] For utilities with revenue requirement less than $10M, the $10k materiality threshold for variance analysis in Section 2.0.9 can be applied annually such that for example over a five year term the variance to be explained from last approved/actual to test year is $10k x 5 years = $50k.
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changes to FTE numbers and compensation. A complete explanation for all years includes:

- Variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees
- Basis for performance pay, eligible employee groups, goals, measures, and review processes for any pay-for-performance plans
- Any relevant studies conducted by or for the distributor (e.g. compensation benchmarking)

The distributor must provide details of employee benefit programs, including pensions, other post-employment retirement benefits (OPEBs), and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years. The most recent actuarial report(s) must be included in the pre-filed evidence. What is documented in the tax section of the evidence must agree with this analysis.

Distributors that are virtual utilities (i.e. utilities that have outsourced all or the majority of functions, including employees, to affiliates) must also complete this appendix in relation to the employees of the affiliates 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.

The OEB initiated a consultation[21] on the regulatory treatment of pension and OPEB costs in May 2015. On September 14, 2017, the OEB issued its report on Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs. A distributor is to be guided by this report in determining its pension and OPEB costs that it is requesting be recovered through rates in its application. The distributor must clearly indicate if pension and OPEB costs are proposed to be recovered using the default accrual basis or the cash basis. If a distributor is proposing to include pension and OPEB expenses based on the cash method, distributors must provide sufficient supporting rationale and evidence for adopting the cash method. If a distributor is proposing to change the basis in which pension and OPEB costs are included in OM&A from its last rebasing application (e.g. from cash to accrual) it must quantify the impact of the transition. For all circumstances, the applicant must file the evidence required by the OEB to support the quantum.

2.4.3.2 Shared Services and Corporate Cost Allocation

Shared Services are ‘shared corporate services’ as defined in the Affiliate Relationships Code (ARC). The applicant must identify all shared services among the affiliated entities, including the extent to which a distributor is a virtual utility and justify its proposed shared services and corporate cost allocation in detail.

[21] EB-2015-0040

For shared services among affiliated entities, a distributor must provide at a minimum:

- The type of service provided or received
- The pricing methodology (e.g. cost-base, market-base, tendering, etc.)

Corporate Cost Allocation is an allocation of costs for corporate and miscellaneous shared services from the parent company to the utility (and vice versa). The applicant must provide at a minimum:

- A list of shared services
- The allocation methodology
- A list of costs and allocators and an explanation of how the distributor derived the allocator
- Any third party review of the corporate cost allocation methodology used

Applicants should ensure and be able to demonstrate their approach to corporate cost allocation and shared services results in no more costs being allocated to the distributor than if it was operating as a stand-alone entity.

The applicant must complete Appendix 2-N in relation to each service provided or received for historical actuals and for 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 OEB-approved
- Test year vs. most recent actuals

The applicant must identify any Board of Directors-related costs for affiliates that are included in the utility's own costs.

Please see section 2.6.3 – Other Revenue above for an overview of items that the applicant must address related to its affiliate transactions and the associated required regulatory accounting practices, distribution rate treatments, and adherence to the ARC.

2.4.3.3 Purchases of Non-Affiliate Services

A distributor 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 material transactions that are not in compliance with the applicant's procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, the applicant must provide an explanation as to why this was the case, as well as the following information for these transactions:

- Summary of the nature and cost of the product or service that is the subject of the transaction (Note that if there are concerns regarding including the cost then confidentiality procedures should be followed)
- A description of the specific methodology used for selecting the vendor, including a summary of the tendering process/cost approach, etc.

2.4.3.4 One-time Costs

The OEB notes that cost of service applications contain costs that, once approved, are recovered annually over the five-year period for which the base rates, as adjusted during the IRM term, remain in effect. Accordingly, 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 (i.e. amortization of the cost recovery over the normal five-year period), an explanation must be provided.

2.4.3.5 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 incremental level of the costs associated with the preparation and review of the current application. In addition, the applicant must identify 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 Price Cap IR option (i.e. five years), for the reasons provided in section 2.4.3.4 above. If the applicant is proposing a different recovery period, it must explain why it believes this is appropriate. Costs that are being claimed on an amortized basis should not be included in historic/bridge years.

2.4.3.6 Low-income Energy Assistance Programs (LEAP)

As set out in the Report of the Board on Low Income Energy Assistance Program (the LEAP Report), the OEB determined that the greater of 0.12% of a distributor's OEB-approved distribution revenue requirement, or $2,000, is a reasonable commitment by all distributors to emergency financial assistance. For greater clarity, OEB-approved total distribution revenue means a distributor's forecasted service revenue requirement as approved by the OEB. A distributor must include the relevant LEAP amount as part of its OM&A expenses in its initial application, which should be updated at the draft rate order stage.

Applicants may propose a LEAP fund higher than 0.12% if its demographics might lead to greater need. Details of those demographics should be provided.

The LEAP amount is to be recovered from all rate classes based on the respective distribution revenue of each of those rate classes.

2.4.3.7 Charitable and Political Donations

The recovery of charitable donations through regulated rates is not allowed, 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 2.4.3.6 above). Applicants must provide detailed information for all contributions that are claimed for recovery.

The applicant must also confirm that no political contributions have been included for recovery.

2.4.4 Conservation and Demand Management

Historically, CDM activity has been predominately funded through programs contracted with the IESO and funded through the Global Adjustment (GA) mechanism, and therefore costs directly attributable to these CDM programs (e.g. staff labour dedicated to such programs) must not be included in the revenue requirement to be recovered through distribution rates. An application must provide a statement confirming that no such costs are included in the revenue requirement. Conservation programs funded per the DSP are included in the revenue requirement.

A new CDM framework has been established by the IESO for the 2021-2024 period. The OEB intends to provide more direction regarding potential costs incurred by distributors from the 2021-2024 CDM Framework in a future update to the CDM Guidelines.

2.5 Exhibit 5: Cost of Capital and Capital Structure

The OEB's general guidelines for cost of capital in rate regulation are currently provided in the Report of the OEB on the Cost of Capital for Ontario's Regulated Utilities[22] (the 2009 Report), issued December 11, 2009.

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

[22] EB-2009-0084

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.

2.5.1 Capital Structure

The elements of the deemed capital structure are shown below and must be presented with the required schedules. Appendix 2-OA must be completed for the last OEB-approved and test years. Appendix 2-OB must be completed for all required historical, bridge year and test years, with respect to the following:

- Long-term debt
- Short-term debt
- Preference shares
- Common equity

Explanations are required for material changes in actual capital structure or material differences between actual and deemed capital structure, including:

- Retirements of debt or preference shares and buy-back of common shares
- Short-term debt, long-term debt, preference shares and common share offerings

2.5.2 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 or demand notes or other debt arrangements with affiliates. Note that this is not required for 3rd party debt, e.g. with commercial banks
- 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 or the applicant's proposed approach
- 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 will be affiliated or with a third party, expected term/maturity, any specific capital project(s) that the debt funding is for, etc.)
- If the applicant is proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions
- Historic Return on Equity achieved

Notional debt is that portion of the deemed debt capitalization that results from differences between the distributor's actual debt and the deemed debt thickness of 60% (56% long-term debt and 4% short-term debt).

2.5.3 Not-for-Profit Corporations

In prior decisions, the OEB determined that applicants which are not-for-profit corporations may apply using the OEB's deemed capital structure and cost of capital.

