Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

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Table of Contents

1 INTRODUCTION 1

2 ELECTRICITY DISTRIBUTION RATE-SETTING 7
2.1 Background 7
2.2 Evolving the Board's Approach to Rate-setting 7
2.2.1 Description of the Three Rate-setting Methods 14
2.3 Decoupling 23
2.4 Rate Mitigation 23
2.4.1 Mitigation Policies under the Renewed Regulatory Framework 24
2.5 Implementation 25

3 DISTRIBUTION INFRASTRUCTURE INVESTMENT PLANNING 27
3.1 An Integrated Approach to Distribution Network Planning 27
3.1.1 Planning as the Foundation for Rate-Setting 27
3.1.2 The Board's expectations for asset management and investment planning 35
3.1.3 Tools and methods to support proposed investments 36
3.2 Regional Infrastructure Planning 38
3.2.1 Background 38
3.2.2 Integration of Regional Considerations 38
3.2.3 Facilitating the Implementation of Regional Infrastructure Planning through Amendment of Board Codes 41
3.3 Development of the Smart Grid 46
3.3.1 Background 46
3.3.2 Smart Grid Planning and Innovation 47
3.3.3 Treatment of Smart Grid Investments for Rate-setting 48
3.3.4 Demarcation of Utility Role: "Behind the Meter" Activities 48
3.3.5 Other Issues 50
3.4 Implementation 50
3.4.1 Distribution network investment planning 52
3.4.2 Facilitating effective regional infrastructure planning 52
3.4.3 Facilitating the implementation of regional infrastructure planning 53
3.4.4 Smart grid guidance 53

4 PERFORMANCE MEASUREMENT AND CONTINUOUS IMPROVEMENT 55
4.1 Monitoring Distributor Performance 55
4.2 The Role of Benchmarking 59
4.3 Regulatory Mechanisms 60
4.4 Implementation 62
4.4.1 Issues to be addressed in relation to standards, measures and regulatory mechanisms 63
4.4.2 Issues to be addressed in relation to benchmarking 65

5 IMPLEMENTATION AND TRANSITION 67
5.1 Implementation 67
5.2 Transition 68

APPENDIX A: SUMMARY OF CONSULTATION ACTIVITIES TO DATE I

APPENDIX B: SUMMARY OF PLANNED CONSULTATION ACTIVITIES VII

1 Introduction

The Ontario Energy Board regulates the rates of the 77 local electricity distributors that operate Ontario's local electricity delivery networks. These networks are essential to the seamless delivery of electricity from generators to end users. The cost of distributing electricity represents approximately 20% to 25% of the total electricity bill. Revenues collected from customers contribute to the ongoing operation and maintenance of the system as well as its expansion and modernization. Ontario's electricity distributors represent significant capital investments, with total assets of approximately $17 billion, and new investment of $1.9 billion in 2011. And while all distributors perform a similar service, their investment needs vary over time. Ontario's energy sector is evolving, as are the expectations of customers and the obligations placed on distributors as a result. The Board believes that our approach to regulation needs to evolve along with the sector.

The Board needs to regulate the industry in a way that serves present and future customers, and that better aligns the interests of customers and distributors while continuing to support the achievement of public policy objectives, and that places a greater focus on delivering value for money. A number of factors have prompted the Board's work on a renewed regulatory framework: government policy, aging infrastructure, customer concerns regarding rate increases, the increased maturity of the industry, and a need to harmonize and consolidate Board policies related to planning and rate setting.

The Board's renewed regulatory framework for electricity is designed to support the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. Through taking a longer term view, the new framework will provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price. The performance-based approach described in this Report is an important step in the continued evolution of electricity regulation in Ontario.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

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

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

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

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

The Board has developed a set of related policies to facilitate the achievement of these performance outcomes. The Board remains committed to continuous improvement within the electricity sector, The Board's policies for setting distributor rates as outlined below are supported by fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations.

The following are the three main policies:

- Rate-setting: There will be three rate-setting methods: 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. Rate-setting is discussed in Chapter 2.

- Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. Planning is discussed in Chapter 3.

- Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. Performance measures and monitoring are discussed in Chapter 4.

In developing the policies in this Report, the Board has been guided by its objectives in relation to electricity, as listed in section 1(1) of the *Ontario Energy Board Act, 1998* (the “OEB Act”). These objectives are:

1. To protect the interests of consumers 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 the implementation of a smart grid in Ontario.

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

The first two objectives, the protection of consumer interests and the promotion of economic efficiency and cost effectiveness within a financially viable industry, are the foundation of the renewed regulatory framework. These objectives are reflected in the outcomes set out above and are the main principles of the distribution rate-setting and performance measurement policies. They are also key considerations in the emphasis on pacing and prioritization of capital investment embodied in the planning policy.

The remaining three objectives of the Board in relation to electricity are reflected in the policies regarding infrastructure planning. Steps toward achieving these public policy objectives in respect of conservation and demand management, smart grid implementation and the expansion or reinforcement of the system to facilitate renewable generation are incorporated into the planning policy.

With the exception of regional infrastructure planning and smart grid, which apply to both distributors and transmitters, the policies set out in this Report apply to distributors only at this time. In due course, the Board will provide further guidance regarding how the policies in this Report may be applied to transmitters.

Policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year. Specifically, the new instruments for all three rate setting methods will be available to those seeking to rebase rates effective May 1, 2014.

The Board is committed to monitoring and evaluating the effectiveness of its policies. It will do so by identifying desired policy outcomes and requiring annual monitoring and reporting to measure success against those outcomes. The Board will develop the policy evaluation framework for the renewed regulatory framework after further work has been completed in relation to the distributor performance “scorecard”. More information on this policy evaluation framework will be provided later.

2 Electricity Distribution Rate-Setting

2.1 Background

The Board has employed incentive regulation ("IR"), including formula-based and cost-based rate-setting, since it began regulating the rates of electricity distributors in 2001. Under its current approach to IR, the Board uses one year forecasted cost and revenue information to determine a base revenue requirement and the "base" rates that are set to recover that revenue requirement. In subsequent years, those base rates are adjusted annually according to a Board-approved formula that includes components for inflation and the Board's expectations of efficiency and productivity gains.

The Board's current IR plan for distributors ("3rd Generation IR") was established in 2008.[1] The core of the 3rd Generation IR plan is an "inflation minus X-factor" price-cap form of rate adjustment mechanism, which is intended to incent innovation and efficiency. The X-factors for individual distributors consist of an empirically derived industry productivity trend and differentiated stretch factors. Benchmarking, based only on operations, maintenance and administration ("OM&A") cost data, provides the basis for the annual assignment of stretch factors to distributors.

2.2 Evolving the Board's Approach to Rate-setting

As noted in Chapter 1, the maintenance and modernization of electricity distribution infrastructure will continue to exert cost pressures on customers. The Board's approach to rate-setting must continue to support a sustainable, financially viable and reliable

[1] The Board's 3rd Generation IR policy approach is set out in the "Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" dated July 14, 2008. A Supplemental Report of the Board setting out the Board's determination of the values for the productivity factor, the stretch factors, and the capital module materiality threshold for use in the 3rd Generation IR plan was issued on September 17, 2008; and on January 29, 2009, the Board issued its "Addendum to the Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors" which sets out the Board's determination on the model it would use to assign stretch factors to distributors.

electricity system. It must do so in a manner that is responsive to customers' concerns about affordability, by promoting increased efficiency which in turn can lower costs and provide for more predictable rates. It must also do so in a manner that better accommodates differing circumstances of distributors (for example, with respect to customer expectations, asset profile and investment needs) and facilitates the cost-effective and efficient achievement of expected performance outcomes. Finally, the rate regime must also recognize the inter-connected nature of the electricity system in Ontario, promote ongoing productivity improvements, encourage innovation, and support efficient regulation.

As part of the renewed regulatory framework consultation process, the Board issued a "straw man" model regulatory framework that identified at a high level certain potential changes to the Board's approach to rate-setting, including the pre-approval of multi-year plans, a focus on reliability, targeted rate-setting (treating OM&A and capital separately) to increase the pursuit of operating efficiencies, and greater flexibility in respect of the period between cost of service reviews.

Stakeholder Views

Stakeholder views on whether rate-setting should be targeted or comprehensive diverged significantly. Some distributors expressed strong support for targeted rate-setting. Those opposed argued that the capital and operating expenditures are too inter-related to be easily severed. Further, these stakeholders expressed concern that severing the two could create bias for one over the other resulting in sub-optimal investment, particularly in the absence of least-cost planning processes.

Stakeholder comment was generally in support of flexibility in the length of an IR term. Some stakeholders representing different business groups noted that aligning the IR plan term to match a 5-year planning horizon would be a sensible approach.

With respect to the current 3rd Generation IR plan, many stakeholders supported revising the inflation and productivity indices to better reflect circumstances faced by distributors in Ontario. Regarding the ICM some argued it is too restrictive while another commented it is sufficient because it is meant to be used in extraordinary circumstances rather than on a regular basis.

