ONTARIO ENERGY BOARD

Handbook to Electricity Distributor and Transmitter Consolidations

Rate-making Considerations and Filing Requirements for Consolidation Applications

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Ontario

Ontario Energy Board

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1. INTRODUCTION AND BACKGROUND

The Ontario Energy Board (OEB) developed and issued an original version of this Handbook in January 2016, to provide guidance to applicants and stakeholders on applications to the OEB for approval of distributor and transmitter consolidations and subsequent rate applications. This Handbook uses the term consolidation to be inclusive of mergers, acquisitions, amalgamations and divestitures (MAADs).

In July 2023, the OEB initiated a consultation to review and update the OEB's 2016 Handbook and associated filing requirements for consolidation applications.[1] The review leveraged the OEB's experience to-date of consolidation-related decisions; identified and addressed any continuing barriers to consolidation while ensuring that customers are protected; and considered whether there are areas of the consolidation policy that may benefit from modification or guidance. The consultation also addressed the recommendations related to consolidations as outlined in the Office of the Auditor General of Ontario's Value for Money audit report entitled *Ontario Energy Board: Electricity Oversight and Consumer Protection* (OAGO Audit Report).[2]

This revised Handbook reflects updates on OEB policies and filing requirements applicable to consolidations. It also reflects updates to rate-making considerations, accounting and other matters related to consolidating utilities, as informed by comments received from stakeholders during the consultation. Section 6 of this Handbook outlines the OEB's post-consolidation monitoring and reporting requirements.

Application of the policies herein will create a more predictable regulatory environment for applicants that are considering consolidation, thereby facilitating planning and decision-making, while assisting applicants in determining the value of consolidation transactions.

Consolidation is expected to enable distributors to address challenges in an evolving electricity industry. Emerging challenges facing the energy sector include (among others) impacts of net-zero carbon initiatives such as increased use of electric vehicles and other electrification initiatives: challenges related to cybersecurity; the need for system resiliency in the face of climate change; management of distributed energy resources, and considerations of distribution system operator models. Distributors will need considerable additional investment to meet these challenges, and

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[1] EB-2023-0188, Evaluation of Policy on Utility Consolidations

[2] Office of the Auditor General of Ontario Value for Money Audit: Ontario Energy Board: Electricity Oversight and Consumer Protection, November 2022, pp. 43-44

consolidation generally offers larger utilities better access to capital markets, with lower financing costs, and opportunities to better realize resulting operational efficiencies. While consolidation is not the only way to meet these challenges, economies of scale resulting from further consolidation may enhance a distributor's capabilities to address them.

Distributors are also expected to meet public policy goals relating to electricity conservation and demand management and innovation. Delivering on these public policy goals will require capabilities that may be more cost effective for larger distributors to develop or retain.

There are various other transactions or arrangements that might be pursued for strategic or other reasons. Some of which are MAADs transactions that are subject to OEB approval under section 86 of the *Ontario Energy Board Act, 1998* (OEB Act), while others are not. The OEB recognizes that some of these other transactions or arrangements can facilitate the delivery of innovative and more cost-effective distribution services. This can be beneficial to both shareholders and ratepayers. It is not the OEB's intention to discourage distributors from pursuing transactions or arrangements that increase efficiencies.

The OEB has a statutory obligation to review and approve consolidation transactions where they are in the public interest. In discharging its mandate, the OEB is committed to reducing regulatory barriers to consolidation. To facilitate both a thorough and timely review of requests for approval of transactions, in this Handbook the OEB provides guidance on the process for review of an application, the information the OEB expects to receive in support, and the approach it will take in assessing the merits of the consolidation in meeting the public interest.

OEB policies and decisions on consolidation applications have already established several principles to create a more predictable regulatory environment for applicants.

This Handbook provides further clarity to applicants, investors, shareholders, and other stakeholders to reflect changes in policy, arising issues and experience from OEB decisions in consolidation and rate applications of consolidated utilities since 2016.

The policies and filing requirements documented in this Handbook and filing requirements supersede those in the previous version.

While the Handbook is applicable to both electricity distributors and transmitters, most of the OEB's policies and prior OEB decisions have related to distributors. Transmitters should consider the intent of the Handbook and make appropriate modifications as needed to reflect differences in transmitter consolidations, including considering Section 6 and proposing post-consolidation monitoring and reporting.

The Handbook does not automatically apply to consolidation applications in the natural gas sector filed and decided upon under section 43 of the OEB Act. The OEB panel deciding a section 43 application may decide whether the policies, options and requirements documented herein should apply in whole, in part, or not at all, based on the circumstances and supporting documentation filed in a specific application.

This Handbook documents OEB policy. Similar to other policies, OEB panels considering individual applications are not bound by the OEB's policy, and where justified by specific circumstances, may choose to apply or not to apply the policy (or to apply a part of the policy).

2. THE OEB AUTHORITY AND REVIEW PROCESS

This section describes the OEB's legal authority in approving consolidation applications and clarifies how the OEB reviews these applications.

2.1 The OEB Legislative Authority

OEB approval is required for transactions described under section 86 of the OEB Act (For ease of reference, section 86 is reproduced in Schedule 1 of this Handbook.) Briefly, these transactions are as follows:

- A distributor or transmitter sells or otherwise disposes of its distribution or transmission system as an entirety or substantially as an entirety to another distributor
- A distributor or transmitter sells a part of a distribution or transmission system that is necessary in serving the public
- A distributor or transmitter amalgamates with another distributor or transmitter
- A person acquires voting securities of a transmitter or distributor or acquires control of a corporation with voting shares

Section 86(2) relating to voting securities does not, however, apply to the acquisition or sale of shares in Hydro One, a company created by the Crown under section 50(1) of the *Electricity Act, 1998*, which is explicitly exempt under section 86(2.1) from the conditions stipulated in section 86(2).

2.2 The Application Review Process

This Handbook applies specifically to applications under sections 86(1)(a) and (c) and sections 86(2)(a) and (b) of the OEB Act, which are processed through the OEB's adjudicative review process. Sections 86(1)(a) and (c) of the OEB Act relate to asset sales and amalgamations. Section 86(2) of the OEB Act relates to voting securities. To assist applicants, the Filing Requirements for Consolidation Applications in Schedule 2 of this Handbook set out the information that needs to be provided in an application.

Applications filed under section 86(1)(b) of the OEB Act are typically determined by OEB staff acting under delegated authority under section 6 of the OEB Act without a hearing. These applications generally include the sale of specific distribution or transmission assets from one distributor or transmitter to another, or to a large consumer who is served by the same assets. For these applications, applicants should continue using the form entitled *Application Form for Applications under Section 86(1)(b) of the OEB Act* that is posted on the OEB's website.

The OEB may elect to process a section 86(1)(b) application under its adjudicative review process if the OEB considers that certain aspects of an application could affect service to the public and/or have a material effect on rates.[3] This will be determined once the application is filed with the OEB. In those circumstances, this Handbook, or parts of it, will be applicable. If there is any question, the OEB suggests that applicants who are of the view that their transaction is material should use this Handbook to inform their application.

If an applicant believes that certain requirements do not apply in its circumstances, the application should include reasoning with supporting justification. Applicants may wish to contact the OEB through an Industry Relations Enquiry or contact OEB staff to discuss the matter.

3. THE OEB TEST – THE "NO HARM" TEST

In reviewing an application by a distributor for approval of a consolidation transaction, the OEB has, and will continue, to apply its "no harm" test. The "no harm" test was first established by the OEB in 2005 through an adjudicative proceeding (the Combined Proceeding).[4]

[3] These applications may be decided by OEB staff acting under delegated authority under section 6 of the OEB Act, or by an OEB panel of Commissioners.

[4] Combined Proceeding Decision - OEB File No. RP-2005-0018/EB-2005-0234/EB-2005-0254/EB-2005-0257

In carrying out its responsibilities, the OEB is guided by statutory objectives set out in section 1 of the OEB Act. The "no harm" test considers whether the proposed transaction is expected to have an adverse effect on the matters prescribed in these statutory objectives. The OEB will consider whether the "no harm" test is satisfied based on an assessment of the cumulative effect of the transaction on the matters prescribed in its statutory objectives. If the proposed transaction is expected to have a positive or neutral effect on these matters, the OEB will approve the application. The definition of the "no harm" test is not a colloquial understanding of "no harm" but is based on the tests laid out in the MAADs policy.

The OEB's statutory objectives are:

1. To inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service.
2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
4. To facilitate innovation in the electricity sector.

4. THE OEB ASSESSMENT OF THE APPLICATION

This section sets out how the OEB applies the "no harm" test within the context of the performance-based regulatory framework, the *Renewed Regulatory Framework* (RRF).[5] This framework was established by the OEB in 2012 to ensure that regulated distribution companies operate efficiently, cost effectively and deliver outcomes valued by its customers and in 2016 was extended to all rate regulated utilities.[6]

4.1 The Renewed Regulatory Framework

Ongoing performance improvement and performance monitoring are underlying principles of the RRF. The OEB's oversight of utility performance relies on the establishment of performance standards to be met by

[5] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012

[6] *Handbook to Utility Rate Applications*, October 13, 2016, p. 4

distributors, ongoing reporting to the OEB by distributors, and ongoing monitoring of distributor achievement against these standards by the OEB.

An electricity distributor is required, as a condition of its licence, to provide information about its distribution business. Metrics are used by the OEB to assess a distributor's services, such as frequency of power outages, financial performance and costs per customer. The OEB uses this information to monitor an individual distributor's performance and to compare performance across the sector. The OEB also has a robust audit and compliance program to test the accuracy of reporting by distributors.

As part of the regulatory framework, distributors are expected to achieve certain outcomes that provide value for money for customers. One of these outcomes is operational effectiveness, which requires continuous improvement in productivity and cost performance by distributors and that utilities deliver on system reliability and quality objectives. The OEB uses processes to hold all utilities to a high standard of efficiency and effectiveness.

The OEB has a proactive performance monitoring framework that inherently protects electricity customers from harm related to service quality and reliability and has established the mechanisms to intervene if corrective action is warranted. The OEB will be informed by the metrics that are used to evaluate a distributor's performance in assessing a proposed consolidation transaction.

All of these measures are in place to ensure that distributors meet expectations regardless of their corporate structure or ownership. The OEB assesses applications for consolidation within the context of this regulatory framework.