A distributor that is a not-for-profit corporation must document and provide the following as part of its application:

- The requested capital structure
- The requested cost of capital (including the proposed cost of long-term and short-term debt and the proposed return on equity)
- A statement as to whether the revenues derived from the return on equity component of the cost of capital will be used to fund reserves (operating, capital, insurance, etc.) or will be used for other purposes
- If the revenues derived from the return on equity component of the cost of capital will be used to fund reserves, provide the specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied.
- If the revenues derived from the return on equity component of the cost of capital will be used for other purposes, provide a statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities). Provide rationale supporting the use of the revenues in this manner. Also provide the governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities.

If the applicant has approved reserves from previous OEB decisions, the applicant must also document the following:

- The limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits.
- The current balances of any established capital and/or operating reserves.

2.6 Exhibit 6: Revenue Requirement and Revenue Deficiency or Sufficiency

The applicant must include the following information in this exhibit (provide cross reference to where in the application further details can be found for each item), 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
- Gross Deficiency or Sufficiency in Revenue

The filing requirements have been designed in a manner to keep 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 Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) 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 filed in the application must be provided so that parties can easily map the summary cost driver information in this exhibit to the evidence elsewhere in the application that supports it.

The applicant must provide the impacts of any change in methodologies (e.g. accounting standards or policies) on the overall deficiency/sufficiency and on the individual cost drivers contributing to it.

2.6.1 Revenue Requirement Work Form

The RRWF is a live Excel spreadsheet issued by the OEB along with these filing requirements that provides a high-level summary of the numbers in the application.

The RRWF also serves as a summary of the changes to the proposed revenue requirement through the stages of application processing. Applicants should also be mindful that the “Summary of Proposed Changes” (Tab 14: Tracking Form), summarizing cumulative changes to key results of the application is required. This tab must be completed and kept updated during the course of the application review process.

Beginning with 2017, the RRWF was expanded to include summaries of customer/connection and load forecast, cost allocation, rate design and revenue reconciliation data. These changes allow for the RRWF to calculate and present a summary of the proposed distribution rates, excluding any rate riders or rate adders. This has enabled elimination of some of the appendices, such as 2-P and 2-V, which are replaced by tabs in the RRWF. The RRWF thus serves as a cost of service rate generation model. However, it does not have the level of detail in models used by distributors in supporting their applications, and is not intended to replace them. It does serve as a summary used to check the proposed revenue requirement and the rates to recover it through the application process. If the enhanced RRWF cannot reflect a distributor’s proposed rates accurately, the distributor must file its rate generator model.

Applicants should refer to the final RRWF reflecting the OEB's Decision and Rate Order in their last cost of service application for OEB-approved numbers to be used in various Appendices and schedules as required and discussed elsewhere in Chapter 2 (e.g. Appendices 2-JA, 2-JB, 2-JC).

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 reconcile with the appropriate numbers in other exhibits.

The applicant must provide the following analyses for revenues:

- Calculation of bridge year forecast of revenues at existing rates
- Calculation of test year forecasted revenues at each of:
  - Existing rates
  - Proposed rates[23]

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

Applicants must make use of the stand-alone principle when determining these amounts.[24] Applicants are expected to exercise sound tax planning and are expected, for rate-setting purposes, to maximize tax credits and take the maximum deductions allowed.

2.6.2.1 Income Taxes or PILs

The applicant must provide the following information:

- Detailed calculations of income tax or PILs, as applicable. These calculations must include a completed live Excel version of the Income Tax /PILs model available on the OEB's website, including derivation of adjustments (e.g. tax credits, CCA adjustments) for the historical, bridge and test years. Regulatory assets and liabilities must be excluded from taxes/PILs calculations both when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts.
- Supporting schedules and calculations identifying reconciling items
- Copies of the most recent Federal and Provincial tax returns. Non-utility tax items, if material, must be separated. This is to be done in the PILs model.
- Financial statements included with tax returns, if different from the financial statements filed in support of the application (see section 2.1.8)
- A calculation of tax credits (e.g. Apprenticeship Training Tax Credits, education tax credits, Ontario Regional Opportunities Investment Tax Credits). A Scientific Research and Experimental Development return, if filed, may have confidential

[23] Test year revenues at existing rates and at proposed rates are carried forward and used in Exhibit 6 (Revenue Requirement and Revenue Sufficiency/Deficiency), Exhibit 8 (Rate Design) and in the RRWF.
[24] Please see the Introduction (page 2) of this document.

personal information (e.g. Social Insurance Number, address, hourly rate, etc.) of the people who are apprenticing; all such personal confidential information must be either removed or redacted from the filing, and the unredacted version need not be filed.

- Supporting schedules, calculations and explanations for “other additions” and “other deductions” for determining taxable income in the applicant’s PILs model
- Completion of the integrity checks in the PILs model

Accelerated CCA

On June 21, 2019, Bill C-97, the *Budget Implementation Act, 2019, No. 1,* was given Royal Assent. Included in Bill C-97 are various changes to the federal income tax regime. One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive program, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018.

As per the OEB’s July 25, 2019 letter, the OEB expects distributors to:[25]

1. Record the impacts of CCA rule changes in Account 1592 - PILs and Tax Variances – CCA Changes[26] for the period November 21, 2018 until the effective date of the distributor’s next cost-based rate order.[27]
2. Record the full revenue requirement impact of any changes in CCA rules that are not reflected in base rates[28] in Account 1592 – PILs and Tax Variances – CCA Changes.
3. Bring forward any amounts tracked in Account 1592 - PILs and Tax Variances – CCA Changes for review and disposition in accordance with the OEB’s filing requirements for the disposition of deferral and variance accounts, which would generally coincide with a distributor’s next cost-based rate application.[29]

Accordingly, distributors must provide the following information:

- The full revenue requirement impact recorded in Account 1592 - PILs and Tax Variances – CCA Changes and the balance sought for review and disposition
- The method used in calculating the full revenue requirement impact recorded in Account 1592

[25] *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, July 25, 2019
[26] The OEB has established this sub-account of Account 1592 specifically for the purposes of tracking the impact of changes in CCA rules.
[27] This impact includes Bill C-97 CCA rule changes as well as any future CCA changes instituted by relevant regulatory or taxation bodies.
[28] The OEB noted that these impacts should be recorded as of the effective date of the changes in CCA rules, which for the Bill C-97 changes is November 21, 2018.
[29] The OEB expected that distributors will combine the impacts associated with the 2018 stub period with future years when disposing of the CCA-related sub-account.

- Detailed calculations by year for the full revenue requirement impact recorded in Account 1592

The OEB's long-standing practice with respect to the impact of changes in taxes due to regulatory or legislated tax changes during an incentive rate-setting period has been to share the impacts between distributor shareholders and ratepayers on a 50/50 basis.[30]

However, distributors should not expect that this practice will necessarily apply in respect of CCA rule changes, and determinations as to the appropriate disposition methodology will be made at the time of each distributor's cost-based application.

The OEB also recognizes that there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. Applicants may propose a mechanism to smooth the tax impacts over the five year IRM term. The OEB will assess applicants' smoothing proposals on a case by case basis. If the OEB is satisfied with the smoothing proposals, applicants may not be required to continue to use the Account 1592 sub-account for CCA changes going forward.

2.6.2.2 Other Taxes

Taxes other than income taxes or PILs, as defined in the APH (e.g. property taxes), should only be included in Account 6105, effective January 1, 2012. Account 6105 is not an OM&A account and should therefore be excluded from all OM&A totals. The applicant should provide an explanation of how these tax amounts are derived.

2.6.2.3 Non-recoverable and Disallowed Expenses

Where an expense incurred by a distributor is non-recoverable in the revenue requirement (e.g. certain charitable and political donations as discussed in section 2.4.3.7 above) or is disallowed for regulatory purposes, such a cost should also be excluded from the regulatory tax calculation.