Many stakeholders commented on the need for flexibility in rate-setting to accommodate distributor differences, especially with respect to different capital spending needs. A menu approach – one that could include more than one type of rate-setting method (e.g., a simple index method and a multi-year approval-type method) – was identified by a few stakeholders as the preferred means of providing such flexibility. It was suggested that a distributor’s ability to access certain rate-setting options should be linked to the distributor’s benchmarked performance ranking.

Off-ramps and earnings sharing mechanisms were identified by some as necessary ratepayer protection mechanisms, particularly in longer term IR rate-setting.

The Board’s Conclusions

The Board continues to support a comprehensive approach to rate-setting, recognizing the interrelationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board’s implementation of an outcome-based framework.

Three alternative rate-setting methods will be available to distributors.

Each distributor may select the rate-setting method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. This will provide greater flexibility to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant and may include “lumpy” investments, and others of which have capital needs that are expected to be comparatively stable over a prolonged period of time.

The Board remains committed to the principles enunciated in its 3rd Generation IR report, and all three rate-setting methods are based on a multi-year IR mechanism. Each rate method will be supported by: the fundamental principles of good asset management; coordinated, longer-term optimized planning; a common set of performance expectations; and benchmarking. Rate applications will be supported by a five-year capital plan that includes consideration of regional infrastructure planning.

The Board believes that this more flexible approach to rate-setting will:

- enhance predictability necessary to facilitate planning and decision-making by customers and distributors;
- better align rate-setting with distributor planning horizons;
- facilitate the cost-effective and efficient implementation of distributor multi-year plans that have been developed to achieve the outcomes for customer service and cost performance; and
- help to manage the pace of rate increases for customers.

The Board’s rate-setting policy in this Report represents a further development of the approach adopted by the Board when it first established performance based regulation (“PBR”) for electricity distributors in its January 18, 2000 Decision with Reasons:

> … PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-

> minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board."[2]

Going into PBR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for ratebase to be re-calibrated annually.

In implementing the new approach to rate-setting, the Board will use a rigorous performance reporting and monitoring process to ensure that, while distributors are responding to performance incentives, customer interests are being protected. As described in Chapter 4, a scorecard will be developed to measure distributor performance on four performance outcomes: customer focus, operational effectiveness, public policy responsiveness, and financial performance. One measure that will continue to be considered by the Board is annual earnings. The Board's policy in relation to the off-ramp, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, continues to be appropriate. Each rate-setting method will include a trigger mechanism with an annual return on equity ("ROE") dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. The Board will continue to require consistent, meaningful and timely reporting to enable the Board to monitor utility performance and determine if the expected outcomes are being achieved. This approach will, in turn, allow the Board 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. Customer

[2] Paragraph 2.0.14, p. 13, RP-1999-0034 Decision with Reasons, January 18, 2000

interests will also remain protected through regulatory processes that will continue to be open and transparent.

To ensure that the benefits from greater efficiency are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X factor.

With the introduction of these three rate-setting methods, the Board will review its existing rate-related policies for continued efficacy and to confirm whether and to what extent they can be integrated into any one or more of these rate-setting methods. The Board currently expects that existing policies will remain in place to support rate-setting in the future.

The key elements of the three rate-setting methods are set out in the following Table, and are described in greater detail below.

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

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

The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting ("4th Generation IR"), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.

Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index ("Annual IR Index").

The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.

2.2.1 Description of the Three Rate-setting Methods

4th Generation IR

Building on the current 3rd Generation IR, the 4th Generation IR method includes certain enhancements to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. The 4th Generation IR method will be appropriate for distributors that anticipate that some incremental investment needs may arise during the term of the rate method.

Under this method, rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4th generation price cap index formula. The Board will retain a comprehensive price cap form of adjustment mechanism. The Board believes that the price cap approach, like that used in the Board's earlier IR plans, continues to be appropriate for most distributors.

The Board has determined that the term for 4th Generation IR will be five years (rebasing plus 4 years). This longer term will better align rate-setting and distributor planning, strengthen efficiency incentives, support innovation and help manage the pace of rate increases for customers.

A distributor on 4th Generation IR may request early termination and seek to have its rates rebased if it meets the Board's criteria for early rebasing.[3] As noted previously, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

As with current 3rd Generation IR, the allowed rate of change in the price of regulated services will be adjusted by the growth in an inflation factor minus an X-factor.

The Inflation Factor

Under price cap mechanisms, changes in price indices are reflected in allowed changes in output prices for regulated services (i.e., indices escalate the allowed prices).

The inflation factor could be established in one of two ways: either an industry-specific price index ("IPI") designed to track the inflation of the industry inputs, or a macroeconomic index. The Board has consulted with stakeholders on several occasions over the last ten years on inflation factors. The merits of, and concerns

[3] In keeping with the Board's approach as set out in its April 20, 2010 letter, a distributor that seeks to have its rates rebased earlier than scheduled must justify, in its cost of service application, why early rebasing is required and why and how the distributor cannot adequately manage its resources and financial needs during the remainder of the 4th Generation Plan term.

associated with, an IPI were summarized by the Board in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> …an IPI would track industry input price fluctuations better than an economy-wide measure. It may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. However, the Board observes that the implementation of the IPI methodology that was used in 1st Generation IR with recent data produces a very volatile index, as shown in the illustrative example presented in the [Staff] Discussion Paper. Such volatility could be harmful to both ratepayers and distributor shareholders, if reflected in rates. The Board believes that further research is required on the methodological approach to address such volatility and to ensure that the chosen sub-indices appropriately track the inflation faced by the industry.[4]

The Board has concluded it is now appropriate to adopt a more industry specific inflation factor for 4th Generation IR. Concerns regarding volatility will be mitigated by the methodology selected by the Board. The Board also will be guided by the following:

- the inflation factor must be constructed and updated using data that is readily available from public and objective sources such as, for example, Statistics Canada, the Bank of Canada, and Human Resources and Social Development Canada;
- to the extent practicable, the component of the inflation factor designed to adjust for inflation in non-labour prices should be indexed by Ontario distribution industry-specific indices; and
- the component of the inflation factor designed to adjust for inflation in labour prices will be indexed by an appropriate generic and off-the-shelf labour price index (i.e., not distribution industry-specific)

[4] At pp. 10-11.

X Factors

The Board described the components of an X-factor in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors as follows:

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.
>
> The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that distributors are expected to achieve under IR and is a common feature of IR plans. These expected productivity gains can vary by distributor and depend on the efficiency of a given distributor at the outset of the IR plan. Stretch factors are generally lower for distributors that are relatively more efficient.[5]

The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.

All distributors will be subject to the same productivity factor that will be set in advance for the purposes of the 4th Generation method. The Board will continue to use an index-based approach for the derivation of an industry productivity trend to form the basis for the productivity factor. The Board will update the industry productivity factor every five years (e.g., the update after 2014 would be in 2019).

The Board's approach in relation to the use and assignment of stretch factors under 3rd Generation IR will continue under 4th Generation IR. Distributors will continue to be assigned annually to one of three efficiency cohorts. The Board will make these

[5] At page 12.

assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.

Capital Spending

There will not be an ICM in the Custom IR method. Under this method, distributors will be expected to operate under their Board-determined multi-year rates.

Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

Annual IR Index

The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor.

Distributors, who apply under this method for 2014 rates or later, must have had a cost of service hearing in 2008 or later. The Board also expects that a distributor applying under this method will not be exceeding its approved annual ROE by more than 300 basis points.

Like other rate setting methods, a rate application under the Annual IR Index must also include a five year forecast of capital investments, except as noted in section 5.2 of this Report dealing with transitional issues. However, as indicated in Chapter 3, the scope and level of detail required in this plan will be proportional to the scope and magnitude of the proposed investments. As with all the rate-setting methods, annual reporting will be required from distributors on the Annual IR Index.

The prudence review associated with the disposition of Group 2 variance and deferral accounts makes their disposition generally incompatible with the design of the Annual IR Index. For that reason, a distributor that applies to have its rates set under the Annual IR Index is expected to limit requests for disposition of deferral and variance accounts to Group 1 accounts while it is on the Annual IR Index. If a distributor is seeking the disposition of any Group 2 accounts, that review and disposition will need to be the subject of a separate application.

Given the nature of the rate adjustments under this method, the Board does not believe that it is necessary to establish a fixed term for it, and a distributor whose rates have been set under it may apply to have its rates rebased and set under a different method at any time. As noted previously, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

Under the Annual IR Index rates will be adjusted annually by the growth in an inflation factor minus an X-factor.

Inflation Factor

The inflation factor determined for use in 4th Generation IR will also be used in the Annual IR Index.