4.2 The "No Harm" Test

The "no harm" test assesses whether the proposed transaction are expected to have an adverse effect on the matters prescribed in the OEB's statutory objectives. In assessing "no harm", both quantitative (e.g., cost) and qualitative information (e.g., customer services) included in the application will be weighed by the OEB in consideration of the circumstances of each case to determine whether the proposed transaction, on a net basis, has a positive or neutral effect on the matters prescribed in the OEB's objectives.

Qualitative and quantitative forecasts of expected efficiencies and savings provided in a consolidation application offer context to measure what a consolidated entity believes can be achieved as a result of a transaction. The OEB uses this information to assess a proposed transaction. At the time of the rebasing application of the consolidated entity, the OEB reviews the achieved results and the consolidated entity's rate-setting proposals to determine whether they are satisfactory, or if any corrective measures need to be taken (e.g., potential disallowance of proposed costs at rebasing).

While the OEB has broad statutory objectives, in applying the “no harm” test, the OEB has primarily focused its review on impacts of the proposed transaction on price and quality of service to customers, and the cost effectiveness, economic efficiency and financial viability of the electricity distribution sector. The OEB considers this to be an appropriate approach, given the performance-based regulatory framework under which all regulated distributors are required to operate and the OEB’s existing performance monitoring framework. This does not preclude applicants from detailing how a proposed transaction may help promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario and help facilitate innovation in the electricity sector generally. However, the OEB typically does not consider consolidations to have adverse impacts in respect of these other objectives, and the OEB has guidelines and initiatives to address them.

For example, in March 2024, the OEB issued the *Non-Wires Solutions Guidelines for Electricity Distributors* which replaces the OEB’s Conservation and Demand Management Guidelines for Electricity Distributors.[7] With guidelines in place, the OEB is satisfied that its objective to promote electricity conservation and demand management will not be adversely affected by a consolidation.

The OEB has and will continue initiatives to facilitate innovation in the electricity sector. An example includes the OEB’s Innovation Sandbox which supports pilot projects testing new activities, services and business models in Ontario’s electricity and natural gas sectors. The OEB does not consider that its objective to facilitate innovation will be adversely affected by consolidations. The OEB is of the view that consolidations may help facilitate innovation by better enabling distributors to address challenges in an evolving electricity industry.

[7] EB-2024-0118, *Non-Wires Solutions Guidelines for Electricity Distributors*, March 28, 2024. The change in name reflects the fact that non-wires solutions to address system needs can encompass a broader range of solutions than traditional conservation and demand management, including, but not limited to, third-party distributed energy resources such as energy storage and distributed (embedded) generation. Certain aspects of the NWS Guidelines are also relevant to rate-regulated transmitters and natural gas distributors (p. 3)

4.3 Scope of the Review

The factors that the OEB will consider in detail in reviewing a proposed transaction are as follows:

Objective 1 – Protect consumers with respect to price and the adequacy, reliability and quality of electricity service

Price

A simple comparison of current rates between consolidating distributors does not reveal the potential for lower cost service delivery. These entities may have dissimilar service territories, each with a different customer mix resulting in differing rate class structure characteristics. For these reasons, the OEB will assess the underlying cost structures of the consolidating utilities. As distribution rates are based on a distributor's current and projected costs, it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors. A key expectation of the RRF is continuous improvement in productivity and cost performance by distributors. The OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers.

Consistent with past decisions,[8] the OEB will not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of "no harm" as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term. In reviewing a transaction, the OEB must consider the long-term effect of the consolidation on customers and the financial sustainability of the sector.

To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. The OEB will take into consideration any evidence which highlights expected impacts to cost structures from an evolving energy sector relative to the status quo, with detailed supporting rationale. The OEB will weigh both the quantitative and qualitative impacts of a proposed transaction and consider the circumstances of each case to

[8] For example, Hydro One Inc./Norfolk Power Distribution Inc. – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198, Hydro One Inc./Haldimand County Hydro Inc. – OEB File No. EB-2014-0244

determine whether the proposed transaction, on a net basis, has a positive or neutral effect on the attainment of the OEB's objectives.

The OEB considers revenue requirement to be a suitable proxy for cost structure comparisons between the proposed consolidating utilities and the status quo scenario (i.e., in the absence of the transaction).

A utility is expected to provide a forecast of revenue requirements for both the consolidation and status quo (separate LDCs) scenarios over the deferred rebasing period and including the future post-consolidation rebasing year. This forecast should consider, among other factors, the forecasted cumulative impact of price cap adjustments and growth. Assumptions used in these forecasts must also be clearly documented in the application (e.g., inflation, productivity, cost of service adjustments, evolving energy sector, expected Incremental Capital Module requests (timing and quanta), if applicable, etc.).

Presentations of cost structure analyses should be based on a utility's assessment of its future operating needs over its elected deferred rebasing period. Factors including, but not limited to potential historical underinvestment, safety considerations and an evolving energy sector all may contribute to anticipated changes in underlying cost structures.

In a consolidation application, this forecast cost-related analysis provides evidence relating to one aspect of the "no harm" test based on current information and also is one component of what the OEB will use to assess whether to approve a transaction.

Equally important are the achieved results of efficiencies, synergies, and any unanticipated cost increases, etc., to a distributor's underlying cost structure. At the time of rebasing, the OEB expects the consolidated utility to produce an updated analysis comparing the revenue requirements for the consolidated entity and the status quo (separate LDCs), based on information available on a reasonable efforts basis.[9]

It is understood that the environment in which utilities operate may have evolved from the time of the consolidation application to the rebasing application. The intent of providing forecasts with associated assumptions as part of the consolidation application, and then updating those forecasts at rebasing, is to assist the utility, the OEB and other stakeholders in understanding what may have changed during the deferred rebasing period. This, in turn, will aid in parties' and the OEB's assessment of the reasonableness of the consolidated entities' revenue requirement at the time of the rebasing application. The OEB

[9] This would, of necessity, include forecasts for the bridge year (the last year of the deferred rebasing) and the rebasing test year.

panel deciding on the rebasing application will take that evidence into consideration when making its determinations.

Details of the OEB's expectations regarding these matters are outlined in the filing requirements attached as Schedule 2.

While the implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility.

Adequacy, reliability and quality of electricity service

In considering the impact of a proposed transaction on the adequacy, quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

The OEB's *Report of the Board: Electricity Distribution Systems Reliability Measures and Expectations*, issued on August 25, 2015 sets out the OEB's expectations on the level of reliability performance by distributors. In the Report, the OEB noted that continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or to maintain the same level of performance at a reduced cost.

Under the OEB's regulatory framework, utilities are expected to deliver continuous improvement for both reliability and service quality performance to benefit customers. This continuous improvement is expected to continue after a consolidation and will continue to be monitored for the consolidated entity under the same established requirements.

Because the enhancement of system reliability and hardening in light of climate change and an evolving energy sector are becoming more important, utilities are encouraged to discuss in their applications how a proposed consolidation transaction will provide benefits for consumers in these areas.

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

The impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity) will be assessed based on the applicant's identification of the various aspects of utility operations where it expects sustained operational efficiencies, both quantitative and qualitative.

The impact of a proposed transaction on the acquiring utility's financial viability for an acquisition, or on the financial viability of the consolidated entity in the case of a merger will also be assessed. The OEB's primary considerations in this regard are:

- The effect of the purchase price, including any premium paid above the historic (book) value of the assets involved
- The financing of incremental costs (transaction and transition costs) to implement the consolidation transaction

In the Combined Proceeding decision, the OEB made it clear that the selling price of a utility is relevant only if the price paid is so high as to create a financial burden on the acquiring company. This remains the relevant test. While there may not be a premium involved with mergers, the OEB will nevertheless consider the financial viability of the newly consolidated entity.

Electricity distribution rates are currently based on a return on the historic value of the assets. If a premium has been paid above the historic value, this premium is not recoverable through distribution rates and no return can be earned on the premium. A shareholder may recover the premium over time through savings generated from efficiencies of the consolidated entity. In considering the appropriateness of purchase price or the quantum of the premium that has been offered, only the effect of the purchase price on the underlying cost structures and financial viability of the regulated utilities will be reviewed. Specifically, the OEB will test the financial ratios and borrowing capacity of the resulting entity, as the improvement in financial strength is one of the expected underlying benefits of consolidation.

Incremental transaction and transition costs are not generally recoverable through rates. If an applicant considers that it has unique circumstances which may warrant recovery of transaction and/or transition costs, evidence and justification to demonstrate such unique circumstances should be brought forth in the consolidation application for OEB consideration.

Transaction costs can be defined as costs incurred that are directly attributable to the development of the proposed transaction and its execution.

Transition costs can be defined as costs that are attributable to the consolidation, and often relate to being able to operationalize efficiencies that the consolidation enables. At some point, further efforts to execute operational savings should be considered "normal business" operations of the consolidated utility, and not transitional costs and efficiencies.

Distributors have indicated that transaction and transition costs are significant and that recovery of these costs can be a barrier to consolidation. To address distributors' concerns, the OEB's policy provides the opportunity for distributors to defer rebasing for a period up to ten years following the closing of a consolidation transaction.[10] This deferred rebasing period is intended to enable distributors to fully realize anticipated efficiency gains from the transaction and retain achieved savings for a period of time to help offset the costs of the transaction.

Most transaction and transition costs from recent consolidation applications have been expensed. Since expensed transition and transaction costs are temporary and time-limited, it is presumed that they will not be a consideration at the next rebasing application (and that they were recovered through savings achieved during the deferred rebasing period or from shareholders).

If a utility has capitalized any assets it has classified as part of the utility's "transition" costs (i.e., capitalized costs intended to integrate operations) these will be subject to review, on a case-by-case basis. The nature of the expenditure and whether it would have occurred regardless of the consolidation will be reviewed, in addition to the typical review for need and prudence. The OEB will determine whether it is appropriate to include the remaining book value of these capitalized costs in the opening test year rate base or whether there was an expectation that these costs be recovered through the consolidation savings.

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The OEB considers that certain aspects of a consolidation transaction are not relevant in assessing whether the transaction is in the public interest, either because they are out of scope, or because the OEB has other approaches and instruments for ensuring that statutory objectives will be met. Accordingly, the OEB will not require applicants to file evidence on the following matters as part of a consolidation application.