2.6.3 Other Revenue

The following information on each of the other distribution revenue accounts must be provided and Appendix 2-H completed:

- 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
- Revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (including any

[30] EB-2007-0673: Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, Section 3 - Tax Changes in Relation to the Z-factor, p.35.

credits to be provided to customers, e.g. for paperless billing) (Note that the derivation of proposed charges should be discussed in Exhibit 2.8.5).

- Any revenue from affiliate transactions, shared services, or corporate cost allocations as described in section 2.4.3.2. 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 (see Appendix 2-N for the required format)
- Accounts related to affiliate revenue and affiliate expense are shown in the footnote of Appendix 2-H
- Revenue from affiliate transactions should be recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations
- Expenses from affiliate transactions should be recorded in Account 4380, Expenses of Non Rate-Regulated Utility Operations

A distributor should refer to Article 220 - Uniform System of Accounts and Article 340 - Allocation of Costs and Transfer Pricing of the APH for more detailed accounting guidance.

Appendix 2-H – Other Operating Revenue, indicates that each account must be broken down in more detail, showing the components of each account.

The balances recorded in Account 4375, Revenues from Non Rate-Regulated Utility Operations, and Account 4380, Expenses of Non Rate-Regulated Utility Operations, must reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Cost Allocation for the three historic years, the bridge year and the test year. Any differences must be reconciled.

Any revenue related to microFIT charges must be recorded as a revenue offset in Account 4235 – Miscellaneous Service Revenue and not be included as part of the base distribution revenue requirement.

As outlined in section 2.4.3.2 – Shared Services and Corporate Cost Allocation, costs that are included in an distributor's OM&A must be excluded from the account balances incorporated into Appendix 2-H – Other Operating Revenue (i.e. excluded as offsets to the revenue requirement) and vice versa. Costs that are included in a distributor's OM&A must also be excluded from Appendix 2-N – Shared Services and Corporate Cost Allocation.

The distributor must ensure that its transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business, products or services.

The distributor must ensure compliance with Article 340 of the APH and provide explanations for any deviations if applicable.

Distributors must identify any discrete customer groups that may be materially impacted by changes to other rates and charges.

Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenues.

2.7 Exhibit 7: Cost Allocation

This exhibit includes information on cost allocation study requirements, class revenue requirements and revenue-to-cost ratios.

2.7.1 Cost Allocation Study Requirements

The OEB outlined its cost allocation policies in the OEB's reports of November 28, 2007 Report of the Board on Application of Cost Allocation for Electricity Distributors[31] and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy[32] (the Cost Allocation Reports).

A completed cost allocation study using the OEB-approved methodology, or the distributor's study and model must be filed. This filing must reflect the forecasted test year loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The most current update of the model is available on the OEB's website. Sheets 11 and 13 of the RRWF[33] must also be completed.

In previous decisions, the OEB has required that load profiles for all classes be updated at the same time, not just selective updating.[34] Distributors should make best efforts to update all classes' load profiles using the most recent available data, particularly from smart, MIST and interval meters, net metered loads, class A loads, sites with self supply infrastructure.

If a distributor is not able to update its load profiles at this time, an explanation should be provided and the distributor should confirm that it intends to put plans in place to update its load profiles the next time a cost allocation model is filed. In such cases, the load profiles provided by Hydro One for use in the original Informational Filing may be used, scaled to match the load forecast as it relates to the respective rate classes (see section 2.3.2 above). This will be necessary, in particular, if a rate class has experienced a decline in customers or has disappeared, or is forecasted to disappear in the test year. The cost allocation model must be consistent with the test year load forecast. In the case where a new customer class is being created, the applicant must explain the basis for the

[31] EB-2007-0667

[32] EB-2010-0219

[33] Sheet 11 is "Cost Allocation and Rate Design" and Sheet 13 is "Rate Design and Revenue Reconciliation" These replace the former Appendix 2-P and 2-PA.

[34] EB-2014-0002, Horizon Utilities Corporation, Decision and Order, December 11, 2014, p.6

class load the class load profile, and ensure consistency with the load forecast information as per section 2.3.2.

The distributor must provide a spreadsheet and a description with example calculations to show how the demand data in the cost allocation model was derived from the load forecast and load profiles.

Distributors should refer to section 2.6.4 of the March 31, 2011 Cost Allocation Report concerning weighting factors for allocation of certain costs. Distributors are expected to develop their own weighting factors, and a description of the weighting factors is required. Worksheet I5.2 Weighting Factors includes a calculator for the billing and collecting weighting factor to assist distributors. Since this is used to derive an allocator, not to directly calculate the allocation of costs, this may be completed on a forecast basis. If the billing and collecting methodology used in a recent historic year is expected to continue into the test year, it may also be completed on a historic basis. As explained in the March 31, 2011 report, if the distributor has chosen to use the default weighting factors, an explanation for this choice must be provided. A distributor can choose to use the same weightings from its previous Cost of Service application on the condition these were accepted by the OEB and there have been no significant changes in the distributor's policies or practices that would impact the weightings. If this approach is used, then the distributor must make reference to the previous application.

A complete hard copy of the cost allocation model is not required, but the distributor must file a complete live Excel cost allocation model, whether using the OEB-issued one or a different model, with the application. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.

2.7.1.1 Specific Customer Class(es)

The following sections provide policy guidance on cost allocation matters for specific customer classes.

Large General Service and Large Use Classes

As a reminder, the treatment of the Transformer Ownership Allowance has been revised in the current version of the cost allocation model, as compared to the version that the distributor may have used in a previous rebasing application.

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(s) support(s) the host distributor's approach to the allocation of costs to the embedded distributor(s). If the host distributor 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 the RRWF.

- If the host distributor proposes to establish a new embedded distributor class, the host distributor must include that class in its cost allocation study and in the RRWF and provide rationale and supporting evidence for the establishment of an Embedded Distributor class, as applicable. The host distributor must provide the costs of serving the embedded distributor(s), load served, information regarding ownership of relevant assets involved in the connection(s), whether assets are dedicated to the embedded distributor(s) or shared to serve other customers, 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 the RRWF. 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 distributor(s), 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 rates for the general service class for recovering the costs of providing low voltage distribution services to the embedded distributor(s).

Unmetered Loads (Including Street Lighting)

For allocation of costs related to unmetered loads, distributors should refer to the OEB's Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads, which amended section 2.4.6 of the DSC, and the OEB's letter of June 12, 2015, which outlined a new cost allocation policy for the street lighting rate class. A new "street lighting adjustment factor" will be used to allocate costs to the street lighting rate class for primary and line transformer assets. The "street lighting adjustment factor" replaces the "number of connections" allocator. The cost allocation model has been updated to reflect the street lighting adjustment factor.

MicroFIT class

The OEB does not expect a distributor to include microFIT as a separate class in the cost allocation model beginning in 2017. The OEB establishes a generic rate which can be adopted. The OEB has reviewed the generic rate for the 2021 rate year and the microFit rate will be maintained at the current rate of $4.55.[35] If a distributor believes that it has unique circumstances which would justify a different rate it must file appropriate documentation to support such a rate.

Standby Rates

A standby rate is charged by a distributor to a customer with load displacement facilities behind its meter to compensate the distributor for the cost of maintaining the ability to accommodate the total load of the customer at any time. The charge must not inadvertently subsidize other customers or unduly burden the load displacement customer.

Standby rates have been approved on an interim basis since 2006 for some distributors. Distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal.

A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).