X-Factor

Under the Annual IR Index, the Board will index rates by a percentage of the inflation factor so that annual adjustments under the Annual IR Index include recognition of expected productivity gains over time. This is particularly important given that there is no fixed term for this plan. To achieve this, the Board has determined that the X-factor for the Annual IR Index will be set after the Board's determination of the X-factor values for 4th Generation IR. The X-factor for the Annual IR Index will be the same as the highest X-factor set for 4th Generation IR in 2014, as updated every five years. This will ensure that the resultant rate adjustment under the Annual IR Index is equal to the lowest rate adjustment under 4th Generation IR. All distributors on the Annual IR Index will be subject to the same X-factor. When updated by the Board, the new X-factor will automatically be applied to all distributors that are then on the Annual IR Index.

Capital Spending

There will be no ICM in the Annual IR Index. The method presumes a largely steady-state or sustainment mode of operation by the distributor.

2.3 Decoupling

In 2010 the Board initiated a consultation process in relation to revenue decoupling mechanisms. The focus of that consultation was to examine the extent of revenue erosion due to, among other things, energy conservation efforts. The Board issued a consultant's report for stakeholder comment. That report contained a review of revenue decoupling mechanisms implemented in other jurisdictions and proposed options for consideration in Ontario.[6]

The Board indicated, when it initiated the renewed regulatory framework project in 2010, that the revenue decoupling consultation would proceed once there was substantial completion of the renewed regulatory framework policy initiative. The Board is of the view that it is now appropriate to resume the revenue decoupling initiative. Information regarding this initiative will be provided in due course.

2.4 Rate Mitigation

Rate mitigation has been a policy of the Board since 2000. At that time, the Board established a requirement that distributors *consider* mitigation where total bill increases for any customer class exceed 10%.[7] Since only consideration and not implementation of mitigation is required, this percentage is referred to as a "soft" threshold. The most recent articulation of the Board's mitigation policy confirmed the continuation of the "soft" 10% threshold for the filing of mitigation plans and provides guidance to distributors on preparing those plans.[8] In its mitigation plan a distributor may propose any, or no, mitigation mechanism as may be suitable in a particular circumstance.

[6] Lowry, Mark Newton, Ph.D., et al., Pacific Economics Group Research LLC. Review of Distribution Revenue Decoupling Mechanisms. March 19, 2010.
[7] January 18, 2000 Decision with Reasons in a proceeding to determine certain matters relating to the proposed Electricity Distribution Rate Handbook (RP-1999-0034).
[8] Report of the Board May 11, 2005 – 2006 Electricity Distribution Rate Handbook, p. 90.

2.4.1 Mitigation Policies under the Renewed Regulatory Framework

An objective for the development of a renewed regulatory framework is to ensure that distributors are encouraged to manage the prioritization and pace of network investments having regard to the total bill impact on customers. This prompted the Board to include the re-examination of its rate mitigation policy as part of the renewed regulatory framework consultation.

Stakeholder Views

There was broad support for the idea that distributors should consider mitigation when engaged in planning, ensuring that capital and OM&A expenditures are paced and prioritized in a manner such that costs are smoothed and minimized over the long term. Ensuring that the Board's approach to rate setting is designed such that rate increases are more gradual also received support from stakeholders. Conflicting views were expressed about whether the Board should consider total bill increases for rate mitigation purposes. A hybrid approach was proposed under which distributors would be required to consider anticipated total bill increases when planning investments. However, mitigation after the revenue requirement has been determined would only apply in relation to anticipated increases in distribution rates.

Stakeholder's comments reinforced that mitigation may not necessarily be appropriate in all circumstances. Some argued that the threshold should be "soft", thereby providing more flexibility in determining when the filing of a mitigation proposal is required. Other stakeholders, however, supported a firm and consistently-applied threshold, arguing that this will achieve greater predictability for both ratepayers (in relation to their electricity costs) and distributors (in relation to the regulatory process).

There was agreement among most stakeholders that, regardless of methodology, an empirical threshold should be developed. Proposals for a methodology on which to base the threshold include: a customer 'willingness to pay' survey or an 'economic tolerance' study; a factor of an inflation index such as the Consumer Price Index; and the establishment of criteria rather than relying on a specific figure.

In general, stakeholders were comfortable with continued use of conventional mechanisms but believed that alternative mechanisms should be further explored.

The Board's Conclusions

The Board has concluded that it will maintain its current policy with respect to rate mitigation. The implementation of the renewed regulatory framework should make the need for mitigation of large rate increases less likely as controls to address cost increases are integrated into the planning and rate-setting processes, and each distributor will be able to choose the rate-setting approach that best suits its particular investment profile. The Board will expect distributors to consider total bill increases when they engage in planning, an exercise that will be facilitated under the integrated approach to network planning described in Chapter 3, and to demonstrate to the extent possible the responsiveness of their planned capital and OM&A expenditures to the need for reasonably stable and affordable rates for customers. The Board is therefore of the view that changes to its rate mitigation policy are not necessary at this time. Once the Board and stakeholders have gained experience with the new rate-setting methods, the Board may revisit this issue if the need arises.

The Board further concludes that it is not necessary at this time to limit the mitigation mechanisms that distributors may want to propose. The Board will continue to evaluate proposed mechanisms on a case-by-case basis.

2.5 Implementation

Issues related to the inflation and productivity adjustment mechanisms have been explored in several different consultations over the last ten years. The Board has benefited from those consultations and has gained significant experience applying the results of those consultations. Consequently, the Board is of the view that the most expeditious way to reach a determination on these issues is through a Board-led stakeholder conference followed by written submissions. To inform the conference, new inflation, productivity and stretch factors, will be developed in consultation with stakeholders as part of the performance, benchmarking and rate adjustment indices work described in Chapter 4. The Board expects to issue its determinations on these issues in mid-2013.

Product	**Planned issuance**	**Process**
Determination of inflation & productivity factors, and stretch factors	June 2013	Stakeholder conference followed by written submissions
Revised Filing Requirements for cost of service rate applications (and IR adjustment if necessary)	June 2013	Consolidation of work from Network Infrastructure Investment Planning and Performance Measurement
Board determination on stretch factor assignments for 4th Generation IR	July 2013	As per current process

3 Distribution Infrastructure Investment Planning

Under the renewed regulatory framework, good planning is necessary to ensure that the Board's outcomes as set out in Chapter 1 are being achieved. The Board's approach to rate-setting described in Chapter 2 also depends on effective planning by distributors. The Board needs evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget. Distributor plans must therefore demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate consultation with customers, municipalities and neighbouring distributors and transmitters where applicable.

3.1 An Integrated Approach to Distribution Network Planning

3.1.1 Planning as the Foundation for Rate-Setting

A number of Board planning requirements have evolved over time, and different regulatory instruments have been issued in response to specific regulatory needs. Figure 1 illustrates the Board's current regulatory framework. It sets out the relationships between a distributor's asset management and network investment planning processes, notes the Board's regulatory instruments that call for distributors to file certain network planning information, and identifies the information to be provided.[9]

The Board's filing requirements identify the planning horizon for different types of investment. Section 2.5.2.4 of the Board's *Filing Requirements for Transmission and Distribution Applications* (the "CoS Filing Requirements")[10] stipulates that, at a minimum, a three-year forecast of capital expenditures, covering the test year plus two

[9] Section 2 of the *Staff Discussion Paper on Distribution Network Investment Planning* summarizes the Board's current approach.
[10] Revised version issued June 28, 2012.

subsequent years, must be filed. The Board's *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence*[11] ("GEA Filing Requirements") state that "GEA Plans" should cover a five year horizon. The Board understands that distributors typically use five- to ten-year horizons for their own internal planning purposes. The GEA Filing Requirements are currently the only ones that integrate regional considerations and call for broader consultation