1. Deliberations, activities, and documents leading up to the final transaction agreement

The question for the OEB is neither the why nor the how of the proposed transaction. The application of the "no harm" test is limited to the effect of the proposed transaction before the OEB when considered in light of the OEB's statutory objectives.[11]

It is not the OEB's role to determine whether another transaction, whether real or potential, can have a more positive effect than the transaction that has been placed before the OEB. Accordingly, the OEB will not consider, whether

[10] Established in the *Report of the Board: Rate-making Associated with Distributor Consolidation*, March 26, 2015

[11] EB-2013-0196/EB-2013-0187/EB-2013-0198, Hydro One Inc./Norfolk Power Distribution Inc. Decision and Order and Procedural Order No. 8; EB-2014-0213, Hydro One Inc./Woodstock Hydro Services Inc. Decision and Procedural Order No. 4

a purchasing, selling, or amalgamating utility could have achieved a better transaction than that being put forward for approval in the application.

The OEB will not consider issues relating to the overall merits or rationale for applicants' consolidation plans nor the negotiating strategies or positions of the parties to the transaction. The OEB will not consider issues relating to the extent of the due diligence, the degree of public consultation or public disclosure by the parties leading up to the filing of the transaction with the OEB.

Applicants and stakeholders should not file any of the following types of information as they are not considered relevant to the proceeding:

- Draft share purchase agreements and other draft confidential agreements and documents utilized in the course of the negotiation process
- Negotiating strategies or conduct of the parties involved in the transaction
- Details of public consultation prior to the filing of the application

2. Implementing public policy requirements for promoting conservation, facilitating innovation

The OEB's performance-based regulation, which includes performance monitoring and reporting based on standards, combined with the regulatory instruments of guidelines, codes and licences, establishes a framework for success in achieving public policy requirements. A utility that does not meet established performance expectations is subject to corrective action by the OEB. Given these means for ensuring that public policy objectives are met by all regulated entities, the OEB is satisfied that the "no harm" test will be met for these objectives following a consolidation and there is no need or merit in further detailed consideration as part of a consolidation transaction. For these reasons, no evidence is required to be filed for these issues. As stated previously, this does not preclude applicants from identifying how a proposed transaction could promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario and facilitate innovation in the electricity sector generally.

3. Prices not related to a utility's own costs

The OEB's review is limited to the components of the distribution business and the costs and services directly under a distributor's control. For example, one of the mandates of a distributor is to pass-through certain wholesale market and commodity related costs to customers. These costs are passed through and not part of a utility's underlying costs to serve its customers. Accordingly, the prices of these services are not considered by the OEB in its review of a consolidation application.

However, if the consolidation or a decision by the consolidated utility post-consolidation will affect how the utility will track and bill for pass-through costs by rate zones, the proposal for this must be provided in the consolidation application. For example, changes in wholesale metering configuration.

5. RATE-MAKING CONSIDERATIONS ASSOCIATED WITH CONSOLIDATION APPLICATIONS

The OEB's policies on rate-making matters associated with consolidation in the electricity distribution sector were originally set out in two reports of the OEB. The first report titled "*Report of the Board: Rate-making Associated with Distributor Consolidation*" issued on July 23, 2007 (2007 Report) was supplemented by the 2015 Report, issued under the same name.[12]

This section of the Handbook consolidates information that is provided in these two reports, and incorporates any changes, additions or clarifications resulting from the OEB's consultation launched in 2023.[13] This section of the Handbook identifies the key rate-making considerations expected to arise in consolidation transactions. This Handbook replaces the OEB's consolidation policy documents on rate-making matters associated with consolidation in the electricity distribution sector (2007 Report and 2015 Report), as well as the 2016 Handbook. Applicants, however, may wish to review both reports in preparing their applications for both the consolidation transaction and subsequent rate application for background information.

Rate-setting following a consolidation will not be addressed in an application for approval of a consolidation transaction unless there is a rate proposal that is an integral aspect of the consolidation e.g., a temporary rate reduction. Rate-setting for the consolidated entity will be addressed in a separate rate application, in accordance with the rate setting policies established by the OEB. The OEB's review and approval of a consolidated utility's revenue requirement, and the establishment of distribution rates paid by customers, occurs through an open, fair, transparent and robust process ensuring the protection of customers.

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[12] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015

[13] EB-2023-0188, Evaluation of Policy on Utility Consolidations

Rate-Setting Policies

The rate making considerations relating to consolidation that applicants and parties need to be aware of are:

- Deferred Rebasing
    - Multiple Transactions
- Early Termination of Pre-Consolidation Rate-Setting term
- Early Termination or Extension of Deferred Rebasing Period
- Rate Setting During Deferred Rebasing Period
- Off Ramp
- Earnings Sharing Mechanism
- Incremental Capital Investments During Deferred Rebasing Period
- Future Rate Structures and Rate Harmonization
- Accounting Matters

5.1 Deferred Rebasing

The setting of rates for a consolidated entity using a cost of service methodology or a Custom Incentive Rate-setting method (both referred to in this document as rebasing of rates) involves a detailed assessment by the OEB of a utility's underlying costs. A consolidated entity is required to file a separate application with the OEB under section 78 of the OEB Act for a rebasing of its rates. This typically takes place at some point in time following the OEB's approval of a consolidation.

To encourage consolidations and provide distributors with the flexibility to manage their own circumstances, the OEB provides consolidating distributors with an opportunity to offset transaction and transition costs with achieved savings. The OEB has previously recognized that providing a reasonable opportunity to use savings to at least offset the costs of a MAADs transaction is an important factor in a utility's consideration of the merits of a given consolidation initiative. The OEB permits consolidating distributors to defer rebasing for up to ten years from the closing of the transaction.[14]

The extent of the deferred rebasing period is at the option of the distributor and no supporting evidence is required to justify the selection of the deferred rebasing period subject to the minimum requirements set out below.

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[14] *Report of the Board: Rate making Associated with Distributor Consolidation*, March 26, 2015, p. 6

While the OEB has determined that allowing a maximum 10-year deferred rebasing period is appropriate to incent consolidation, there must be an appropriate balance between the incentives provided to utilities and the protection provided to customers. The OEB will therefore require consolidating distributors to identify in their consolidation application the specific number of years for which they choose to defer rebasing. Distributors must select a definitive timeframe for the deferred rebasing period. This will allow the OEB to assess any proposed departure from this stated plan. Applicants must also identify the rate year and effective date for rebased rates at the end of the elected deferred rebasing period. This will provide greater certainty for planning purposes and will better inform ratepayers of the utility's intentions.

In addition, distributors cannot select a deferred rebasing period that is shorter than the shortest remaining term of one of the consolidating distributors, subject to the requirements set out in the section "Early Termination of Pre-Consolidation Rate-setting Term".

The OEB requires that for any elected deferral period longer than five years, the OEB will require the consolidating entity to implement an earnings sharing mechanism. More details are provided in the Earning Sharing Mechanism section of this Handbook.

Further, if a consolidating entity elects to defer rebasing for more than five years (i.e., six to ten years), a mid-term report must be filed detailing the progress to date on steps the distributor has taken toward integration. At the time of the consolidated entity's first rebasing application post-consolidation, the OEB expects the consolidated utility to provide updates to this information based on achieved results, including for any period not covered by the initial mid-term report. For distributors that elect to defer rebasing for less than five years, a similar report is required, but only at the time of post-consolidation rebasing application. More details are provided in the Post-Consolidation Monitoring and Reporting section of this Handbook.

The OEB will continue to make use of its monitoring tools to determine whether the results of MAADs transactions for consumers and the industry warrant additional consumer protection measures. If so, future changes to the policy may be considered.

Multiple Transactions

Future consolidations may involve several consolidating distributors as well as the possibility of successive consolidation transactions by a previously consolidated entity. While a distributor should have some flexibility with respect to its deferred rebasing period if it enters a further consolidation transaction before the end of the deferral period, this flexibility should be limited to protect the interest of consumers. A consolidated distributor retaining savings on a continuing basis rather than sharing any savings with ratepayers and delaying a review of costs, operations and rates by the OEB would not be in the public interest.

Schedule A outlines the OEB's filing requirements relating to the deferred rebasing period for a proposed transaction in which a distributor already in a deferred rebasing period (as a result of a previously approved consolidation) amalgamates with or acquires another distributor not in a deferred rebasing period as a result of a prior consolidation. The OEB's requirements in this scenario remove the potential for the deferral of rebasing indefinitely.

The OEB recognizes that the situation documented above is one of many that can be encountered in the future. It is not prudent or reasonable for the OEB to reflect all scenarios without consideration of evidence. Each transaction may offer the potential for different benefits that vary in nature and timing. For circumstances not covered in this Handbook, the OEB needs to ensure ratepayers are not disadvantaged. In some consecutive consolidations entered near the end of a deferral period, extending the deferral period may not be appropriate. The onus is on the applicant(s) to justify any proposal for their deferred rebasing period involving multiple transactions and demonstrate that ratepayers will not be adversely affected.

5.2 Early Termination of Pre-Consolidation Rate-setting Term

At the time distributors first enter into a consolidation transaction, consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates.

A consolidated entity may apply to the OEB to rebase its rates as a consolidated entity through a cost of service or Custom IR application following the expiry of the original rate-setting term of at least one of the consolidating entities and once the selected deferred rebasing period has concluded. If, however, a consolidated entity wishes to rebase its rates prior to the end of the pre-consolidation rate-setting term of the distributor that has the earliest termination date, the consolidated entity must demonstrate the need for this “early rebasing” as part of the early rebasing application.

The OEB established its approach to early rebasing in a letter dated April 20, 2010 and reiterated it in the RRF. The OEB expects a distributor that seeks to have its rates rebased earlier than scheduled to clearly demonstrate why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remaining years of its current rate term.

5.3 Early Termination or Extension of Selected Deferred Rebasing Period

The OEB considers that consolidations can provide for greater efficiencies and benefits to customers and is committed to reducing regulatory barriers to consolidations. Therefore, the OEB will be open to requests for early termination of extended deferral periods. During the deferred rebasing period, specifically not earlier than during year four, a consolidated entity may apply to the OEB to terminate its deferral period and rebase the consolidated entity (if the deferral period initially elected is longer than four years).[15] The application will allow the OEB to establish rates that reflect the efficiencies from the consolidation transaction.

A consolidated entity that seeks to rebase earlier than its elected deferral period should inform the OEB of its intent and provide sufficient reasons for the request. Examples for such a request may include an Asset Condition Assessment that shows significant investment is needed (not known at the time of consolidation), or a significant new requirement imposed that cannot be addressed through existing means.