2.7.1.2 New Customer Class(es)

If the distributor is establishing a new customer class or changing the definition(s) of existing customer classes, the rationale for doing so is required. Information provided in the distributor's previous cost of service application concerning class revenue requirements must be restated in the RRWF on the basis of the proposed customer classes to provide continuity with the proposed customer classes in the current application.

2.7.1.3 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 provide continuity of information, the distributor must restate information from its previous cost of service application concerning class revenue requirements in the RRWF on the basis of the proposed customer classes, where possible.

2.7.2 Class Revenue Requirements

The RRWF shows the format for filing cost allocation information in Sheet 11: Cost Allocation and Rate Design and includes four tables. The first table is the format for showing the test year class revenue requirements, which are produced in output sheet O-

[35] Review of Fixed Monthly Charge for microFIT Generator Service Classification - OEB File Numbers EB-2009-0326 and EB-2010-0219, February 25, 2021

1 of the OEB model. This table also includes a comparison to the most recent study previously filed with the OEB.

Rate rebalancing is the process of adjusting rates for different customer rate classes in order to ensure that the revenues collected from each class reasonably reflect the costs to service customers in each class while ensuring the distributor recovers its overall revenue requirement. To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply 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 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.

2.7.3 Revenue-to-Cost Ratios

The OEB has established ranges for revenue-to-cost ratios. The range of acceptable ratios is in section 2.9.4 of the March 31, 2011 Cost Allocation Report.

As per the OEB's letter of June 12, 2015, the OEB has narrowed the revenue-to-cost ratio policy range for the street lighting rate class from 70-120% to 80-120% consistent with views expressed in the December 19, 2013 Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads.

The third table on sheet 11 of the RRWF 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, and expressed as ratios with the class revenue requirements derived in the updated cost allocation model
- The ratios that are proposed for the test year

Results flowing from the updated cost allocation model may show some ratios being outside of the OEB-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them within the OEB-approved ranges within a reasonable period of time. Moving revenues closer to costs in one class also means that there will be offsetting adjustments to one or more classes. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant. Applicants are also reminded of the OEB's policy that revenue-to-cost ratios should not be moved away from unity;[36] this may not always be possible when making adjustments overall, but applicants should explain their proposed adjustments and attempt to minimize variances from the OEB's policy.

If the distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided. The fourth table provides a format for presentation of such information. In particular, if the proposed ratios are outside the OEB's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios to within the policy range.

If using a cost allocation model other than the OEB model, the distributor must ensure that costs exclude LV costs and deferral and variance account balances and that revenues exclude rate riders, rate adders and the Smart Metering Entity charge. The distributor must also ensure that information relevant to customer charge unit costs, microFIT unit costs and revenue is consistent with the output from the OEB's model.

2.8 Exhibit 8: Rate Design

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 and appropriate.

2.8.1 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
- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study

Calculations of fixed/variable proportions should use the billing determinants from the proposed load forecast as the basis of the calculation, unless a different billing determinant is used, e.g. for streetlighting, sentinel lights of unmetered scattered load.

[36] EB-2007-0667, pp. 6-7

If a distributor's current fixed charge for any non-residential class is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling for any non-residential class.

The fixed/variable analysis must be net of rate adders, funding adders and rate riders (e.g. LV, smart meter rate riders, DVA disposition).

2.8.2 Retail Transmission Service Rates (RTSRs)

In preparing its application, the distributor must reference the OEB's Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, issued on June 28, 2012, subsequent updates to the UTRs and any host distributor's rates. A completed version of the RTSR model must be filed in live Excel format.

The distributor must ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation per section 2.2.5, as it relates to rates such as RTSRs, or provide explanations for any differences.

2.8.3 Retail Service Charges

Retail services refer to services provided by a distributor to retailers or customers related to the competitive supply of 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. Applicants should refer to the most recent rate order for the current approved rates.

On November 29, 2018, the OEB issued its Report of the Ontario Energy Board: Energy Retailer Service Charges, which sets out the OEB's conclusions following the review of energy retailer service charges. The final charges and accounting guidance were set out in a Decision and Order, to be effective May 1, 2019.[37] Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) or Retail Service Charges Incremental Revenue sub-account are to dispose of the balances and the OEB will eliminate the sub-accounts. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement.

2.8.4 Regulatory Charges

The Wholesale Market Service (WMS) rate is designed to allow distributors to recover costs charged by the IESO for the operation of the IESO-administered markets and the operation of the IESO-controlled grid.

The WMS rate is an energy-based rate (per kWh) applicable to those customers of a distributor who are not wholesale market participants. An embedded distributor who is not

[37] EB-2015-0304, Decision and Order, February 14, 2019

a wholesale market participant would be treated as a customer to the host distributor and would be charged the WMS rate.

The Rural or Remote Electricity Rate Protection (RRRP) program is designed to reduce costs for eligible customers located in certain rural or remote areas where the cost of distributing electricity is higher.

The Standard Supply Service Charge is set by the OEB as an administrative fee payable by customers who purchase electricity directly from their distributor.

These rates are set by the OEB on a generic (i.e. province-wide) basis. Applicants should refer to the most recent rate order for the current approved rate. Distributors wishing to apply for a rate other than the generic rate set by the OEB must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate.

2.8.5 Specific Service Charges

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 new or revised charge. Distributors must separately identify in the Application Summary all proposed changes in the application that will have an impact on customers, including any changes to other rates and charges that may affect discrete customer groups. Applicants must also identify the specific customers or customer groups that will be impacted by each such proposal.

The calculation of the charges must include the following elements:

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

Distributors must also identify any rates and charges that are included in their Conditions of Service but do not appear on the OEB-approved tariff sheet, and provide an explanation for the nature of the costs being recovered. A schedule outlining the revenues or capital contributions recovered from these rates and charges from the last OEB-approved year (both what was approved and the actual for that year) to 2020 and the revenue or capital contributions forecasted for the 2022 bridge and 2023 test years must also be provided, as well as a proposal and explanation as to whether these rates and charges should 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).

Wireline Pole Attachment Charge[38]

The wireline pole attachment charge is being updated, and the new version will be effective for applications for 2023 rates.

On March 22, 2018, the OEB issued its [Report on Wireline Pole Attachment Charges](),[39] updating its approach to wireline pole attachments. The OEB determined that it was in the public interest to set a province-wide wireline pole attachment charge of $43.63 per pole per year for each user effective January 1, 2019. This new charge applies to all licensed distributors that have not received OEB approval for a distributor-specific pole attachment charge, and is adjusted annually based on the OEB's inflation factor.

As a result of the inflationary adjustment for January 1, 2020, the charge was revised to $44.50. On December 10, 2020, the OEB issued an Order[40] which determined that the inflationary adjustment for 2021 would be suspended. The Order stated that the province-wide pole attachment charge of $44.50 will remain in effect as of January 1, 2021 on an interim basis, until further notice. The Order does not affect any distributor that has an approved distributor-specific wireline pole attachment charge.

In a [letter]() issued March 22, 2018, the OEB instructed distributors to record the excess incremental revenue as of September 1, 2018 until the effective date of its rebased rates in a new variance account related to pole attachment charges. Distributors will need to refund the closing balance in the distributor's next cost of service application. Distributors may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount and closing the account.