Stakeholder Views

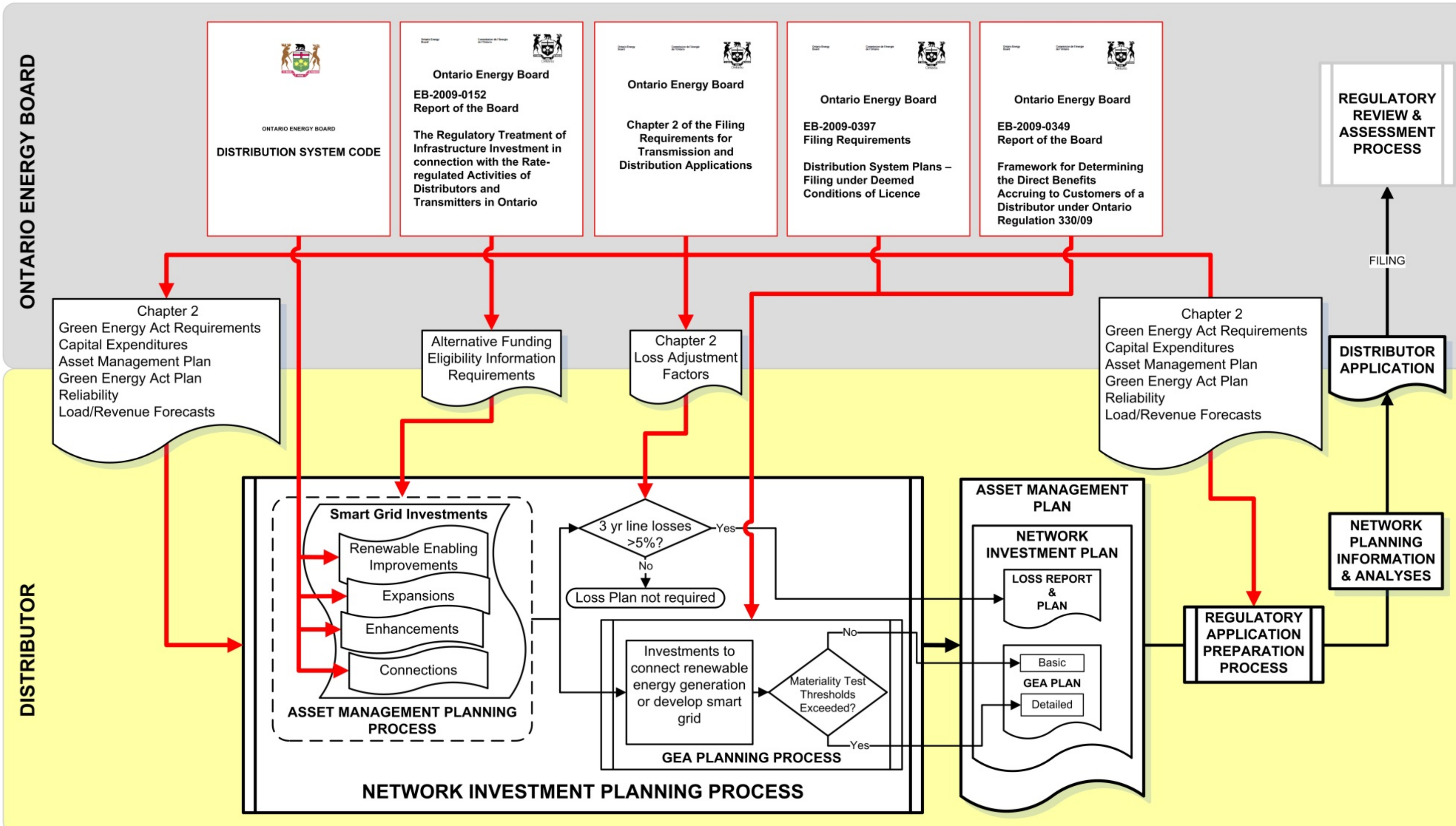
There was wide-spread stakeholder support for integrated network planning, although some stakeholders noted that certain investment drivers are inherently unpredictable. Stakeholders suggested that integrated planning would facilitate the identification and analysis of trade-offs amongst different investment options, promote sustainable least cost planning, and support optimized regional infrastructure planning.

Stakeholders generally agreed that a longer term view is needed in relation to investment planning, noting among other things that a multi-year approach better accommodates planning for large investments and allows greater scope to prioritize and pace investments and smooth rate increases. Reconciling long-term capital planning with shorter-term rate cycles and accommodating differences between transmission and distribution investments in terms of the time between planning and "in service" status were noted as challenges. Distributors largely favoured a planning horizon of three to five years as the minimum standard. Some stakeholders suggested that planning information be updated annually.

Several stakeholders underscored that the implementation of an integrated approach to planning must include the consolidation, simplification or standardization of the Board's various planning-related filing requirements.

[11] Revised version issued May 17, 2012.

Figure 1: Current Regulatory Framework for Distribution Network Planning



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The Board's Conclusions

The Board concludes that, in order to have distribution plans that support the Board's performance outcomes approach to rate-setting, an integrated approach to infrastructure planning is required. Under an integrated approach, all categories of network investments will be planned together, including investments for the renewal and expansion of networks and, where applicable, investments for the connection of renewable generation facilities, investments for smart grid development and implementation, and investments identified in the course of regional infrastructure planning exercises. An integrated approach to planning will provide a foundation for the setting of distribution rates and lead to optimized investments that support the achievement of the outcomes identified by the Board.

The Board will work to consolidate its various planning-related filing requirements. Harmonization and consolidation of these regulatory requirements can facilitate planning that will better support the achievement of the desired outcomes of the renewed regulatory framework. To the extent practicable, the terms and definitions used for asset management and investment planning information filings will be standardized to enhance clarity, consistency, and comparability. Also to the extent practicable, the Board will develop standardized requirements for capital plans and related filings.

Figure 2 provides a high level illustration of this approach, the main elements of which are discussed in later sections of this Chapter.

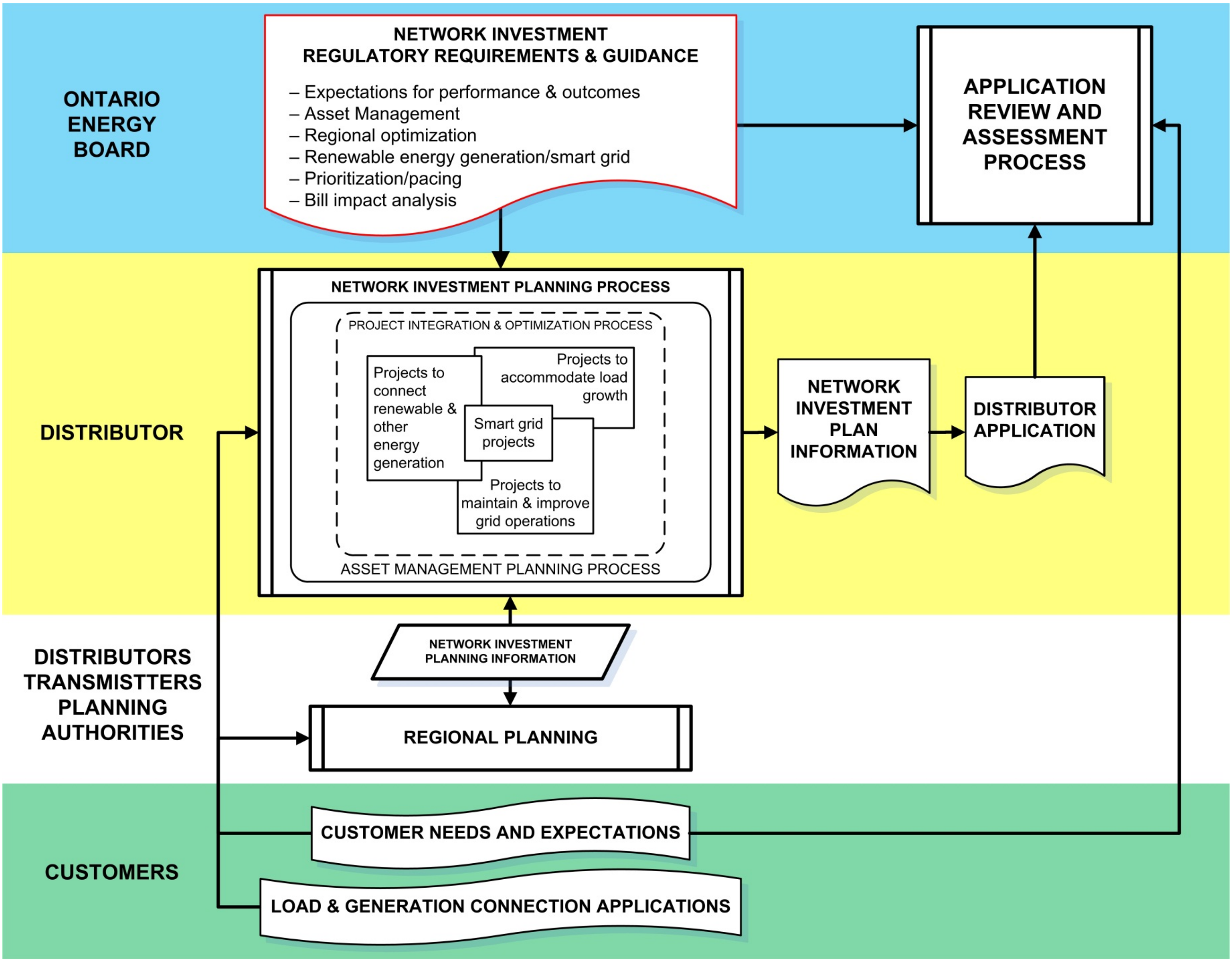
The Board further concludes that a planning horizon of five years is required to support integrated planning and better align distributor planning cycles with rate-setting cycles. This time horizon, along with the integrated approach to planning, will allow distributors to pace and prioritize projects with a view to the impact on the total bill for customers.

This planning horizon should also enhance cost predictability for both the distributor and its customers.

All distributors will therefore be required to file network investment planning information for five forecast years (where the initial or test year is the first forecast year) as part of any application for the rebasing of their rates under 4th Generation IR, or for the setting of their rates under the Custom IR method. Distributors using the Annual IR Index method will also be required to file a plan at intervals to be specified by the Board. The scope and level of detail required in the plan will depend on the scope and magnitude of the capital investments the plan is intended to support.