A consolidating entity that selected a deferred rebasing period of less than ten years in its application may seek to extend its deferred rebasing period. However, the OEB notes that if a consolidated entity seeks to extend its deferred rebasing period (up to the ten-year maximum), it must file supporting and compelling rationale for the extension. The OEB will consider the reasons and information provided, including other relevant factors such as the distributor’s financial and service quality performance. An example of a circumstance in which it may be reasonable to make such a request is if a consolidated utility needs a longer than expected deferral period to offset transaction and transition costs with efficiency savings.

If a consolidated entity seeks to amend (i.e., shorten or extend) its deferred rebasing period, the OEB will consider whether approval of such a request is in the public interest.

5.4 Rate Setting during Deferred Rebasing Period

Under the OEB’s RRF, there are three rate-setting options: Price Cap Incentive Rate-Setting (Price Cap IR or PCIR), Custom Incentive Rate-

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[15] Based on the assumption that the last rebasing year was the year prior to the first full year of consolidation, “after year four” would align with the OEB’s five-year rate plan if a utility chose to rebase in the first year it had an opportunity to do so.

Setting (Custom IR or CIR) and Annual Incentive Rate-Setting Index (Annual IR Index or AIRI). The term of the Price Cap IR and Custom IR options is normally five years. The Annual IR Index option has no specific term.

Consolidating distributors may be on any one of the rate-setting mechanisms and may not necessarily be using the same rate-setting mechanism or have the same termination dates. Rates will be set for a distributor who is a party to a consolidation transaction during any deferred rebasing period after the distributor’s original incentive rate-setting plan has concluded as follows:

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on Custom IR, whose plan expires, would move to having rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on the Annual IR Index plan may move to the Price Cap IR plan[16] or may continue to have rates based on the Annual IR Index.

Table 1 below illustrates six potential scenarios for rate-setting during the deferred rebasing period, assuming the consolidation of two distributors. The table also sets out the conditions that must be met by a consolidated entity that elects to rebase its rates. The table provides guidance on rebasing for the first rate-setting period after the consolidation but does not provide guidance on subsequent rebasing applications in the event of multiple transactions. While Table 1 is intended to illustrate a situation of two consolidating distributors, as stated above, the OEB is aware that future consolidations may involve several consolidating distributors as well as the possibility of multiple successive consolidation transactions by a single consolidated entity. For unique circumstances, the OEB expects that rate-setting proposals will need to be assessed on a case-by-case basis.

[16] This became effective with 2023 rates to provide a further incentive for distributors considering consolidation. See OEB’s December 1, 2021 letter - *Applications for 2023 Electricity Distribution Rates*. A distributor on the Annual IR Index plan and not in a current deferral period arising out of a consolidation must still rebase before moving to the Price Cap IR plan.

Table 1. Rate-Setting Options During the Deferred Rebasing Period

Going in Rates. As of the date of the closing of the transaction. Assumes two distributors. Assumes no amendments to originally elected deferred rebasing period sought.

	Both on PCIR	One on PCIR and one on CIR	Both on CIR
Deferral Period	Continue with current plans for chosen deferred rebasing period.	LDC on PCIR continues on current plan for chosen deferred rebasing period and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.	Continue with current plans. Once each term expires, each LDC will move to PCIR for the remaining years of the chosen deferred rebasing period.
	Or	Or	Or
Rebasing Options	Rebase as a consolidated entity following the expiration of one of the entities' term and once the selected deferred rebasing period has concluded.	LDC on PCIR continues on current plan. If its term expires in advance of the expiration of the other LDC's CIR term the consolidated entity may rebase once the selected deferred rebasing period has concluded.	Continue with current plans. Once the earlier of the two terms expires the consolidated entity may rebase once the selected deferred rebasing period has concluded.
		Or	
		If the term for the LDC on CIR expires first, the consolidated entity may rebase following the expiration of the CIR term and once the selected deferred rebasing period has concluded.	
	One on PCIR and one on AIRI	**Both on AIRI**	**One on AIRI and one on CIR**
Deferral Period	Continue with current plans for chosen deferred rebasing period. OR LDC on PCIR continues on current plan and LDC on AIRI may move to PCIR	Continue with current plans for chosen deferred rebasing period OR one or both LDCs may move to PCIR	LDC on AIRI continues on current plan for chosen deferred rebasing period or moves to PCIR and LDC on CIR moves to PCIR for the remaining years of chosen deferred rebasing period, following the expiration of the CIR term.
	Or	Or	Or
Rebasing Options	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.	Consolidated entity may rebase once the selected deferred rebasing period has concluded.

5.5 Off Ramp

As set out in the OEB's RRF, each incentive rate-setting method includes an annual return on equity (ROE) dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated by the OEB. The OEB requires consistent, meaningful and timely reporting to effectively monitor utility performance and determine if expected outcomes are being achieved. The OEB's performance monitoring framework allows the OEB to take corrective action if required, including the possible termination of the distributor's rate-setting method and requiring the distributor to have its rates rebased.

The dead band of ±300 basis points on ROE continues to apply to utilities who have deferred rebasing due to consolidation. For utilities who defer rebasing up to five years, the OEB may initiate a regulatory review if the earnings are outside of the dead band. For utilities deferring rebasing beyond five years, an earnings sharing mechanism is required above ±300 basis points as discussed in the next section.

5.6 Earnings Sharing Mechanism (ESM)

Consolidating entities that propose to defer rebasing beyond five years, must implement an ESM for the period beyond five years.[17] The ESM is designed to protect customers and ensure that they share in any increased benefits from consolidation during the deferred rebasing period.

Under the ESM, excess earnings are shared with consumers on a 50:50 basis for all earnings that are more than 300 basis points above the consolidated entity's annual ROE. Earnings will be assessed each year once audited financial results are available and excess earnings beyond 300 basis points will be shared with customers annually. No evidence is required in support of an ESM that follows the form set out in the 2015 Report.

The 300-basis point dead band is a well-established tool that the OEB has used for various purposes for many years. It is consistent with the incentive rate-setting policy for off-ramps. It is also used in the means test for advanced capital modules/incremental capital modules, and the means test for recovery of balances recorded in Account 1509 - Impacts Arising from the COVID-19 Emergency.[18] In addition, the OEB sees merit in using a default

[17] 2016 MAADs Handbook, p. 16

[18] *Report of the OEB, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014, p.15 (EB-2014-0219), and *Report of the OEB, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency*, p.15 (EB-2020-0133)

ESM approach as a starting point because using a consistent initial approach for all consolidated utilities can lead to regulatory efficiencies.

There are numerous types and structures of consolidation transactions, and there can be significant differences between utilities involved in a transaction. The ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals. For these cases, applicants are invited to propose an ESM that better achieves the objective of protecting customer interests during the deferred rebasing period.

An ESM balances the opportunity for the consolidated utility to accrue net savings to its shareholders to offset the consolidation costs while continuing to protect ratepayer interests. Regulatory efficiencies can be gained if any excess earnings recorded in an ESM account are requested for disposition in the consolidated utility’s next rebasing application instead of in the annual Incentive Rate Mechanism (IRM) application. An ESM account is a Group 2 account - requesting the disposition of the ESM account balance at rebasing would be consistent with the OEB’s disposition policy for Group 2 accounts.[19] A prudence review of the account for all years of the ESM can be conducted at the time of the rebasing application, rather than reviewing balances annually in an IRM rate application, which is intended to be a mechanistic process. Furthermore, the results of the ESM calculation can be considered along with any other MAADs considerations required at the time of the next rebasing application. If the audited ESM balances covering all applicable years of the rate term are not available at the time of the next rebasing application, then the outstanding balance(s) shall be brought forward for disposition in the subsequent IRM application(s) following the next rebasing application. For example, the audited bridge year balance in the ESM account may not be available at the time of rebasing.

The ESM shall be calculated annually on a calendar-year basis. The ESM calculation should include all transaction and transition costs, as well as savings. An annual ESM calculation rather than a cumulative ESM calculation should be used to determine ESM balances that are requested for disposition at rebasing.

Utilities should provide an update of the audited ESM balance in each of their IRM or Custom IR Update applications for all applicable years of the rate term.

Many consolidations close on dates that are not at calendar year end. Calculating ESMs on a calendar-year basis, regardless of when the MAADs transaction closed, would be efficient and practical as the data required

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[19] EB-2008-0046, *Report of the OEB, on Electricity Distributors’ Deferral and Variance Account Review Initiative (EDDVAR),* July 31, 2009, p.13

would align with the consolidated utility's financial reporting period, which is subject to the utility's financial statement external audit.

For purposes of ESM calculations, calendar year data shall be used regardless of the actual closing date of the consolidation. If a MAADs transaction closes prior to June 30 in a given year, the ESM shall be applied starting at January 1 of the same calendar year. If the MAADs transaction closes after June 30 in a given year, the ESM shall be applied starting at January 1 of the subsequent calendar year.[20]

Regarding transition and transaction costs, to the extent they continue to be incurred in the years the ESM is calculated, these costs shall be included in the ESM calculation for the years that the ESM applies. This symmetrical treatment allows for ratepayer protection while acknowledging utility costs.

At the time of consolidation, the consolidating utilities may also have differing deemed ROEs. The most appropriate way to determine a deemed ROE for the purposes of the ESM calculations for the consolidated entity shall be to weight the approved ROEs for each utility from their respective last rebasing applications, by the deemed equity component of the rate base of each utility in their last rebasing applications. The OEB has approved this approach in prior cases and does not see any reason to deviate from this approach.[21]

An accounting order shall be established in the MAADs proceeding, to take effect on the closing date of the MAADs transaction, subject to the calendar year data considerations discussed above. The OEB considers it more efficient to establish the ESM account in the MAADs proceeding, rather than revisiting the issue and establishing the account in a subsequent rate application prior to the effective date of the ESM.

Consistent with the filing requirements for cost of service applications, the accounting order must include a description of the mechanics of the account; examples of general journal entries; and the proposed account duration.[22]

[20] For example, if the ESM is effective starting in year six of the deferred rebasing period and the MAADs transaction closed on March 30, the ESM shall be calculated starting January 1 of year six. On the other hand, if the MAADs transaction closed August 1, the ESM shall be calculated starting January 1 of year seven.