2.8.6 Low Voltage Service Rates (where applicable)

If the distributor is (fully or partially) embedded, the distributor must provide the following information:

- Forecast of LV costs, which is the sum of the host distributors' 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

[38] The Wireline Pole Attachment Charge is currently under review.
[39] EB-2015-0304, March 22, 2018
[40] EB-2020-0288, Order, Wireline Pole Attachment Charge, December 10, 2020

- Support for the forecast of LV costs: forecast volumes and actual or forecasted host distributor(s) LV rates. For example, a 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 forecasted LV costs to customer classes (generally in proportion to transmission connection rate revenues)
- Proposed LV rates by customer class to reflect these costs

2.8.7 Smart Meter Entity Charge

On March 1, 2018, the OEB approved the application by the IESO, in its capacity as the Smart Metering Entity (SME), for a smart metering charge (SMC) for the 2018-2022 period. The OEB also issued a letter to all licensed electricity distributors outlining that the SMC is a pass through amount to be charged by distributors to all applicable customers in the Residential and General Service <50kW classes. The retail level charge appears as the Smart Metering Entity Charge on a distributor's tariff of rates and charges.

On March 23, 2018, the OEB issued updated guidance on the Smart Metering Entity Charge. Distributors must follow the accounting guidance provided in the OEB letter.[41]

2.8.8 Loss Adjustment Factors

The distributor must document 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, including whether it is fully or partially embedded
- Details of loss studies and recommendations, if required by a previous OEB decision
- Calculations showing the losses in previous years. A minimum of three years of historical data is required, although five years of historical data is preferred.
- A completed Appendix 2-R showing the energy delivered to the distributor with and without losses
- If the proposed distribution loss factor is greater than 5%, an explanation for the level of the loss factor, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward
- Explanation of the derivation of the SFLF, including reasons for any differences from the standard SFLFs referenced in Appendix 2-R, Row H

[41] OEB Letter *Updated Guidance on Smart Metering Entity Charge*, March 23, 2018

- Reconcilliation between the application and the Electricity Reporting and Record-keeping Requirement (RRR) filing

2.8.9 Tariff of Rates and Charges

The distributor must provide the current and proposed tariff of rates and charges. Distributors must ensure that each proposed change is explained and supported in the appropriate section of the application. Distributors must file Bill Impacts model. The tariff sheets, which are produced by the Tariff Schedule and the Bill Impacts model in a separate file, must be filed in excel and PDF format.

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 and charges on the Tariff of Rates and Charges to be approved by the OEB. Proposed tariffs must include the applicable regulatory charges (i.e. WMS, Rural or Remote Electricity Rate Protection, and Standard Supply Service Administration charge), and any other generic rates such as the current SMC, as ordered by the OEB.

2.8.10 Revenue Reconciliation

With the proposed Tariff of Rates and Charges, the following information must be provided:

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

A table that reconciles the base revenue requirement against the revenues recovered through the proposed rates must be provided in Sheet 13 of the RRWF. The purpose of the revenue reconciliation is to check that the test year demand and the proposed rates recover the base revenue requirement to serve the forecasted customers and demand/consumption, subject to rounding.

2.8.11 Bill Impact Information

This information must be filed for all customer classes in the Tariff Schedule and Bill Impacts model which identifies existing rates and proposed changes to rates, and calculates detailed bill impacts (including % change in distribution excluding pass-through costs (e.g. DVAs) – “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.

Rates and charges input into the Tariff Schedule and Bill Impacts model should be rounded to the decimal places as shown on the existing and proposed Tariff of Rates and Charges.

On April 14, 2016, the OEB issued the report Defining Ontario's Typical Electricity Customer in which it determined that the typical residential consumption that will be used for illustrative purposes should now be 750 kWh per month.

Bill impacts must be provided for a residential customer consuming 750 kWh per month, a residential customer consuming at the lowest 10th percentile of consumption (as described in 2.8.13), and a general service customer consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide bill impacts for a range of consumption levels that are relevant to their service territory for each customer class. A general guideline of consumption levels is provided in the Tariff Schedule and Bill Impacts model.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical impact for such customer(s), and provide an explanation.

2.8.12 Rate Mitigation

A distributor is expected to review bill impacts to determine if measures should be implemented to smooth impacts resulting from the application.

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:

- Identification of all customer classes or groups of customers that would experience 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-class shifts, or longer disposition periods for deferral and variance account balances)
- A justification for all mitigation measures proposed, including reasons if no mitigation is proposed
- Any other information the distributor believes is relevant to its mitigation proposal

The distributor must ensure that the populated Tariff Schedule and Bill Impacts model reflects any mitigation plan proposed in the application.

2.9 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 DVAs in this application:

- Provide a table showing all DVA accounts that have not been disposed of yet, showing principle balance, interest or carrying charges, and total balance for each account and whether the account is being proposed for disposition
- If applicable, the applicant must provide a brief description of any account that the applicant may have used differently than as described in the APH, the relevant accounting order or another OEB document.
- A continuity schedule for the period from the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding DVAs. A completed version of the DVA Continuity Schedule, must be filed in live Excel format.
    - The opening principal amounts as well as the opening interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable[42] approved closing balances.
- Interest rates applied to calculate the carrying charges for each regulatory DVA. The distributor must confirm that it has used the rates established by the OEB by month or by quarter for each year. The rates that should be used are provided on the OEB's website. The most recently posted interest rate should be used for any future periods.
- Explanation if the account balances in the continuity schedule differ from the account balances in the trial balance reported through the Electricity RRR and documented in the distributor's audited financial statements. This should be included in the tab Appendix A of the DVA Continuity Schedule.
    - This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the Electricity RRR is to be provided in the continuity schedule.
- Identification of which Group 2 accounts the distributor proposes be continued and which, if any, it proposes be discontinued on a going-forward basis, with an explanation for these proposals
- Identification of any new accounts or sub-accounts that the applicant is requesting, and justification for each requested account or sub-account (see section 2.9.2). This must correspond with information provided in Exhibit 1 (see section 2.1.3).
- A statement as to whether or not the applicant has made any adjustments to DVA balances that were previously approved by the OEB on a final basis. The OEB

[42] The last approved closing balances for Group 1 and Group, 2 accounts may be for different year-ends. Also, if Group 1 balances were last approved on an interim basis and adjustments have been made to the approved balances, a distributor needs to complete the continuity schedule starting from the last balances approved on a final basis.

expects that no adjustments are made to any DVA balances previously approved by the OEB on a final basis.

    - On October 31, 2019, the OEB issued a letter to all electricity distributors discussing its approach to address accounting or other errors, in respect of Group 1 DVAs that have previously been disposed of by the OEB on a final basis. When an accounting or other error is discovered after the balance in one of the Group 1 DVAs has been cleared by a final order of the OEB, the applicant should refer to the October 31, 2019 letter mentioned above for guidance. The OEB expects distributors to disclose errors that have been discovered in their accounting records as part of their rate applications and to record correcting adjustments to the affected account(s) in the year in which the error is discovered. If adjustments have taken place, distributors must provide explanations for the nature and the amounts of adjustments, and include appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts".

- All distributors are required to complete and submit the GA Analysis Workform for each year that has not previously been approved by the OEB for disposition irrespective of whether they are seeking disposition of the Account 1589 – RSVA GA balance as part of their current application. If the distributor is adjusting the Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform is required to be completed from the year after the distributor last received final disposition for Account 1589.
- A statement confirming that the distributor has complied with the OEB's February 21, 2019 guidance on the accounting for Accounts 1588 – RSVA Power and 1589 – RSVA Global Adjustment.[43]

2.9.1 Disposition of Deferral and Variance Accounts

The distributor must:

- For any accounts identified in the summary table as not being proposed for disposition, explain the reasons why
- Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the most recent audited financial statements or provide explanations for any variances
    - If the RRR balances do not agree to the year-end balances in the DVA Continuity Schedule, a distributor must reconcile and explain the difference(s).
- For any utility-specific accounts requested for disposition (e.g. Account 1508 sub-accounts), provide supporting evidence showing how the annual balance is derived and provide the relevant accounting order.