The Board will also monitor and measure plan implementation and plan achievement as discussed in Chapter 4.

Figure 2: Integrated Approach to Distribution Network Planning



3.1.2 The Board's expectations for asset management and investment planning

Since 2009, the Board has required distributors to file an asset management plan if available. Where no asset management plan is available, the distributor must file information outlining its approach to the planning and prioritization of capital projects.[12]

Stakeholder Views

There was a general recognition that greater standardization of asset management plans in terms of concepts, definitions and key plan elements is needed to reduce costs, facilitate regulatory review and enhance regulatory predictability.

Stakeholders suggested different approaches for addressing uncertainty in the context of a multi-year planning horizon and for avoiding the adverse impact that deferred investments can have on customer rates. A "best practice" approach to asset management planning was suggested as a means of ensuring that investments are adequately supported and justified in distributor asset management plans.

The Board's Conclusions

The Board concludes that further development and rationalization of the Board's filing requirements should be undertaken to assist the production of planning information to better support distribution rate setting. The Board will further engage stakeholders in the development of standard requirements for asset management and capital plans. The standard requirements will facilitate the testing of the plans and ensure that the Board's expectations are clear to utilities and other stakeholders.

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[12] *CoS Filing Requirements*, section 2.5.2.4.

3.1.3 Tools and methods to support proposed investments

The Board's filing requirements identify minimum requirements with respect to the quantitative data and qualitative information that is to be provided by distributors as part of their filings. The onus, however, remains on a distributor to provide the data, information and analyses necessary to justify the forecasted costs that are the basis for the distributor's proposed rates. Filings must enable the Board to assess whether and how a distributor has sought to control costs in relation to its proposed investments through the appropriate optimization, prioritization and pacing of investment expenditures.

There is a need, therefore, to consider whether specific qualitative and quantitative analyses should be required to assist the Board in its review and consideration of distributor investment plans. Whether and how experts might be used to assist in the assessment of distributor investment plans and planning processes was also noted for consideration.

Stakeholder Views

Some stakeholders endorsed the involvement of independent third party experts in the assessment of distributor planning processes and filings. It was noted that this is currently a practice in the United Kingdom, and that some Ontario distributors already routinely use third party experts for plan evaluation purposes.

Stakeholder proposals for tools and methods to support and justify distributor investments included specific quantitative analyses and verifiable or authoritative qualitative information. A variety of data and quantitative analyses were suggested.

Stakeholder views varied on bill impact estimations and associated tools. Some stakeholders were supportive of a requirement that distributors consider forecasts of the 'total bill' when developing their spending plans, identifying this as essential to the pacing and prioritization of investment in a manner that controls year-over-year rate increases and to reducing the need for mitigation at the time of Board approval. Others noted that some costs on the total bill are outside of a distributor's control, and that increases in these costs should not result in automatic offsetting adjustments to distribution investment spending.

The Board's Conclusions

As indicated in the Introduction to this Report, the Board's first two statutory objectives are key considerations for the policies described in this Chapter. Pacing and prioritization of capital investments to promote predictability in rates and affordability for customers must be a primary goal in a distributor's capital plan. The Board recognizes that factors beyond a distributor's control may add complexity and uncertainty to any effort to estimate bill impacts on customers. However, a distributor must exercise control over the pace of its own capital spending, as this factor can be an important element in the total cost of electricity to customers. To aid distributors in this essential task, standardized methods and tools should be developed for use by distributors in the preparation of their plans. In addition, the Board sees merit in receiving the evidence of third party experts as part of a distributor's application, or retaining its own third party experts, in relation to the review and assessment of distributor asset management and network investment plans (along with other evidence filed by the distributor).

The Board will further engage stakeholders on the identification and development of qualitative and quantitative approaches and tools to be used by distributors to support their investment proposals, including methodologies to assist in prioritizing and pacing proposed investments in consideration of the total bill impact on customers. The output of any methodology will need to be transparent, robust and reproducible, and include forecast information from independent and authoritative sources where these are publicly available.

3.2 Regional Infrastructure Planning

3.2.1 Background

Regional planning has been undertaken for many years in Ontario. However, until recently most distributors focused almost exclusively on the delivery of electricity to their own load customers. The *Green Energy and Green Economy Act, 2009* has created an increased need for coordinated planning among distributors and transmitters, and also among neighbouring distributors, on a regional basis. The development and implementation of the smart grid will also require regional coordination. [13]

3.2.2 Integration of Regional Considerations

Some Ontario utilities are already engaged in regional or otherwise coordinated planning exercises or discussions. In the context of the Board's conclusion that more integrated planning is needed in the renewed regulatory framework, the question is whether a more structured approach to regional infrastructure planning is required.

Stakeholder Views

Many stakeholders were supportive of a more formal approach to regional planning as a means of addressing key concerns with the current approach. In their view, the current approach is not sufficiently inclusive (in particular, ratepayer interests are under-represented) and a more formal approach would address this issue and ensure participation by all distributors. Other stakeholders, however, were of the view that the current approach is adequate.

[13] The Minister's Directive referred to later in this Chapter identifies regional coordination as a policy objective to guide the Board in the development of guidance to the industry on the development and implementation of the smart grid.

There was general agreement that any regional planning process should be a "one-step" process, with the Ontario Power Authority ("OPA"), the relevant transmitter and the relevant distributors involved in developing a single regional plan. There was also general agreement on the need for all potential solutions, including distribution and transmission infrastructure, distributed generation and conservation and demand management ("CDM") solutions, to be considered in the context of a new regional planning process.

Some stakeholders suggested that regional plans should be approved by the Board, whether separately or in the context of a rate or leave to construct proceeding.

The Board's Conclusions

The Board concludes that infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into utility planning processes, which will, in turn, help promote the cost-effective development of electricity infrastructure in the Province. The effective use of regional infrastructure planning and the inclusion of regional considerations in distributors' and transmitters' plans will also be key in ensuring that the development and implementation of the smart grid in Ontario is carried out on a coordinated basis and that smart grid investments are made at the system level (distribution or transmission) that will best serve the interests of the region.

Distributors and transmitters will therefore be expected to file evidence in rate and leave to construct proceedings that demonstrates that regional issues have been appropriately considered and, where applicable, addressed in developing the utility's capital budget or infrastructure investment proposal. The Board does not expect that a formal regional infrastructure plan will be required in all instances to satisfy this filing requirement. While the Board will consider regional infrastructure plans in its regulatory processes, the Board will not formally approve these plans.

The Board believes that effective regional infrastructure planning will be best achieved by allowing relevant stakeholders a further opportunity to build on their practical experience and on the input received through this consultation to date. The Board will convene a stakeholder working group to prepare a report that sets out the details of appropriate regional infrastructure planning processes, that designs the outputs of the planning process and that identifies any changes to the Board's regulatory instruments that may be needed to support the process. The Board expects the following to be reflected in that report:

- The Board expects regional infrastructure planning to be more structured, and therefore lead responsibility must be assigned. The Board believes that there is merit in having this responsibility lie with the appropriate transmitter. The transmitter will work with the OPA to identify where CDM or distributed generation options may represent potential solutions.

- Regions that will form the foundation for the process will be identified, such that all distributors will have an understanding of the regions within which they reside. The Board sees merit in having predetermined regions that are based on electrical system boundaries, and suggests that the Independent Electricity System Operator's electrical zones be used as a starting point.

- Protocols will be in place for the sharing of information among relevant parties.

- Distributors will be expected to participate in regional infrastructure planning processes.

Following receipt of that report, the Board will determine whether any changes to its regulatory instruments are required.

3.2.3 Facilitating the Implementation of Regional Infrastructure Planning through Amendment of Board Codes

Two issues relating to cost responsibility for transmission connection assets have been identified as potential impediments to the implementation of regional infrastructure planning and the execution of regional infrastructure plans.

The first issue (the "Otherwise Planned and Refund" issue) is centered on sections 6.3.6 and 6.2.24 of the Transmission System Code ("TSC"). As a general rule under the TSC, cost responsibility for transmission connection assets lies with the transmission customer, who may be required to make a capital contribution before the asset is built. Section 6.3.6 of the TSC creates an exception by stating that a capital contribution is not required for connection facilities that are "otherwise planned" by the transmitter. Section 6.2.24 of the TSC contemplates that, where a customer has made a capital contribution for the construction of a connection facility and that capital contribution includes the cost of capacity not needed by the customer, the customer is entitled to a refund of a portion of the capital contribution if that capacity is later assigned to another customer. However, that entitlement to a refund ends five years after the connection facility comes into service.

The second issue (the "Transmission Asset Definition" issue) pertains to the definition of certain transmission connection assets and the cost responsibility consequences that flow from that definition. Specifically, the question is whether certain line connection assets are more appropriately treated as network assets for cost responsibility purposes.