[21] For example, see EB-2021-0280, Decision and Order, Brantford Power Inc. and Energy + Inc. MAADs, March 17, 2022, p. 13; and EB-2022-0006, Decision and Order, Kitchener-Wilmot Hydro Inc. Waterloo North Hydro Inc. MAADs, June 28, 2022, p. 21

[22] Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, December 15, 2022, p. 67

5.7 Incremental Capital Investments during Deferred Rebasing Period

The Incremental Capital Module (ICM) is an additional rate-setting mechanism under the Price Cap IR option. The ICM allows for funding of significant capital investments for discrete projects that are not part of typical annual capital programs during the period of incentive regulation between the cost of service applications to rebase rates. The details of the mechanism are described in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, issued on September 18, 2014 (2014 ACM Report) and in the *Report of the OEB: New Policy Options for the Funding of Capital Investments: Supplemental Report*, issued on January 22, 2016. To qualify for an ICM, the capital project must satisfy a materiality threshold to demonstrate that the incremental capital amounts are beyond the normal level of capital expenditures expected to be funded by existing rates, including the effect of customer and load growth.

Electricity distributors are eligible to apply for ICMs if they are on the:

1. Price Cap IR plan;[23] or
2. Annual IR plan and are in a MAADs deferred rebasing period.

Electricity distributors on Price Cap IR and in a deferral period associated with a utility consolidation that request ICM funding are expected to file an updated Distribution System Plan (DSP) if their ICM application falls in a rate year that is beyond the planning horizon of their previous DSP.[24]

The 2014 ACM Report states that projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs.[25] To enhance the efficiency of the regulatory process and to provide a further incentive for distributors considering consolidation, the OEB updated its ICM policy for responding to capital investment needs of electricity distributors that select an extended deferred rebasing period (beyond five years) under the OEB's MAADs policy. Specifically, the OEB provided additional flexibility for these electricity distributors to apply for incremental capital funding for an annual capital program during the extended rebasing period (i.e., years six to ten) if they can demonstrate the following:

- An urgent need for such additional funding that is based on new information that has arisen since the utility's most recent rebasing application related to the management of risk associated with asset

[23] The *OEB's December 1, 2021 letter* noted that the ICM is not available to electricity distributors on Price Cap IR for any deferral period not associated with a utility consolidation.

[24] OEB Letter, Applications for 2023 Electricity Distribution Rates, December 1, 2021, p. 3

[25] 2014 ACM Report, p. 13

condition, reliability and quality of service and public safety

- History of good utility practice in capital planning, capital program management and asset maintenance
- How the proposed ICM investment addresses customer needs and preferences and delivers benefits to customers
- Exhaustion of other available options to manage its costs within the envelope provided by the existing price cap or another applicable formula.[26]

The February 2022 letter states that electricity distributors that are in an extended MAADs deferred rebasing period would still have to meet the remaining ICM requirements, including the maximum eligible incremental capital envelope calculation, the tests of prudence, causation and materiality, and the use of the existing ICM Excel template.

With respect to the “project-specific materiality” criterion, the OEB’s 2014 ACM Report states that minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment.[27] Funding requests for annual programs are not for individual projects as anticipated when the ICM requirements were set out in the 2014 ACM Report. Whether incremental funding requests for annual capital programs for a utility in a deferred rebasing period are subject to this “project specific materiality” criterion will be considered by the OEB on a case-by-case basis, and if applicable would generally be based on the merged entity, not the individual rate zones.

A distributor in the midst of the Custom IR plan at the time of the transaction that consolidates with an entity operating under a Price Cap IR or an Annual IR Index may only apply for an ICM for investments incremental to its Custom IR plan. The rules that apply to a specific rate-setting method continue to apply even following a consolidation of distributors. To be specific, an ICM would not be available for the rates in the service area for which the Custom IR plan term applies until the term of the Custom IR ends and Price Cap IR applies. Part of a review of any ICM request by the consolidated entity, where one of the distributors was on a Custom IR, would include a test to determine whether the requested amounts for ICM recovery were separate from the amounts that had been included in the distributor’s Custom IR plan.

[26] OEB Letter, *Incremental Capital Modules During Extended Deferred Rebasing Periods*, February 10, 2022

[27] *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, September 18, 2014, p. 17

Materiality thresholds for the ICM will be calculated based on the individual distributors' accounts and not that of the consolidated entity. This policy statement pertains to the ICM materiality threshold formula that is calculated based on depreciation, not the project-specific materiality test based on a comparison of an expenditure to the overall capital budget.

In the ACM Report, the OEB adopted an approach establishing the following three principles with respect to the eligibility of a capital project for ACM/ICM treatment:

- minor expenditures in comparison to the overall capital budget should not be considered eligible for ICM treatment
- a certain degree of project expenditure over and above the threshold calculation is expected to be absorbed within the total capital budget
- the project amount being proposed for recovery should be significant within the context of the distributor's overall capital budget

Any known or reasonably anticipated future ICMs should be documented in a consolidation application. A description of the nature of the project and expected timing should also be provided. The intent of the documentation is to assist stakeholders and the OEB in assessing an applicants' forecasted cost structure (i.e. revenue requirement) analysis provided in a consolidation application. This requirement does not preclude consolidated entities from seeking future ICM funding not identified at the time of the consolidation application. The OEB will consider additional ICMs on the same basis as any ICMs noted in the consolidation application.

If, during its deferred rebasing period, a consolidated utility finds that it has significant capital needs not easily accommodated by an ICM, it should consider rebasing.

The OEB intends to review the ICM/ACM policy applicable to all utilities, including those that are part of a consolidation. That review may result in amendments to the policy.

5.8 Future Rate Structures and Rate Harmonization

Objective 1 of the OEB Act is "to inform consumers and protect their interests with respect to prices and the adequacy, reliability and quality of electricity service." With respect to price, the OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers. The OEB has previously stated that a downward impact on cost structures would tend to decrease rates, whereas an upward impact on cost structures would tend to increase rates. This will occur regardless of what decision is taken concerning rate harmonization at the time of rebasing.[28]

As stated previously, to demonstrate "no harm", applicants must show that there is a reasonable expectation, based on underlying cost structures, that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. Further, it is important for the OEB to consider the impact of a transaction on the cost structure of consolidating entities both now and in the future, particularly if there appear to be significant differences in the size or demographics of consolidating distributors.

While not a requirement, applicants may wish to discuss in their consolidation application any preliminary plans for future rate structures (e.g., anticipated new rate classes, explanation of cost allocation beyond the deferred rebasing period) of the consolidated entity, where such plans are anticipated to impact the applicant's ability to support its claim that "no harm" would result from the approval of a transaction. Consideration and discussion in a consolidation application of how these matters may be addressed at the time of a rebasing application may help assist the OEB in its assessment of the application with respect to the "no harm" test. The OEB recognizes that different transaction types may require different information to support the transaction's claim of "no harm".

Rate Harmonization

The OEB's *Handbook for Utility Rate Applications* states that in the first rebasing application following the consolidation the OEB will scrutinize specific rate-setting aspects of the MAADs transaction, including a rate harmonization plan and/or customer rate classifications post consolidation. This approach will continue. For acquisitions, distributors can propose plans that place acquired customers into an existing rate class or into a new rate class. Regardless of the option adopted, the OEB will assess whether the proposed harmonized rates will reflect the cost to serve the acquired customers, including the anticipated productivity gains resulting from consolidation.[29]

The issue of rate harmonization in the context of a consolidation transaction is better examined at the time of rebasing because this is when the consolidated entity will apply for its combined revenue requirement based on actual circumstances at that time.[30] However, discussion in a consolidation

[28] EB-2013-0196/EB-2013-0187/EB-2013-0198, Decision and Order, p. 16

[29] Handbook for Utility Rate Applications, October 13, 2016, p. 21

[30] A rate harmonization plan can propose the approach and timeline for harmonizing rate classes or provide rationale for why certain rate classes should not be harmonized based on underlying differences in cost structures and drivers.

application of how these matters may be addressed at the time of rebasing may serve as a signal to the OEB, ratepayers, and intervenors that potential issues to be decided at the time of next rebasing have been considered by parties to a transaction.

A statement indicating whether the consolidated utility intends to undertake rate harmonization at the time of rebasing or, if not, an explanation for not doing so, should be included in the consolidation application. Where the utility does intend to harmonize rates, a brief description of the plan should also be provided. This information can be informative to the OEB as to the intentions of the consolidated entity.

The OEB has jurisdiction to address rates-related matters in future proceedings. Rates must be just and reasonable and reflect the cost to serve customers at the time of their determination in a rebasing application. The potential for higher rates for one customer class or rate zone is only one consideration, other benefits of consolidation must also be considered. All relevant factors can be considered by the OEB when rate harmonization plans are filed at the time of rebasing.

The OEB recognizes that information on plans for future rate structures and harmonization is based on forecasts at the time of a consolidation application. Plans will not be considered exhaustive or binding, unless otherwise decided by an OEB panel based on the specific approvals sought, or orders made by the OEB, as part of the proposed consolidation transaction. The intent of the information provided as part of a consolidation application is not to conflate section 78 (i.e., rates) matters, that are appropriately considered at the time of a rebasing application, with section 86 matters.

5.9 Accounting Matters

Disposition Timing

In accordance with the *Electricity Distributors' Deferral and Variance Account Review Initiative* (EDDVAR), Group 1 DVAs are reviewed and subject to disposition if they meet a pre-set threshold during the IRM term.[31] This practice will continue during the deferred rebasing period for utilities that underwent a MAADs transaction. Group 2 accounts require a prudence review and are subject to disposition in a rebasing rate application, which is typically every five years.[32]

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[31] EB-2008-0046, *Report of the OEB on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*, July 31, 2009, p.10

[32] Ibid, pp. 6 & 13

As deferred rebasing periods may be up to ten years, Group 2 account balances for the predecessor utilities that have consolidated may not be disposed for ten or more years. Significant balances may accumulate in these accounts during this period and could lead to intergenerational inequity concerns and/or result in large bill impacts on disposition. Earlier and/or more frequent disposition of Group 2 accounts post-consolidation would address this concern. However, this needs to be balanced with the costs of required prudence reviews in IRM rate applications which contain Group 2 disposition requests.

The OEB sees a benefit in allowing utilities the flexibility to propose disposition of Group 2 DVAs based on their specific circumstances, for example for bill impact concerns. The length of the deferred rebasing period is an important consideration for when Group 2 DVAs should be disposed of, but just as important is how long it has been since the consolidated utilities last rebased. Therefore, if the sum of the deferred rebasing period and period since the last Group 2 disposition is longer than five years, utilities shall provide a plan to submit Group 2 account balances for potential disposition (e.g., at the mid-point of the deferred rebasing period) to mitigate intergenerational inequity. Requests for disposition shall be made if the balances are material at that time set out in the plan. If the sum of the deferred rebasing period and period since the last Group 2 disposition is less than five years, utilities shall have the flexibility of requesting disposition of Group 2 account balances, if warranted and supported, for example in an IRM application.