[43] The OEB expects that effective January 1, 2019, all balances recorded to accounts 1588 and 1589 have been recorded in accordance with the OEB's February 21, 2019 accounting guidance.

- Request final disposition of residual balances for vintage Account 1595 sub-accounts once, normally in the fourth rate year after the year the rate rider expires. A completed 1595 Analysis Workform for residual balances that meet the eligibility requirements for dispositions of Account 1595 Sub-accounts must be filed (see section 2.9.1.4).
- If a distributor is proposing to allocate a DVA for which the OEB has not established an approved allocator, the distributor must propose an allocator based on the cost driver(s), with justification.
    - Indicate the proposed billing determinants, including a charge type (fixed or variable) for recovery purposes, and include this in the continuity schedule.
- Propose rate riders that dispose of the balances. The default disposition period is one year; if the applicant is proposing an alternative recovery period, an explanation must be provided.
    - The DVA Continuity Schedule should calculate the DVA disposition rate riders using the load data included in the load forecast section of the application.
    - Volumetric rate riders are calculated at four decimal places. Rate riders of $0.0000 must not be included on the tariff sheet. The entire OEB-approved amount for recovery or refund will typically be recorded in a USoA account to be determined by the OEB for disposition in a future rate-setting application.
- The DVA Continuity Schedule establishes separate rate riders to recover the balances in the RSVAs from wholesale market participant (WMP) customers. A WMP refers to any entity that participates directly in any of the IESO-administered markets and that settles commodity and market-related charges with the IESO even if they are embedded in the distributor's distribution system. Accordingly, a distributor must not allocate any balances to WMP customers from Account 1580 RSVA – Wholesale Market Services Charge, Account 1580 Variance WMS, Sub-Account CBR Class B, Account 1588 RSVA – Power, and Account 1589 RSVA – Global Adjustment. A distributor must also ensure that rate riders are calculated appropriately for WMP customers for Account 1584 RSVA – Retail Transmission Network Charge, Account 1586 RSVA – Retail Transmission Connection Charge and Account 1595 – Disposition/Refund of Regulatory Balances. The DVA Continuity Schedule model allocates these balances accordingly.
- Propose disposition of Account 1592 – PILs and Tax Variances, Sub-account CCA Changes. Refer to section 2.6.2.1 for further details. The applicant must also provide the following:
    - Calculations for accelerated CCA differences per year, based on both actual capital additions and the capital additions used in the PILs/tax section in the applicant's last cost-based rates proceeding. These calculations should include:
        - The undepreciated capital cost (UCC) continuity schedules for each year, itemized by CCA class

    - The calculated PILs/tax differences
    - The grossed-up PILs/tax differences
    - Any other applicable information
  - A reconciliation of these amounts to the amounts presented in the Account 1592 sub-account for CCA changes in the DVA continuity schdedule

2.9.1.1 Disposition of Global Adjustment Variance

Class B and Class A Customers

Most customers pay the GA charge based on the amount of electricity they consume in a month (kWh). These customers are referred to as Class B. Customers who participate in the Industrial Conservation Initiative (ICI), referred to as Class A, pay GA based on their percentage contribution to the top five peak Ontario demand hours (i.e. peak demand factor) over a year-long period.[44] Distributors that settle GA costs with Class A customers based on actual GA prices should allocate no GA variance balance to these customers for the period that customers were designated as Class A.

For Class B non-RPP customers, the GA variance account (i.e. Account 1589 – RSVA Global Adjustment) captures the difference between the amounts billed (or accrued billings) to non-RPP customers by the distributor and the actual amount paid by the distributor to the IESO (or host distributor) for those customers.

When disposing of the balances recorded in the GA variance account, distributors must establish a separate rate rider that will be included in the delivery component of the bill that would apply prospectively to non-RPP Class B customers. The billing determinants and all the rate riders for the GA are calculated on an energy basis (kWh) regardless of the billing determinants used for distribution rates for the particular class. The DVA Continuity Schedule will calculate the GA rate riders on an energy basis (i.e. kWh).

The DVA Continuity Schedule will also allocate the portion of Account 1589 to customers who transitioned between Class A and Class B, during the period in which the balance requested for disposition has accumulated, based on customer-specific consumption levels. Each transitioning customer will only be responsible for the customer-specific amount allocated to them and are not to be charged/refunded the general GA rate rider associated with these balances. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transitioned between Class A and Class B during the disposition period.

[44] Refer to the IESO's site for details on Class A eligibility under the Industrial Conservation Initiative.

GA Analysis Workform

All distributors are required to complete the GA Analysis Workform for each year that has not previously been approved by the OEB for disposition. If the distributor is adjusting the Account 1589 balance that was previously approved on an interim basis, the GA Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589. The GA Analysis Workform helps the OEB assess if the annual variance that is recorded in Account 1589 is reasonable. The GA Analysis Workform compares the actual general ledger transactions recorded during the year to an expected principal balance that is calculated based on monthly GA volumes, revenues and costs.

As described at Note 5 in the GA Analysis Workform, distributors are required to reconcile any discrepancy between the actual and expected balance by quantifying differences (e.g., true-ups between estimated and actual costs and/or revenues). Any remaining, unexplained discrepancy will be assessed for materiality and could prompt further analysis before disposition of the balance is approved. Any unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation. To further support a conclusion that GA charges have been appropriately allocated between customer classes, distributors must also perform a reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.

The GA Analysis Workform is available on the OEB's website and is to be filed in live Excel format. See the GA Analysis Workform Instructions for detailed instructions on how to complete the Workform, as well as any new changes to the Workform.

2.9.1.2 Commodity Accounts 1588 and 1589

On February 21, 2019, the OEB issued a letter titled *Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment* as well as the related accounting guidance (Accounting Guidance).[45] This Accounting Guidance is effective January 1, 2019 and was to be implemented by August 31, 2019. The OEB expects that all transactions recorded to these accounts during 2019 and each year thereafter, will have been accounted for in accordance with this guidance. If a distributor has not implemented the Accounting Guidance, it must indicate this. Distributors should indicate the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, distributors should indicate the year in which balances were last disposed on a final basis.

[45] *Accounting Procedures Handbook Update – Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589,* February 21, 2019.

Final Disposition Requests after Implementation of Accounting Guidance

A distributor that is requesting final disposition of balances for the first time following implementation of the Accounting Guidance must confirm that it has fully implemented the the Accounting Guidance effective from January 1, 2019.

Distributors are also expected to consider this Accounting Guidance in the context of pre-2019 balances that have yet to be disposed of on a final basis. To request final disposition of these balances as part of an application, distributors must confirm that these historical balances have been considered in the context of the Accounting Guidance and provide a summary of the review performed. Distributors must also discuss the results of the review, whether any systemic issues were noted, and whether any material adjustments to those balances have been recorded. A summary and description of each adjustment made to the balances must be provided in the application.

The expectations of final disposition requests of Account 1588 and Account 1589 balances are as follows:

1. Interim disposition of historical balances or no disposition requested

   Some distributors may have received approval for interim disposition of historical account balances, or did not request disposition of account balances in a prior rate application prior to implementation of the Accounting Guidance. If these distributors have now reviewed these balances in the context of the Accounting Guidance and are confident that there are no systemic issues with their RPP settlement and related accounting processes, such distributors may explain those circumstances and request final disposition of these balances. However, if the distributor identified errors or discrepancies that materially affect the ending account balances, the distributor should adjust their account balances prior to requesting final disposition.