Stakeholder Views

Otherwise Planned and Refund Issue

Stakeholders generally agreed that changes to the current TSC cost responsibility rules for line connection assets are required to facilitate regional infrastructure planning and the ultimate execution of regional plans. Stakeholders were also broadly supportive of a shift away from the current emphasis on a 'trigger' pays model in relation to new or upgraded line connection investments.

It was noted that section 6.3.6 of the TSC can act as a disincentive to joint planning between the transmitter and distributors and that there are ambiguities in relation to when or how that section applies, as previously acknowledged by the Board.[14]

Some stakeholders identified that the effect of the five-year sunset proviso in section 6.2.24 of the TSC is that later-arriving customers that benefit from a connection asset are able to avoid contributing to the cost of that asset. It was noted that this can create an inappropriate incentive for a distributor to delay requesting additional capacity until after the five year period expires.

The Transmission Asset Definition Issue

Stakeholders were generally supportive of redefining line connection assets. Among the concerns noted with the current cost responsibility regime is that it does not take into account the evolutionary nature of the transmission system and that, in some

[14] In its September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), the Board stated that *"[T]here can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other….That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required."*

cases, a distributor is responsible for the costs associated with line connection assets that perform functions beyond simply supplying the distributor.

However, stakeholders were divided on the scope of the proposed redefinition. Some stakeholders suggested that line connection assets be defined as network assets in all cases. Others proposed that line connections be so defined only in cases where such line connection assets provide other functions beyond supplying a distributor, citing the example of Dual Function Lines.[15]

It was also noted that line connection assets are not currently classified in a consistent manner. In particular, in about 50% of the cases 115/230 kV auto-transformers are currently classified as network assets (and the costs recovered from all Ontario ratepayers), while in the remaining 50% of the cases they are classified as line connection assets (and the costs recovered from only the triggering distributor and its customers). It was further noted that all distributors in a region benefit from a 115/230 kV auto-transformer, and that it is essentially impossible to determine the extent to which each transmission customer benefits from such an asset.

The Board's Conclusions

Otherwise Planned and Refund Issue

The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard.

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[15] The definition of certain line connections as Dual Function Lines was approved by the Board in Hydro One's EB-2006-0501 transmission rate proceeding. It addressed the Board's concerns associated with the Line Connection pool in the RP-1999-0044 transmission rate proceeding, where the Board stated that it expected the definition of the Line Connection pool to be reconsidered in Hydro One's next cost allocation and rate design proceeding.

The reference to “otherwise planned” in section 6.3.6 of the TSC implies that a transmitter is expected to plan investments without the input of transmission customers, including distributors. This is incompatible with the Board’s approach to regional infrastructure planning set out above. The Board will therefore initiate a process to propose the removal of section 6.3.6 of the TSC.

The Board also concludes that the five year limit on the requirement to provide a refund to the initial transmission customer or customers that provided a capital contribution may be creating unintended effects. The Board will therefore also propose amendments to section 6.2.24 of the TSC regarding the five-year sunset provision.

These TSC amendments would apply on a go forward basis only (i.e., only to initial customers that make a capital contribution after the amendment comes into force).

Transmission Asset Definition Issue

The Board concludes that no redefinition is required in relation to transformation connection assets for the purpose of facilitating regional infrastructure planning. However, the Board also concludes that the redefinition of certain line connection assets in a manner that better reflects the function that each asset performs will facilitate the implementation of regional infrastructure planning, and should also place distributors (and therefore all Ontario customers) on a more level playing field in terms of cost responsibility. To the extent that line connection assets are defined based on function, distributors (and their customers) will be responsible only for the costs associated with upgrades to assets that are used solely to supply a distributor or group of distributors (i.e., where such distributors are the sole beneficiaries). The end result will be somewhat akin to ‘partial’ province-wide pooling with the uploading of some transmission assets from the line connection pool to the network pool. At the same time, all distributors will remain responsible for the costs associated with some line connection assets. This approach should maintain cost discipline.

The Board has concluded that all 115/230 kV auto-transformers and the associated switchgear should consistently be defined as network assets. The rationale for classifying this subset of transmission assets as network assets was previously explained by the Board as follows:

> These unique system elements in some instances accommodate loads that are beyond a customer's requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) …. In particular, use of autotransformers is seen as a means to optimize use of the transmission system as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.[16]

The Board will further engage stakeholders in the identification of all line connection assets that perform one or more functions beyond supplying the distributor and in developing criteria to be used to assess new assets and future upgrades to existing assets for redefinition purposes. That consultation will take into account the function the asset performs, reflect the 'beneficiary' pays principle and consider the frequency with which line connection assets should be reviewed to ascertain the function they provide for the purpose of future transmission rate proceedings.

Once the stakeholder consultation has been completed, the Board expects to propose amendments to the relevant provisions of the TSC with a view to integrating the new treatment of all applicable line connection assets, and will proceed with any other changes to its regulatory instruments as may be required to give effect to those amendments.

These changes are expected to apply on a go forward basis only (i.e., to new line connection assets or to upgrades to existing line connection assets that are built after the amendment comes into force). This approach will avoid retroactive changes in cost allocation and the associated rates. As a consequence, the Board notes, only future

[16] September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), pages 24-25.

line connection upgrades have the potential to affect the execution of regional infrastructure plans.

Pooling

During the consultation process, stakeholders provided insight into the relative merits of implementing changes to the Board's cost responsibility regime that are of a more transformative nature than those discussed above. Specifically, stakeholders commented on the potential to move to the regional or province-wide pooling of transmission connection facility costs, in whole or in part. The Board has concluded that a shift to province-wide pooling carries with it the risk of cross-subsidization, the potential for transmission overbuild and an inappropriate cost shifting between regions in the province. Regional pooling would only address those risks to some extent, and would be too complex to implement as regions may change over time and a number of distributors would be included in more than one regional pool. Moreover, the Board is satisfied that a move to any form of pooling of costs is neither necessary nor desirable at this time for the purpose of facilitating regional infrastructure planning and the execution of regional plans, given how the Board is addressing the cost responsibility issues discussed above.

3.3 Development of the Smart Grid

3.3.1 Background

With the coming into force of the *Green Energy and Green Economy Act, 2009*, several provisions were added to the OEB Act in relation to the development and implementation of a smart grid in Ontario. The Board now has a statutory objective to facilitate the implementation of a smart grid on Ontario, and it is a deemed condition of license for all licensed electricity distributors and transmitters to plan for and make smart grid investments as directed by the Board.[17]

On November 23, 2010, the Minister of Energy issued a Directive to the Board requiring it to provide guidance to licensed electricity distributors and transmitters (among possible others) regarding the Board's expectations in relation to smart grid activities. In developing that guidance, the Board is to be guided by certain parameters for three objectives for the smart grid, namely, customer control objectives, power system flexibility objectives and adaptive infrastructure objectives. The Board is also to be guided by 10 policy objectives of the government, including policy objectives pertaining to efficiency, customer value, interoperability, and privacy.

3.3.2 Smart Grid Planning and Innovation

Planning for smart grid development and implementation by electricity distributors and transmitters will be an integral part of the broader network investment planning exercise, and the Board's guidance with respect to smart grid activities will be provided in a Supplemental Report of the Board. Moreover, the Board expects that smart grid development will be coordinated on a regional basis in furtherance of the government policy objective set out in the Minister's Directive to the effect that smart grid implementation efforts should involve regional coordination in order to achieve economies of scope and scale.

Smart grid investments are eligible for the application of the "alternative" mechanisms identified in the "*Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors* (EB-2009-0152)". As noted in Chapter 4, the Board intends to explore further opportunities to embed the

[17] Paragraph 4 of section 1(1) and section 70(2.1) of the OEB Act, respectively. The *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* referred to earlier in this Chapter speak to electricity distributor planning activities in respect of smart grid demonstration projects, studies, planning exercises, education or training, and establish deferral accounts for costs associated with these activities.

facilitation and recognition of technological innovation in the renewed regulatory framework. Smart grid development and implementation activities will be a central focus of that effort, given that grid-enhancing advanced technology systems and equipment are at the heart of the smart grid.

3.3.3 Treatment of Smart Grid Investments for Rate-setting

Under the integrated approach to planning described in this Report grid-enhancing advanced information and exchange systems and equipment (which are commonly referred to as smart grid) are considered integral to all utility investment. Under this approach, no distinction is made for regulatory purposes between "smart grid" and more traditional investments undertaken by distributors and transmitters – more advanced technologies are so integrated with other activities that such distinctions are not productive.

This approach to smart grid investments and activities will best support the achievement of the objectives of the renewed regulatory framework. It facilitates more fully integrated planning, and will promote economic efficiency and the better alignment of expenditures with cost recovery so as to minimize 'total bill' impacts. It is also more efficient from a regulatory perspective.