Tracking of Accounts

Utilities may gain efficiencies by tracking accounts on a consolidated basis, rather than a rate zone basis. Given the nature of the Group 1 accounts and the reliance on data from various systems (e.g., billing system), it is likely practical and efficient for utilities to consolidate the Group 1 accounts for new activities post-closing of the transaction. Therefore, for Group 1 accounts, the OEB encourages utilities to consolidate the accounts as soon as it is practical. Legacy balances should be tracked separately on a rate zone basis for purposes of maintaining cost causality at the time of disposition. However, if there are unique impacts to the utilities’ Group 1 accounts, these circumstances should also be brought forward at the time of the consolidation application.

Legacy Group 2 accounts should also generally be tracked separately on a rate zone basis. Tracking accounts on a rate zone basis will enable those account balances to be disposed to the group of customers that contributed to the balances. However, there could also be some accounts where tracking on a rate zone basis may not be warranted post-MAADs transaction.[33] Therefore, utilities shall be required to provide a proposal in their MAADs applications on which legacy or new Group 2 accounts are to be tracked on a legacy rate zone basis or consolidated basis going forward, with supporting rationale.

Accounting Policy Changes

At the time of the MAADs application, utilities may not have had the opportunity to identify and assess the accounting policy changes required. However, these changes may be material and could result in a refund to, or recovery from, ratepayers. Therefore, in all MAADs applications, a consolidated utility shall establish an account to record the impact of accounting policy changes, effective at the transaction's closing date, unless the predecessor utilities provide sufficient justification as to why such an account is not needed.

The account will serve to symmetrically protect both the consolidated utility and ratepayers. The account shall record the full revenue requirement impact of accounting policy changes.

Materiality shall be a consideration for the continued tracking of amounts in this account so that the cost of maintaining the account does not outweigh the benefit. Once the consolidated utility has completed its assessment of accounting policy changes required, the consolidated utility may propose to close the account in the next IRM application where an audited balance in this account is available, if the impacts of the accounting policy changes are not material. In such cases, no disposition shall be required. Materiality shall be based on the materiality for the predecessor utility whose accounting policies are changed and be disposed of to the customers of the predecessor utility that underwent accounting policy changes.

Although there are precedents where materiality was based on the consolidated utility (rather than the predecessor utility), materiality shall be established based on the predecessor utility, given that it is the predecessor utility that is being specifically impacted by the accounting policy changes.[34] Nevertheless, utilities shall be permitted to propose a different materiality threshold if it better achieves the objective of protecting customer interests.

An accounting order shall be established in the MAADs proceeding, to take effect on the closing date of the MAADs transaction. Consistent with the filing

[33] For example, Account 1522 – Pension & OPEB Forecast Accrual vs. Cash Payment Differential Carrying charges, Account 1508 – Other Regulatory Assets, Sub-account Green Button Initiative Costs may be tracked on a consolidated basis.

[34] EB-2021-0280, Decision and Order, Brantford Power Inc. and Energy + Inc. MAADs, March 17, 2022, p. 17, EB-2022-0006, Decision and Order, Kitchener-Wilmot Hydro Inc. Waterloo North Hydro Inc. MAADs, June 28, 2022. p. 33

requirements for cost of service applications, the accounting order must include a description of the mechanics of the account; examples of general journal entries; and the proposed account duration.[35] The distributor must also file evidence demonstrating how the eligibility criteria of causation, materiality, and prudence have been met.

6. POST-CONSOLIDATION MONITORING AND REPORTING

In November 2022, the Office of the Auditor General of Ontario released its OAGO Audit Report. The OAGO Audit Report included recommendations related to consolidations. In response to these recommendations, the OEB implemented monitoring and reporting requirements for consolidated distributors.[36] As stated previously, the focus of many policies in the MAADs Handbook is electricity distributors, therefore, transmitters should consider the intent of those policies and propose post-consolidation monitoring and reporting.

The OEB as part of its oversight role, collects financial and non-financial information from regulated entities as set out in its *Reporting and Record-keeping Requirements* (RRR). The data collected through RRR ranges from financial and operating to reliability and customer service information. This RRR data is used by the OEB to develop distributor-specific OEB scorecards. Scorecards also provide an opportunity for a distributor to provide a Management Discussion and Analysis of its results. Most RRR information post-consolidation is filed with the OEB on a consolidated basis.

Monitoring of Post-Consolidation Activities During Deferred Rebasing Periods

Consolidation applications include evidence (both qualitative and quantitative) which highlight activities where efficiencies are expected to be achieved, and the savings associated with those efficiencies. This evidence provides an indication of what the consolidated utilities (or acquiring utility) expect could be achieved (based on forecasts). The evidence provided is, in part, what is used by the OEB to reach its decision on a consolidation application and serves as the starting point for the OEB panel considering the first rebasing application post-consolidation. The OEB understands that a utility requires sufficient time to achieve savings and efficiency gains, and these will not begin to be realized until the new entity has begun to operate.

[35] Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, December 15, 2022, pp. 66 & 67

[36] Evaluation of Policy on Utility Consolidations (EB-2023-0188)

The savings are also likely to change over time as the utility begins to better understand its operating needs and environment. Further, transaction and transition costs may be incurred for several years following the completion of the transaction.

For these reasons, in the event of approval of a proposed transaction, a distributor that defers rebasing for more than five years (i.e., six to ten years) must file a mid-term report detailing the progress to date on the steps it has taken toward integration.

At a minimum, the mid-term report shall include the following information, collected on a reasonable efforts basis:

- progress to date on the various activities where efficiencies were expected, and the savings achieved associated with those efficiencies
- a qualitative discussion on enhanced reliability and service quality as a consolidated distributor
- a qualitative discussion on enhanced reliability and service quality on a rate zone basis
- progress towards the recovery of transaction and transition costs
- a discussion on potential obstacles going forward in reaching the consolidated entity's targets as set out in the consolidation application, if any
- an updated revenue requirement analysis as provided in the consolidation application based on information known at the time of the filing of the mid-term report, and a variance analysis to explain material differences to what was filed in the consolidation application.

Distributors must file their mid-term reports with the OEB under the associated filing number of the respective consolidation application proceeding. Reports will be made publicly available. Distributors must also post the mid-term report on their respective website for ease of reference for customers. OEB staff will review mid-term reports internally and may contact distributors for certain clarifications, however, no formal adjudicative steps on the mid-term report are anticipated. OEB staff may identify matters for internal review as part of the OEB's ongoing monitoring and/or reporting processes. The OEB expects this mid-term report will be filed as part of subsequent applications for incremental capital funding (ICMs) or new DVAs.

At the time of the consolidated entity's first rebasing application post-consolidation, the OEB expects the consolidated utility to provide updates to this information based on achieved results, including for any period not covered by the initial mid-term report.

For distributors that elect to defer rebasing for less than five years, a similar report is required, but only at the time of post-consolidation rebasing application (i.e., no mid-term report is required in these circumstances). At a minimum, this end of rebasing report shall include the following:

- achieved efficiencies and savings associated with the various activities where efficiencies were expected (as documented in the consolidation application)
- a qualitative discussion on enhanced reliability and service quality as a consolidated distributor
- a qualitative discussion on enhanced reliability and service quality on a rate zone basis
- total transaction and transition costs, and whether those have been recovered over the term of the deferred rebasing period through the savings achieved
- a discussion on any obstacles encountered since consolidation and how the distributor managed those obstacles. If applicable, a discussion of how obstacles affected the consolidated entity from reaching its targets should also be included

The OEB reminds distributors that at the time of the post-consolidation rebasing application, the OEB expects a utility to provide, on a reasonable efforts basis, an updated version of the revenue requirement analysis provided in the consolidation application (under Price) based on information known at the time of the filing, and a variance analysis to explain material differences.

The OEB expects that following a decision approving a consolidation transaction going forward, consolidated distributors will track the necessary data to fulfil the minimum requirements of the mid-term and rebasing report, as applicable.

The intent of the mid-term report is to inform and increase transparency for the OEB, stakeholders and customers on the progress towards integration. The reports provided at rebasing will help in understanding differences from the forecasts provided at the time of the consolidation application and assist the OEB and other stakeholders in assessing the consolidated distributor's rebasing application.

Reporting on Key Performance Measures During Deferred Rebasing Periods

Service Quality

Service quality metrics post-consolidation are to be filed with the OEB on a consolidated basis per the RRR filing requirements for the first full fiscal year. Section 7 of the OEB's Distribution System Code sets the minimum conditions that a distributor must meet in carrying out its obligations to distribute electricity under its licence with respect to service quality requirements.[37] Each distributor, regardless of consolidation, is expected to meet these targets. This does not preclude independent panels of OEB Commissioners to order the monitoring and/or reporting of service quality metrics by rate zone where such reporting may be necessary on a case-specific basis.

Reliability

Unlike service quality measures, there is currently no industry target for the system reliability measures. The OEB expects either rate zone level or feeder-level reliability reporting post-consolidation. Requirements related to reliability reporting at the rate zone level post-consolidation are detailed in the filing requirements in Schedule 2 of this Handbook.

On January 30, 2024, the OEB implemented new reporting by electricity distributors to improve customer awareness of reliability. Specifically, the OEB established voluntary reporting by distributors on reliability data at the distribution feeder level. The OEB expects this information will be supportive in building customer awareness and understanding of reliability of their distribution service.[38]

Distributors that have not historically reported feeder-level reliability information are encouraged to include such data in the consolidation application for the most recently completed historical years, up to five years, if feeder-level reliability information is available. The rate zone (or multiple zones if applicable) for this feeder-level reliability information should be identified to the extent possible.

Applicants that do not have rate zone reliability information or feeder-level reliability information identified by rate zone, are required to propose a

[37] Distribution System Code, last revised March 27, 2024. The service quality metrics and requirements set out in Section 7 include: Connection of New Services, Appointment Scheduling, Appointments Met, Rescheduling a Missed Appointment, Telephone Accessibility, Telephone Call Abandon Rate, Written Response to Enquiries, Emergency Response, Reconnection Standards, Billing Accuracy.

[38] EB-2021-0307, OEB Letter, Implementing Voluntary Feeder-Level Reliability Reporting, January 30, 2024

different mechanism for reporting reliability for each rate zone during its deferred rebasing period. Reporting requirements should not be a barrier to good system planning that may result in greater integration of systems between rate zones. If system integration affects some of the reliability reporting by rate zone, this should be explained.