2. No disposition of historical balances and concerns noted

   Distributors that did not receive approval for disposition of historical account balances due to concerns noted by the OEB should apply the Accounting Guidance to those balances and adjust the balances as necessary, prior to requesting final disposition.

   If a distributor has yet to fully implement the Accounting Guidance effective from January 1, 2019, the distributor must provide explanation as to why this guidance has not been implemented, the status of the implementation process, and the expected implementation date.

Certification of Evidence

The OEB requires a certification of evidence by the Chief Executive Officer, or Chief Financial Officer, or equivalent. The application must include a certification that the distributor has processes and internal controls in place for the preparation, review, verification and oversight of the account balances being disposed.

2.9.1.3 Disposition of CBR Class B Variance

Distributors must propose disposition of Account 1580 sub-account CBR Class B in accordance with the Capacity Based Recovery (CBR) Accounting Guidance. The balance in sub-account CBR Class B must be disposed over the default period of one year.

In the DVA Continuity Schedule, a distributor must indicate whether they served any Class A customers during the period where the Account 1580 CBR Class B sub-account balance accumulated. If so, a separate rate rider will be calculated in Tab CBR B of the DVA Continuity Schedule. However, if the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be transferred to Account 1580 – WMS control account and the balance will be disposed through the general-purpose Group 1 DVA rate riders.[46] If the distributor did not have any Class A customers during the period in which the Account 1580 CBR Class B sub-account balance accumulated, the DVA Continuity Schedule will transfer the sub-account balance to the Account 1580 – WMS control account and include the CBR amounts as part of the general purpose Group 1 DVA rate riders.

For the disposition of Account 1580, sub-account CBR Class A, distributors must follow the OEB's CBR accounting guidance, which results in balances disposed outside of a rate proceeding.

The DVA Continuity Schedule will allocate the portion of Account 1580 sub-account CBR Class B to customers who transitioned between Class A and Class B, during the period in which the balance requested for disposition has accumulated, based on customer-specific consumption levels. Each transitioning customer will only be responsible for the customer-specific amount allocated to them and will not be charged/refunded the general CBR Class B rider associated with these balances. Customers should be charged in a consistent manner for the entire rate rider period until the sunset date, regardless of whether customers transitioned between Class A and Class B during the disposition period.

[46] This approach is an update to the CBR Accounting Guidance

2.9.1.4 Disposition of Account 1595

When approval for disposition of DVA balances is received from the OEB, the approved amounts of principal and carrying charges are transferred to Account 1595 for that rate year.

Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once and on a final basis. Distributors become eligible to seek disposition of these residual balances two years after the expiry of the rate rider. During the two years after the expiry of the rate rider, distributors may still make billing corrections as per the Retail Settlement Code and are to record the related transactions in the associated Account 1595 sub-account. For example:

- January 1 rate year – If 2019 rate riders end on December 31, 2019, the balance of sub-account 1595 (2019) is eligible to be disposed after the account balance as at December 31, 2021 has been audited. Therefore, sub-account 1595 (2019) would be eligible for disposition in the 2023 rate year.
- May 1 rate year – If 2019 rate riders end on April 30, 2020, the balance of sub-account 1595 (2019) could be disposed when the balance as at December 31, 2022 has been audited. Therefore, sub-account 1595 (2019) would be eligible for disposition in the 2024 rate year.

No further transactions are expected to flow through the Account 1595 sub-accounts once the residual balance has been disposed of.

1595 Analysis Workform

Distributors who meet the eligibility requirements for disposition of residual balances of Account 1595 sub-accounts must file the Account 1595 Analysis Workform. The workform compares principal and interest amounts previously approved for disposition to the residual balances remaining after accounting for the amounts that have been recovered/refunded to customers through rate riders. The workform helps the OEB assess the reasonability of the residual balances in Account 1595 sub-accounts for each vintage year.

Balances in Account 1595 will first be assessed in two groups of accounts; one being the amounts attributable to GA, and the other being the remainder of Group 1 and Group 2 accounts (if applicable). Distributors are expected to provide detailed explanations for any significant residual balances attributable to specific rate riders by customer rate class. Explanations must include for example, volume differences between forecast volumes (used to calculate the rate riders) as compared to actual volumes at which the rate riders were billed. Material residual balances will require further analysis, consisting of separating the components of the residual balances by each applicable rate rider[47] and by customer rate class; a residual balance in either of the two groups of accounts exceeding +/- 10% of the original amounts previously approved for disposition would be considered material. Distributors are required to reconcile the 1595 residual balance with any amounts that have yet to result in associated rate riders (for example, shared tax savings amounts that were previously approved to be transferred to Account 1595 for disposition at a later date).

The 1595 Analysis Workform is available on the OEB's web site and is to be filed in live Excel format.

2.9.1.5 Disposition of Retail Service Charges

If the distributor has a balance 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 balance(s) in Account 1518 and/or Account 1548
- Provide a schedule identifying all revenues and expenses listed by USoA account numbers that are incorporated into the variances recorded in Account 1518 and/or Account 1548
- State whether or not the distributor has followed Article 490, Retail Services and Settlement Variances of the APH for Account 1518 and Account 1548

In the Decision and Order[48] in the matter of energy retailer service charge effective May 1, 2019, the OEB established a variance account for electricity distributors that no longer used the RCVAs. The account captures the incremental revenues resulting from increased service charges authorized while under an approved IRM rate setting plan. The balance in the account is to be refunded to ratepayers in a future rate application, and then the account is to be closed. Distributors may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount and then closing the account.

2.9.2 Establishment of New Deferral and Variance Accounts

In the event a distributor seeks an accounting order to establish a DVA, the applicant must file evidence demonstrating how the following eligibility criteria have been met:

- Causation: the forecasted expense must be clearly outside of the base upon which rates were derived.

[47] Residual account balances will be made up of amounts relating to at least two rate riders, i.e. the GA Rate Rider and the DVA Rate Rider.
[48] EB-2015-0304, dated February 14, 2019

- Materiality: the forecasted amounts must exceed the OEB-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.
- Prudence: the nature of the costs and forecasted quantum must be based on a plan that sets out how the costs will 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 that 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 journal entries, and the manner in which the applicant proposes to dispose of the account at the appropriate time.

2.9.3 Lost Revenue Adjustment Mechanism Variance Account

The LRAMVA is a retrospective adjustment designed to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs. The OEB established Account 1568 as the LRAMVA to capture the difference between the OEB-approved CDM forecast and actual results at the customer rate class level.[49] Treatment of the LRAMVA is documented in the CDM Guidelines.

In July 2016, the OEB developed a generic LRAMVA work form to provide distributors with a consistent approach to calculate LRAMVA. The LRAMVA work form consolidates information that LDCs have received from the IESO.

In December 2016, the OEB indicated in various decisions[50] that changes to an approved LRAMVA amount were not permitted. This policy affects the treatment of verified savings adjustments that may be claimed by distributors. If an LRAMVA amount was approved and disposed, the persistence of the savings adjustment(s) may only be claimed on a "go-forward" basis.[51] LDCs cannot seek recovery of LRAMVA amounts related to savings adjustments for a year in which the corresponding LRAMVA amount has been approved by the OEB on a final basis. For example, if an LDC has received approval of its 2014 LRAMVA balance, excluding 2014 savings adjustments, the LDC must forgo any LRAMVA amounts related to the 2014 savings adjustments as the 2014 LRAMVA balance was approved by the OEB on a final basis.