3.3.4 Demarcation of Utility Role: "Behind the Meter" Activities

One of the objectives of the smart grid set out in the Minister's Directive is customer control. Parameters for that objective include enabling access to data by authorized parties, enabling consumers to better control their consumption and providing consumers with opportunities to participate in small-scale renewable generation. The Board considers that the achievement of this customer control objective will require that "behind the meter" services and applications be available to customers. The issue of behind the meter services is closely linked to that of access to meter data. Access to meter data is key in facilitating the provision of behind the meter services and applications. The Board's regulatory framework for smart grid development and implementation should therefore facilitate data access and the implementation of behind the meter services and applications.

The question that arises is the role of distributors in the provision of behind the meter services and applications. Currently, there are private (i.e., unregulated) businesses that provide these services and applications, and that do so without Board oversight. Some distributors also provide such services on a non-utility basis as part of a CDM program. One example is the Peaksaver program offered on behalf of the OPA.

Stakeholder Views

Few stakeholders commented on this issue. One stakeholder proposed that there should be no restrictions on the provision of behind the meter services. Another maintained that distributors should be allowed to provide behind the meter CDM services, but also stated that the "demarcation should be the meter". Input was also received from the Smart Grid Working Group.

The Board's Conclusions

The Board anticipates that distributors will continue to be engaged in the provision of behind the meter services and applications that fall within the parameters set out in section 71(2) or section 71(3) of the OEB Act. In so doing, they are engaging in a non-utility activity. That activity must be accounted for separately from utility activities and be undertaken on a full cost recovery basis (in other words, not covered in rates). There is no element of natural monopoly in the market for behind the meter services and, therefore, the Board has concluded that customer control would be best served by the forces of market competition. The Board expects that this policy conclusion will assist distributors in planning and organizing their and their affiliate's activities.

3.3.5 Other Issues

Following the receipt of the Minister's Directive, Board staff consulted with the Smart Grid Working Group to produce a Staff Discussion Paper, which was issued in November 2011, and in that paper identified a number of key issues, including cyber-security, privacy, interoperability, customer access and the recognition of types of benefits flowing from smart grid in applications. Issues not addressed in this Report will be addressed in the Supplemental Report of the Board on Smart Grid.

3.4 Implementation

The Board will establish two new stakeholder working groups to accomplish activities dealing with distribution network planning and regional infrastructure planning. The Board will also reconvene its previously established smart grid working group. The principal tasks of these working groups will be:

- An Integrated Approach to Network Planning: To revise the Board's filing requirements for distributors and transmitters and issue guidance in accordance with the Board's conclusions in the Report. The development of an integrated set of revised filing requirements will include those related to distribution network planning, smart grid planning and regional planning.

- Regional Infrastructure Planning: To develop guidance regarding the implementation of the Board's conclusions in the Report related to moving to a more structured approach to regional infrastructure planning, as well as the appropriate redefinition of certain line connection assets and TSC cost responsibility rule changes to remove barriers related to regional plan execution.

- Development of the Smart Grid: To develop the regulatory documents to implement the Minister's Directive and the Board's conclusions in the Report.

The main products and timelines for these working groups are outlined in the table below. Further detail is provided in the remaining sections of this chapter.

	Product	**Planned issuance**	**Process**
Network Planning	Consolidated capital plan filing requirements	February 2013	Staff proposal on asset management and capital planning filing requirements Working group meetings Staff proposal on integrated filing requirements Working group meetings
Integrating Regional Planning	Consolidated capital plan filing requirements	February 2013	Working group meetings Working group report to Board (regional infrastructure planning process, filing requirements) Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements
	Amendments as necessary to TSC and DSC	April 2013	Working group meetings Working group reports to Board (asset redefinition, regional infrastructure planning process) Notice of proposed code amendments
Smart Grid	Supplemental Report of the Board	January 2013	Working group meetings Working group input related to filing requirements incorporated into Staff proposal on integrated filing requirements

3.4.1 Distribution network investment planning

The Board's filing requirements in relation to distributor asset management and investment planning information will be enhanced, and the Board will release Consolidated Capital Plan Filing Requirements in February 2013.

In order to implement the Board's requirements for integrated infrastructure planning, the Board will identify tools and methods to support proposed infrastructure investments in distributor applications, including the demonstration of how the distributor has optimized, prioritized and paced investments to take into consideration the total bill impact on customers.

3.4.2 Facilitating effective regional infrastructure planning

The Board will determine the regional infrastructure planning related information needed to support rate and leave to construct applications, and this will be incorporated into the Board's Consolidated Capital Plan Filing Requirements.

Key elements that need to be addressed in order to facilitate the move to a more structured regional infrastructure planning process include the following*:*

- The information a distributor should be required to provide to the transmitter for regional infrastructure planning purposes and the frequency at which it should be updated;
- The appropriate evaluative criteria to compare potential solutions;
- The circumstances under which the OPA should participate;
- The form in which broader consultation should take place before a regional plan is finalized; and
- Appropriate regional boundaries and the criteria to be used to establish them.

A Working Group Report to the Board will be produced, as well as a staff proposal for consolidated filing requirements. The Board expects that the section of the Report addressing regional infrastructure planning process matters will also provide input for the Board's consideration in relation to any other key elements that the working group believes should be addressed in order to facilitate the move to a more structured regional infrastructure planning process.

3.4.3 Facilitating the implementation of regional infrastructure planning

As noted in this Report, the Board believes that changes to the cost responsibility regime necessary to facilitate regional infrastructure planning will require the development of a set of criteria based on the function(s) that line connection assets perform. These changes will be effected through a notice and comment process to amend the relevant TSC sections.[18] Given the interconnected nature of these cost responsibility changes related to the redefinition of line connection assets and those involving TSC cost responsibility rule changes discussed above (i.e., "Otherwise Planned and Refund Issue"), the Board will address all of the proposed amendments in one notice and will propose the same implementation date for all amendments. This code amendment process will also address amendments to the TSC that may be required in relation to the regional infrastructure planning process matters discussed above.

The proposal for Code amendments will also be informed by a Working Group Report to the Board in relation to criteria for line connection asset redefinition and identifying the assets that meet those criteria. The Board expects any amendments made to the Codes will come into force in mid-2013.

3.4.4 Smart grid guidance

The Board will issue a Supplemental Report providing the Board's guidance on smart grid, including the integration of smart grid development into the overall regional and

[18] The redefinition of certain line connection assets may also require proposed amendments to other regulatory instruments of the Board.

network planning filing requirements. The Board expects to issue the Supplemental Report on smart grid policy in January 2013, and to integrate the smart grid work into the Consolidated Capital Plan Filing Requirements.

4 Performance Measurement and Continuous Improvement

The renewed regulatory framework is a comprehensive performance-based approach to regulation that promotes the achievement of performance outcomes that will benefit existing and future customers. The framework will align customer and utility interests, continue to support the achievement of important public policy objectives, and place a greater focus on delivering value for money.

The achievement of the performance outcomes will be supported by specific measures and targets and annual reporting. Distributor performance will be compared year over year, both to prior performance and to the performance of other distributors. To facilitate performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes.

Under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers.

4.1 Monitoring Distributor Performance

Under the rate-setting approach described in Chapter 2, the Board will be setting rates under longer-term plans and allowing distributors to select the rate-setting method that best meets their needs and circumstances. Distributors will be required to undertake longer-term integrated planning that captures all categories of network planning, including those reflecting regional needs, as discussed in Chapter 3.

The Board has standards and measures for performance in place today;[19] however, the Board needs to assess whether these continue to be appropriate in light of the performance outcomes defined by the Board and the new rate setting methods. The Board also needs to consider the consequences that might flow from performance that does not meet the standards.

Benchmarking will become increasingly important, as comparison among distributors is one means of analyzing whether a given distributor is as efficient as possible.

Stakeholder Views

There was general stakeholder support for meaningful, empirically-based standards, performance measures and regulatory mechanisms, provided that the implementation costs do not outweigh the value for customers. Desirable characteristics that were identified included: focus on what customers value; promoting alignment of distributor and customer interests; and ability to accommodate differences within the distribution sector.

Stakeholder suggestions for objectives to underpin the development of distributor customer service and cost performance standards and measures included furthering market development; revealing infrastructure investment planning effectiveness or cost performance; facilitating price transparency for customers; and improving existing customer service standards.

A number of stakeholders acknowledged the cost performance incentives that are inherent in incentive regulation. Caution was expressed about implementing direct financial incentives until Board-approved measures are in place. Stakeholders were divided on process incentives; some were supportive of streamlined regulatory processes for high-performing distributors while others were opposed to limits being

[19] These are identified in the *Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors.*

placed on the review of applications based on the quality of evidence or the applicant's past performance.

The Board's Conclusions

Performance Outcomes and the Electricity Distributor Scorecard

The Board is establishing performance outcomes that it expects distributors to achieve in four distinct areas:

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

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

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

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

The Board concludes that a scorecard will be used to monitor individual distributor performance and to compare performance across the distribution sector. The scorecard effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons, which are critical to the Board's rate-setting approach under the renewed regulatory framework. Distributors will be required to report their progress against the scorecard on an annual basis.