Reliability information by rate zone may help assess whether the consolidated utility's ratepayers are experiencing continuous improvement in reliability, or at a minimum, are not experiencing worsening reliability. The OEB recognizes that quantitative reliability data is predicated on historic information that is not necessarily indicative of future results. The OEB is of the view that a distributor should supplement its quantitative reliability reporting and results with qualitative discussions as part of its scorecard reporting,[39] the mid-term report (if applicable), and the post-consolidation rebasing application.

Verification of Adherence to Conditions of Approval and Maintaining Necessary Records

The OEB reminds applicants that it may prescribe certain conditions of consolidation approval on a case-specific basis. The OEB may also require a consolidated entity to maintain certain records during a deferred rebasing period. Independent panels of OEB Commissioners will consider these matters, as needed, on a case-by-case basis. This will include, but is not limited to, an appropriate level and frequency of reporting on these matters during deferred rebasing periods.

[39] Through its Management Discussion and Analysis.

7. INDEX: SCHEDULE 1 – RELEVANT SECTIONS OF THE OEB ACT

Section 86 of the OEB Act

Change in ownership or control of systems

86 (1) No transmitter or distributor, without first obtaining from the Board an order granting leave, shall,

(a) sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety;

(b) sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public; or

(c) amalgamate with any other corporation. 2003, c. 3, s. 55 (1).

Same

(1.1) Subsection (1) does not apply with respect to a disposition of securities of a transmitter or distributor or of a corporation that owns securities in a transmitter or distributor. 2002, c. 1, Sched. B, s. 9 (1).

Acquisition of share control

(2) No person, without first obtaining an order from the Board granting leave, shall,

(a) acquire such number of voting securities of a transmitter or distributor that together with voting securities already held by such person and one or more affiliates or associates of that person, will in the aggregate exceed 10 per cent of the voting securities of the transmitter or distributor; or

(b) acquire control of any corporation that holds, directly or indirectly, more than 10 per cent of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of that corporation. 1998, c. 15, Sched. B, s. 86 (2); 2015, c. 29, s. 15 (1, 2).

8. INDEX: SCHEDULE 2 – FILING REQUIREMENTS FOR CONSOLIDATION APPLICATIONS

ONTARIO ENERGY BOARD

Filing Requirements for Consolidation Applications

JUNE 18, 2024

Ontario Energy Board

Filing Requirements for Consolidation Applications

Table of Contents

Filing Requirements for Consolidation Applications

1. INTRODUCTION

These filing requirements outline relevant information that is necessary for a complete consolidation application. These filing requirements provide the minimum information that applicants must file for a complete consolidation application. However, an applicant is responsible for supporting its application, and should provide any additional information that is necessary to justify the approvals being sought in the application. If circumstances warrant, the OEB may require an applicant to file evidence in addition to that identified in the filing requirements.

1.1 Completeness Review

The filing of a comprehensive application is essential for the development of an accurate Notice of Hearing and for the timely and effective review of an application. Therefore, before the OEB can begin processing the application, it must conduct a preliminary review to determine if the application is complete. The preliminary review determines if the information provided adheres to these Filing Requirements and provides sufficient information to prepare an accurate Notice of Hearing, and if there is any missing information. The OEB typically completes this review within 14 calendar days.

A filing that includes all documentation detailed in these filing requirements will be considered complete for purposes of further processing by the OEB. If the Registrar determines that the application is consistent with these filing requirements, the Registrar will issue a letter notifying the applicant that the OEB has commenced processing the application.

If there are any information gaps in the application, OEB staff will contact the applicants and provide the applicants with an opportunity to file the missing information. The timing required for filing the missing information is determined by the type of information that is missing.

If the missing information adversely affects the OEB's ability to prepare the Notice of Hearing or materially affects the OEB's ability to assess the application, applicants will be required to file the missing information within the 14-day completeness review period. If the information cannot be filed within the 14-day review period, the Registrar will issue an "incomplete letter." This letter will list the information that must be provided before the OEB can commence its review of the application.

If the missing information does not adversely affect the OEB's ability to prepare the Notice of Hearing or materially affect the OEB's ability to assess the application, the OEB may commence the proceeding before the missing information is filed. In such applications, the Registrar will generally issue a letter directing the applicants to file the missing information by the date of the OEB's first procedural order (refer to OEB performance standards for details on the timing of the first procedural order), so that the information is available for the preparation of interrogatories by OEB staff and intervenors. If the information cannot be filed by the noted date and the delay could impact the schedule for the case or the OEB's ability to continue processing the application, the OEB may stop the proceeding and place the application in abeyance until the missing information is filed.

An applicant should only file information that is relevant to the OEB's statutory objectives in relation to electricity. Applicants should refer to the Handbook on the OEB's expectations and approach to reviewing consolidation applications.

1.2 Certification of Evidence

An application filed with the OEB must include a certification by a senior officer of the applicant that the evidence filed is accurate, consistent and complete to the best of their knowledge.

1.3 Updating an Application

When changes or updates to an application or supporting evidence are necessary, applicants must follow the requirements of Rule 11 of the *Rules of Practice and Procedure*. When these changes or updates are contemplated in later stages of a proceeding, updates should only be made if there is a material change to the evidence. In these circumstances, there may be a need for further process to review the updated information and therefore the OEB's planned decision date may shift to accommodate the added process.

1.4 Interrogatories

The OEB advises applicants to consider the clarity, completeness and accuracy of their evidence in order to reduce the need for interrogatories. The purpose of an interrogatory process is to test and/or to further clarify the evidence, not to seek information that should have been provided in the original application. The OEB also advises parties to carefully consider the relevance and materiality of information being sought before requesting it through interrogatories.

Parties must consult Rules 26 and 27 of the OEB's *Rules of Practice and Procedure* (Rules) for additional information on the filing of interrogatories and responses.

1.5 Confidential Information

The OEB relies on complete disclosure of all relevant material to ensure that its decisions are well-informed. To ensure a transparent and accessible review process, applicants should make every effort to file all material publicly and completely. However, the Rules and the *Practice Direction on Confidential Filings* (Practice Direction) allow distributors and other parties to request that certain evidence be treated as confidential. In the event a party wishes to request confidential treatment of certain material, the Practice Direction sets out the requirements for filing the request.

Applicants should be aware that the OEB is required to devote additional resources to the administration, management and adjudication of requests for confidentiality and confidential filings. Applicants must ensure that filings for which they request confidential treatment are both relevant to the proceeding and genuinely in need of confidential treatment. A list of the categories of information that will presumptively be considered confidential is set out in Appendix B of the Practice Direction. To reduce the administrative issues associated with the management of those filings, the OEB expects that distributors will minimize, to the extent possible, requests for confidential information.

1.6 Certification Regarding Personal Information

All parties are reminded of the OEB's rules regarding personal information in any filing they make as part of a proceeding. Parties should consult Rule 9A of the OEB's Rules (and the Practice Direction, as applicable) regarding how to file documents (including interrogatories) containing personal information.

Rule 9A states that “any person filing a document that contains personal information, as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*, of another person who is not a party to the proceeding shall file two versions of the document.” There must be one version of the document that is a redacted version of the document from which the personal information has been deleted or stricken, and a second version of the document that is un-redacted (i.e., that includes the personal information) and should be marked “Confidential—Personal Information”.

The OEB does not expect that personal information would typically need to be filed. However, if the applicant considers it necessary to file personal information as part of its application, the onus is on the applicant to ensure that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A (and the *Practice Direction*, as applicable).

Accordingly, an application filed with the OEB must include a certification by a senior officer of the distributor stating that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A (and the Practice Direction, as applicable).

An applicant is required to provide a similar certification when filing interrogatory responses or other evidence as part of a proceeding.

2. INFORMATION REQUIRED OF APPLICANTS

The OEB expects an application for consolidation to have the following components:

2.1 Exhibit A: The Index

Content	Described In
Exhibit A	
Index	2.1
Exhibit B	
The Application	2.2
Administrative	2.2.1
Description of the Business of the Parties to the Transaction	2.2.2
Description of the Transaction	2.2.3
Impact of transaction on the OEB’s statutory objectives	2.2.4
Rate considerations for consolidation applications	2.2.5
Rate Harmonization	2.2.6
Post-Consolidation Monitoring and Reporting	2.2.7
Accounting Matters	2.2.8
Other	2.2.9

2.2 Exhibit B: The Application

2.2.1 Administrative

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

- Legal name of the applicant or applicants
- Details of the authorized representative of the applicant/s, including the name, phone and fax numbers, and email and delivery addresses
- Legal name of the other party or parties to the transaction, if not an applicant
- Details of the authorized representative of the other party or parties to the transaction, including the name, phone and fax numbers, and email and delivery addresses
- Brief description of the nature of the transaction for which approval of the OEB is sought by the applicant or applicants

2.2.2 Description of the Business of the Parties to the Transaction

This section of the application requires the applicant to provide the following information on the parties to the proposed transaction:

- Describe the business of each of the parties to the proposed transaction, including each of their electricity sector affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity.
- Describe the geographic territory served by each of the parties to the proposed transaction, including each of their affiliates, if applicable, noting whether service area boundaries are contiguous or, if not, the relative distance between service boundaries.
- Describe the customers, including the number of customers in each rate class, served by each of the parties to the proposed transaction.
- Describe the proposed geographic service area of each of the parties after completion of the proposed transaction.
- Provide a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.
- If the proposed transaction involves the consolidation of two or more distributors, please indicate the maximum peak load (kW) for each distributor’s service area that is used to calculate the distributor's maximum “cumulative generation capacity from net metered

generators". The OEB will, in the absence of exceptional circumstances, add together the kW peak load from each distributor and assign the sum to the new or remaining utility. Applicants must indicate if there are any special circumstances that may warrant the OEB using a different methodology to determine the net metering threshold for the new or remaining utility.

2.2.3 Description of the Proposed Transaction

This section of the application requires the applicant to provide the following:

- Provide a detailed description of the proposed transaction.
- Provide a clear statement on the leave being sought by the applicant, referencing the particular section or sections of the Ontario Energy Board Act, 1998. This also includes all approvals being sought that are necessary for the proposed consolidation. Examples include, without limitation, licence amendments and cancellations; issuance of new licences; accounting orders (to establish any new deferral and variance accounts); and code exemptions, if applicable.
- Provide details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.
- Provide all final legal documents to be used to implement the proposed transaction.
- Provide a copy of appropriate resolutions by parties such as parent companies, municipal council/s, or any other entities that are required to approve a proposed transaction confirming that all these parties have approved the proposed transaction.