[49] EB-2012-0003, Guidelines for Electricity Distributor Conservation and Demand Management
[50] EB-2016-0075 (Guelph Hydro 2017 IRM) and EB-2016-0080 (Hydro One Brampton 2017 IRM)
[51] See EB-2016-0214 for an example (North Bay Hydro 2017 IRM)

2.9.3.1 Disposition of the LRAMVA

A new CDM framework has been established by the IESO for the 2021-2024 period. The OEB intends to provide more direction regarding LRAM treatment for savings from the 2021-2024 CDM Framework in a future update to the CDM Guidelines. The update to the CDM Guidelines is currently underway, and the new version will be effective for applications for 2023 rates.

The IESO has made monthly Participation and Cost Reports available to electricity distributors from January 1, 2018 to April 15, 2019. The monthly Participation and Cost Reports include, amongst other information, incremental first year energy savings as well as information related to persistence. Results from the IESO's 2017 program evaluation have been applied to the January 1, 2018 to April 15, 2019 gross unverified savings values, including net-to-gross factors and gross realization rates.

To create the Participation and Cost Reports each distributor submitted detailed project level files to the IESO that contain project level savings and costs (the monthly LDC Report submission). The detailed project level savings files include all relevant information related to each project the distributor has completed and submitted to the IESO.

To calculate net savings values at the project level, distributors should rely on results from the IESO's 2017 program evaluation (e.g., net-to-gross values and gross realization rates).

Distributors should strive to dispose of all CFF-related LRAMVA balances as part of its 2023 rate application. The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available.

Disposition of the LRAMVA

Distributors should use the latest version of the LRAMVA workform when making LRAMVA requests for remaining amounts related to CFF activity. An application for lost revenues should include the following:

- Final Verified Annual Reports if the distributor is claiming lost revenues from savings from CDM programs delivered in 2017 or earlier.
- Participation and Cost Reports and detailed project level savings files made available by the IESO to support the clearance of energy- and/or demand-related LRAMVA balances for the period of January 1, 2018 to April 15, 2019. These reports should be filed in excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017. To support savings claims for CFF projects completed after April 15, 2019, distributors should provide similar supporting evidence.

- Other supporting evidence with an explanation and rationale should be provided to justify the eligibility any other savings from a program delivered by a distributor after April 15, 2019.

In relation to the project level savings reports used to support LRAMVA claims, these documents may contain personal information (e.g., residential customers' names, addresses, postal codes, phone numbers, and email addresses) and/or business information that may be commercially sensitive (e.g., facility consumption information and production information). Personal information and commercially sensitive information is not needed to support LRAMVA claims and should not be filed. Distributors should delete any personal information or commercially sensitive information in the Excel spreadsheets or any other documentation that is filed with the OEB.

In the event that a distributor is of the view that it needs to file the Excel spreadsheets or any other documentation with all of the information included, then the documents must be filed in accordance with the OEB's *Rules of Practice and Procedure* (the Rules). For personal information, the documents must be filed in accordance with Rule 9A of the Rules (and the *Practice Direction on Confidential Filings*, as applicable). For the commercially sensitive information, a distributor should use Rule 10 of the Rules and request confidentiality for the information.

At a minimum, distributors must apply for the clearance of energy and/or demand-related LRAMVA balances attributable to approved energy efficiency programs in a cost of service application.

The distributor shall compare any OEB-approved LRAMVA threshold to actual CDM results at a rate class level. The variances calculated from this comparison shall be recorded in separate sub-accounts for the applicable customer rate classes. Distributors must continue to track the variances between any OEB-approved LRAMVA threshold and actual CDM results in the LRAMVA.[52]

Any requests for approval of lost revenues related to peak demand savings from demand response programs can only be part of a rebasing application due to the complexity and unique nature of the calculation of lost revenues from peak demand savings.

The following information should be provided in the application:

- A statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition.
- A statement confirming that the LRAMVA balance is based on verified savings results that are supported by the distributor's final CDM Annual Report and Persistence Savings Report issued by the IESO, where available. Reports must be filed in Excel format.

[52] Originally issued on December 19, 2014, updated on August 11, 2016.

- A statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation.
- A summary table showing the principal and carrying charges amounts by rate class and the resultant rate riders for each rate class. Projected carrying charges related to the disposition should be calculated in the LRAMVA work form.
- A statement confirming the period of rate recovery.
- Rationale must be provided for disposing the balance in the LRAMVA, if one or more rate classes do not generate significant rate riders.
- Details for the forecasted CDM savings included in the LRAMVA calculation including reference to the OEB's approval, or an explanation if there are no forecast CDM savings.
- A statement explaining how the rate class allocations for actual CDM savings are determined by customer class and program for each year.
- A statement confirming whether additional documentation or data was provided in support of projects that were not included in the LDC's Final CDM Annual Report (e.g. streetlighting projects). Distributors billing data by project must be included in the work form in Tab 8 of the LRAMVA work form, as applicable.
- For a distributor's streetlighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided:
  - Explanation of the methodology to calculate streetlighting savings
  - Confirmation whether the streetlighting project(s) received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings
- For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:
  - Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application.
  - Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed (for example, other upgrades under normal asset management plans).
  - Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings (for example, if requesting lost revenue recovery for the demand savings from a street light upgrade program, the associated energy savings from the Retrofit program have been subtracted from the Retrofit total).
  - Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program.
  - A table, in live excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade

project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb).

- For the recovery of lost revenues related to energy and demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information:
    - The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different from the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate.
    - Rationale for net-to-gross assumptions used
    - Breakdown of billed demand and detailed level calculations in live excel format
- If not already filed in support of a previous LRAMVA application, distributors should provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available. These reports should be filed in excel format, similar to the previous Final Verified Annual Reports from 2015 to 2017.
- If a distributor seeks to claim program savings:
    - Related to CFF programs: an explanation must be provided as to how savings have been estimated based on the available data (i.e. IESO's Participation & Cost Reports) and/or rationale to justify the eligibility of the program savings.
    - Related to other programs delivered by a distributor, including programs delivered by a distributor through the Local Program Fund under the Interim CDM Framework: an explanation and rationale should be provided to justify the eligibility of the additional program savings.

Appendix A

Appendix A: Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

For any costs incurred to make investments that are eligible for rate protection as described in section 79.1 of the OEB Act and O.Reg. 330/09 under the OEB Act, including any facilities forecast to enter service beyond the test year, the distributor may seek approval to recover the rate protection component of the costs. The distributor must provide a proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09, taking into account the OEB's Report on the Framework for Determining Direct Benefits[53] (the Direct Benefits Report). If eligible investments are approved by the OEB, a variance account is used to record the actual costs of the investments, and revenue received from the Independent Electicity System Operator (IESO) pursuant to the provincial pooling mechanism set out in section 79.1 of the OEB Act. Distributors should refer to the OEB's March 2015 APH Guidance for further information.

For renewable generation connection investments, distributors can assume the direct benefit percentage to be 17%; for renewable enabling improvement investments, the assumed direct benefit percentage is 6%. Distributors will continue to have the option to undertake a more rigorous "detailed" direct benefit assessment based on the criteria set out in the Direct Benefits Report where the distributor believes the standard percentages will not be reflective of the direct benefits of its project(s). The component of such investments not eligible for rate protection will be treated the same as any other new capital investment undertaken by a distributor, and will not be separately tracked.

Appendices 2-FA through 2-FC must be filed, identifying all material eligible investments (to a maximum of five years) for which rate protection is required. These appendices form the mechanism to calculate the applied-for 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 in accordance with O.Reg. 330/09.

For distributors that are already receiving rate protection as a result of a previous application and approval (in many cases, based on a forecast of capital expenditures on qualifying connection assets), the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold in section 2.0.9.

[53] EB-2009-0349