2.2.4 Impact of the Proposed Transaction

In reviewing an application, the OEB will apply the "no harm" test as outlined in the Handbook. Applicants are required to provide the following evidence to demonstrate the impact of the proposed transaction with respect to the OEB's first two statutory objectives.

Objective 1 – Protect consumers with respect to prices and the adequacy, reliability and quality of electricity service

- Indicate the impact the proposed transaction will have on all consumers with respect to prices and the adequacy, reliability and quality of electricity service. The impacts may include but not be limited to operational considerations and aspects of customer service.
- Provide a year-over-year comparative forecast revenue requirement analysis for the proposed transaction, comparing the costs of the utilities post-transaction on a consolidated basis and the costs of the utilities in the absence of the transaction (status quo scenarios). The analysis should cover the duration of the deferred rebasing period, up to and including the post-consolidation rebasing year. For the post-consolidation rebasing year, the utility should include the forecast net savings that would flow to ratepayers at that time.
    - Document assumptions about inflation, growth and productivity adjustments
    - Under the status quo scenarios, provide what would be normal expected cost of service revenue requirement adjustments at normally scheduled rebasing years during the deferred rebasing period.[40]
    - Document and describe any assumptions made related to the impact of an evolving energy sector, and associated impacts on cost structures
    - Document any known or reasonably anticipated future ICMs in the application both in terms of timing and in quanta (i.e., revenue requirement). Any known or reasonably anticipated ICMs should be reflected in both the consolidated and stand-alone scenarios, or otherwise provide explanation.

  Applicants can refer to Appendix A as an example of a revenue requirement analysis for a merger between two utilities on Price Cap IR which elect a ten-year deferred rebasing period. Applicants should adapt the analysis to suit their circumstances and incorporate their assumptions.

- Provide a statement confirming that at the time of the post-consolidation rebasing application, the consolidated entity will produce an updated analysis comparing the revenue requirement (under both the consolidated scenario and the status quo) but based on

[40] Generally, forecasts of these hypothetical rebasing applications would be based on past experience, but also informed by information on current inflation, interest rate and market returns, and cost trends of the utility.

information available on a reasonable efforts basis. Further, provide a statement confirming that this will be supplemented with a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.[41]

- Provide a comparison of the OM&A cost per customer per year between the consolidating utilities. The information should include the latest actual OM&A per customer for each utility and the forecast OM&A per customer for each year of the elected deferred rebasing period (including the post-consolidation rebasing year) for each utility and on a consolidated basis.
- Confirm whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.
- Describe how the distribution or transmission systems within the service areas will be operated.

Objective 2 – Promote economic efficiency and cost effectiveness and to facilitate the maintenance of a financially viable electricity industry

- Indicate the impact that the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity), identifying the various aspects of utility operations where the applicant expects sustained operational efficiencies (both quantitative and qualitative) (e.g., expected OM&A and capital efficiencies).
- Identify all incremental costs that the parties to the proposed transaction expect to incur which may include incremental transaction costs (e.g. legal, regulatory), incremental transition costs (e.g. employee severances), and incremental on-going costs (e.g. purchase and maintenance of new IT systems). Explain how the consolidated entity intends to finance these costs.
- Provide a valuation of any assets or shares that will be transferred in the proposed transaction. Describe how this value was determined.
- If the price paid as part of the proposed transaction is more than the book value of the assets of the selling utility, provide details as to why this price will not have an adverse effect on the financial viability of the acquiring utility.

[41] Documentation on differences in actual inflation and stretch factors, growth, unanticipated needed investments, and other matters as required, from what was forecast at the time of the MAADs, or details of additional actual costs (e.g., ICMs or Z-factors) may suffice.

- Provide details of the financing of the proposed transaction.
- Provide financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.
- Provide pro forma financial statements for the consolidated entity for the first full year following the completion of the proposed transaction, including the assumptions/explanations used in the pro forma financials, as well as the methodology used to forecast amounts. If pro forma financials are not available, an explanation should be provided.

2.2.5 Rate considerations for consolidation applications

Applicants are required to provide the information with respect to the following rate making considerations relating to consolidation:

- Indicate a specific deferred rate rebasing period that has been chosen.
- Identify the rate year and effective date for rebased rates at the end of the elected deferred rebasing period.
- For deferred rebasing periods greater than five years:
    - Confirm that the ESM will be as required by the 2015 Report and the Handbook.
    - If the applicant's proposed ESM is different from the ESM set out in the 2015 Report, the applicant must provide evidence to demonstrate that the ESM better achieves the objective of protecting customer interests during the deferred rebasing period.
    - Calculate a deemed ROE for the purposes of the ESM calculations for the consolidated entity, by weighting the approved ROEs for each utility from their respective last rebasing applications by the deemed equity component of the rate base of each utility in their last rebasing applications.
    - For the ESM account, provide an accounting order, to take effect on the closing date of the MAADs transaction (subject to the calendar year data considerations discussed above), including a description of the mechanics of the account; examples of general journal entries; and the proposed account duration.[42]

[42] The accounting order shall be consistent with the Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, December 15, 2022, p. 67

- If applicable, for a proposed consolidation between one consolidated utility in a deferred rebasing period (as a result of a previously approved consolidation) merging or acquiring another utility not in a deferred rebasing period:
    - Confirm the remaining deferral period for the previously consolidated entity.
    - Identify the elected number of years for the deferred rebasing period (maximum 10) for the utility being consolidated into the previously consolidated entity and identify the rate year for which rebased rates would be effective (in other words, for the most recent utility being acquired or merged into the previously consolidated entity).
    - Identify the proposed timing for rebasing of the new consolidated entity.
    - If the applicants seek to extend the elected deferred rebasing period of the previously consolidated entity (if the originally elected period was less than ten years), the onus will be on the applicant(s) to justify the need for, and benefits of, any requested extension to the current deferral period.

The last bullet point above allows the OEB to rationalize successive MAADs transactions involving one utility deferring rebasing for a longer period than originally contemplated (but only if the original deferral period elected was less than ten years) and assesses the impacts of potentially retaining savings on a continuing basis for shareholders rather than sharing those savings with ratepayers. It also commits the utility to explaining why further delays in reviews of costs, operations, and rates of a consolidated utility and its predecessor utilities by the OEB is in the public interest.

2.2.6 Rate Harmonization

Provide a statement indicating whether the consolidated utility intends to undertake rate harmonization at the time of rebasing or, if not, an explanation for not doing so. Where the utility does intend to harmonize rates, a brief description of the plan should be provided.

2.2.7 Post-Consolidation Monitoring and Reporting

Post-Consolidation Reports

For applicants that defer rebasing for more than five years:

- A statement confirming that a mid-term report will be filed containing the required components as set out in the Post-Consolidation Monitoring and Reporting section of the Handbook.
- A statement confirming that in the first rebasing application, updates to this information will be provided including for any period not covered by the initial mid-term report.

For applicants that defer rebasing for less than five years:

- A statement confirming that in the first rebasing application, a report containing the components as set out in the Post-Consolidation Monitoring and Reporting section of the Handbook will be provided.

Reliability Reporting During Deferred Rebasing Periods

- For applicants that have historically filed feeder level reliability information leading up to the consolidation application or for applicants that have not historically reported feeder-level reliability information, but will do so going forward:
    - Provide a listing of feeder reliability by rate zone (i.e. for the predecessor utilities) for the most recently completed historical years available, up to five years.
    - Confirm that going forward, the consolidated utility will continue report feeder-level reliability information and identify the rate zone for each feeder during the deferred rebasing period.
- For applicants that cannot provide feeder-level reliability information for at least one (or any) rate zone as part of the consolidation application and going forward:
    - Propose a different mechanism to report reliability by rate zone during the deferral period.

2.2.8 Accounting Matters

- For Group 1 accounts, the OEB encourages utilities to consolidate the accounts as soon as it is practical. However, if there are unique impacts to the utilities' Group 1 accounts, these circumstances should also be brought forward at the time of the consolidation application.
- If the sum of the deferred rebasing period and period since the last Group 2 disposition is longer than five years, provide a plan to submit Group 2 account balances for potential disposition (e.g., at the mid-point of the deferred rebasing period) to mitigate intergenerational inequity.
- Provide a proposal on which legacy or new Group 2 accounts are to be tracked on a legacy rate zone basis or consolidated basis going forward, with supporting rationale.
- For the Accounting Policy Changes account, provide an accounting order, to take effect on the closing date of the MAADs transaction, including a description of the mechanics of the account; examples of general journal entries; the proposed account duration; and how the eligibility criteria of causation, materiality, and prudence have been met.[43]
- In the alternative, provide sufficient justification as to why the Accounting Policy Changes account is not needed.

2.2.9 Other

Applicants have, in previous consolidation applications, made additional requests to the OEB which have formed part of the OEB's determination of a consolidation application. Examples include:

a) Implementation of new or the extension of existing rate riders
b) Transfer of rate order

Applicants are required to provide justification for these types of requests and for any other requests for which a determination is being sought from the OEB as part of a consolidation application.

[43] The accounting order shall be consistent with the Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications, Chapter 2, Cost of Service, December 15, 2022, p. 66 & 67

3. APPENDIX A

Example of Cost Structure Analysis

Assumptions

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Customer Growth (%) – Utility 1											
Customer Growth (%) – Utility 1											
Inflation (%)											
Stretch Factor on a Standalone Basis (%) – Utility 1											
Stretch Factor on a Standalone Basis (%) – Utility 2											
Stretch Factor on a Consolidated Basis (%) – Rate Zone 1											
Stretch Factor on a Consolidated Basis (%) – Rate Zone 2											
Other											

Revenue Requirement – Standalone

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
	Budget	**IRM**	**IRM**	**COS**	**IRM**	**IRM**	**IRM**	**IRM**	**COS**	**IRM**	**IRM**
Utility 1											
	Budget	**IRM**	**IRM**	**COS**	**IRM**	**IRM**	**IRM**	**IRM**	**COS**	**IRM**	**IRM**
Utility 2											
Standalone Total – Utility 1 + 2											

Note: tables have been shown with an example of the yearly rate application types for each predecessor utilities. Applicants are to reflect their particular rate application types per year for each predecessor utility.

Revenue Requirement – Merged

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
	Budget	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**COS or CIR**
Rate Zone 1											
	Budget	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**IRM**	**COS or CIR**
Rate Zone 2											
Merged Total											

Note: IRM could be Annual IR. See Table 1 of Handbook.