A sample of a possible scorecard based on a simple sub-set of the Board's current standards and measures (such as the service quality requirements in the *Distribution System Code*) is provided below. The sample is provided for illustrative purposes only, as the Board has not yet determined content of the scorecard to be used. The Board expects that the scorecard will evolve as appropriate standards and measures are developed to assess distributor performance against the identified outcomes.

Figure 3: Sample Scorecard

Customer Focus	Operational Effectiveness	Public Policy Responsiveness	Financial Performance
services provided in a manner that responds to identified customer preferences	*continuous improvement in productivity and cost performance; and delivery on system reliability and quality objectives*	*delivery on obligations mandated by government (specific legislation or via directives to the Board)*	*financial viability maintained; and savings from operational effectiveness are sustainable*
• Customer complaints • Connection statistics • Connection of New Service • Reconnection • Telephone Accessibility • Appointments Met • Written Response to Enquiries • Emergency Response • Telephone Call Abandon Rate • Appointments Scheduling • Rescheduling a Missed Appointment	• Distribution Losses • System Average Interruption Frequency Index (SAIFI) • System Average Interruption Duration Index (SAIDI) • Customer Average Interruption Duration Index (CAIDI) • Momentary Average Interruption Frequency Index (MAIFI)	• Electricity Conservation (Kwh) • Peak Demand Reductions (kW)	• Current Ratio • Debt Service Capability • Interest Coverage • OM&A Cost per Customer • Return on Equity

Standards and Measures

The Board will engage stakeholders in further consultation on the standards and measures to be included in the distributor scorecard. The standards and measures must be suitable for use by the Board in monitoring and assessing distributor performance against expected performance outcomes, in monitoring and assessing distributor progress towards the goals and objectives in the distributor's network investment plan, in comparing distributor performance across the sector and identifying trends, and in supporting rate-setting.

The Board has established a set of objectives to guide the consultation. Standards and measures should:

- be aligned with, and reflect a distributor's effectiveness in achieving, the performance outcomes listed in Chapter 1;
- be reflective of customer needs and expectations;
- encourage year-over-year performance gains;
- reveal current performance and signal future performance;
- reflect a distributor's effectiveness in prioritizing and pacing investment (with regard to total bill impacts) and implementing its capital plan;
- be measureable by each distributor, and be aligned with their reporting for their own internal purposes to the extent possible;
- consider the characteristics of a distributor's service territory; and
- be practical.

4.2 The Role of Benchmarking

The Board's regulatory oversight of electricity distributors is supported by benchmarking. Expanded use of benchmarking will be necessary to support the Board's renewed regulatory framework policies.

Stakeholder Views

There was general support for the continued development and use of benchmarking tools, with further empirical work on the distribution sector identified as a priority. It was noted that the cost of this exercise should not exceed its value, recognizing that there may be limits to the practical use of cost comparison and benchmarking information. Among suggestions offered for the further use and development of benchmarking tools were the use of external data, benchmarks and productivity trends to establish boundaries within which distributors should operate; the more rigorous implementation of benchmarking in rate proceedings; and the adoption of a “balanced scorecard” approach to benchmarking to reflect customer and distributor diversity.

The Board’s Conclusions

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4^{th} Generation IR and the Annual IR Index, and will inform the Board’s review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor’s rates are set, the distributor will continue to be included in the Board’s benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.

4.3 Regulatory Mechanisms

The Board is committed to ensuring optimal performance and value for customers, and will continue to enhance its regulatory mechanisms where necessary to achieve this goal. In initiating the performance-based approach, the Board will maintain its existing regulatory mechanisms, subject to certain refinements. Specifically, the X-factor will be refined as discussed in Chapter 2 and the “publication of distributor results” mechanisms referred to above (among possible others) will be integrated into the electricity distributor scorecard.

The Board’s incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board’s current policies as set out in the *Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario’s Electricity Transmitters and Distributors*, the Board expects that new approaches may be required.

In addition, appropriate consequences should flow from unsatisfactory performance against the Board’s standards, in order to maintain the integrity of the Board’s outcome-based approach and its approach to rate-setting.

Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- The establishment of an “efficiency carry-over” mechanism;
- Development of incentives to;
    - reward superior performance;
    - encourage innovation;
    - encourage asset optimization; and
- Potential consequences for inferior performance.

The development of these regulatory mechanisms will be aligned with the standards and measures referred to above.

4.4 Implementation

To establish the outcome based framework and provide for effective monitoring of distributor performance, the Board will:

- define the standards and measures that will be applicable to distributors;
- establish benchmarking models (through further empirical work);
- establish the reporting requirements applicable to distributors, including the format of the performance scorecard; and
- determine the regulatory mechanisms that will be used in conjunction with those standards and measures (in due course).

A stakeholder working group will be established to provide staff with expert assistance and to help staff review and evaluate proposals regarding performance standards, measures, and the development of benchmarking. This will also include consideration of rate adjustment indices (i.e., inflation and X factors). Staff and consultant reports will be issued for comment.

With respect to benchmarking, the objective is to establish total cost benchmarking for the 2014 rate year. Further work will involve comprehensive benchmarking (i.e., model(s) that combine standards for utility customer service and cost performance) to be applied in subsequent rate years.

The end result of this work will be a Supplemental Report of the Board expected to be issued in mid-2013. Regulatory instruments such as the Reporting and Record Keeping Requirements will be amended as necessary to implement the Supplemental Report.

Work carried out in this consultation to develop total cost benchmarking will provide the foundation for the development of the Board’s approach to comprehensive benchmarking. The overall approach and timeline for such additional work will be issued after the substantial completion of work planned for implementation for the 2014 rate year.

	Product	Expected issuance	Process
Standards and measures	Supplemental Report of the Board, including distributor scorecard	June 2013	Staff proposal Stakeholder meeting Working group meetings Board staff report to the Board (for comment) Stakeholder meeting Written comments
	Amendments to RRR if needed	July 2013	Notice and comment
Benchmarking	Supplemental Report of the Board (same document as above), plus consultant report on approach to total cost benchmarking	June 2013	Validation of data by distributors Consultant Concept paper Stakeholder meeting Working group meetings Consultant report (for comment) Stakeholder meeting Written comments

4.4.1 Issues to be addressed in relation to standards, measures and regulatory mechanisms

Working with stakeholders, the Board will consider the following areas in the context of developing a scorecard and performance standards, and measures to facilitate annual monitoring of distributor performance.

Assessing performance outcomes:

- confirm the standards and measures that best reflect a utility's effectiveness and/or continuous improvement in achieving the performance outcomes.

Effective planning & implementation:

- establish measures that best reflect a distributor's effectiveness with respect to:
    - planning - prioritizing and pacing investment with regard to total bill increases to consumers;
    - plan implementation – progress in achieving targets against the capital plan; and
    - plan achievement – achievement of the goal(s)/outcome(s) originally committed to in an approved capital plan

Regulatory reporting:

- establish the electricity distributor scorecard to effectively organize how utilities report on their performance to the Board.

Regulatory Mechanisms:

In due course, the Board will further engage stakeholders to consider the appropriate form and implementation of:

- an "efficiency carry-over" mechanism; and
- performance incentives to reward achievement of utility plan objectives, and/or encourage and reward implementation of truly innovative technologies to address system and customer requirements.

4.4.2 Issues to be addressed in relation to benchmarking

The use of OM&A data to benchmark distributors for stretch factor assignment purposes in the 3rd Generation IR plan is the foundation for a more comprehensive (e.g., total cost) benchmarking approach. Work to develop the more comprehensive benchmarking model(s) will also create the dataset necessary to estimate Ontario TFP trends.

The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the utility customer service and cost performance outcomes, including total cost benchmarking and an Ontario TFP study. This work will inform the Board determination on inflation and X factors for rate-setting.

The Board will also determine how to make expanded use of benchmarking for assessing distributor performance as well as to inform rate setting. In particular, the Board will establish how its standards for utility service and cost performance and various empirical tools and benchmarking will further inform (a) utility planning processes, (b) utility applications to the Board, and (c) the Board's review processes.

5 Implementation and Transition

5.1 Implementation

As noted throughout the Report, additional work is required in each of the three policy areas to implement the Board's renewed regulatory framework. The policies set out in this Report are integrated and therefore will be implemented in a coherent sequence and in a manner that allows them to interact effectively. The complete listing of activities planned over the next several months is included in Appendix B.

As outlined in the implementation section of previous chapters, the Board will establish three stakeholder working groups to provide staff with expert assistance and to review and advise staff on proposals regarding the implementation tasks. The first working group will focus on performance, benchmarking and rate adjustment indices. The second group will address outstanding matters with respect to network investment planning, and the third will work on development of regional infrastructure planning processes. In addition, the Smart Grid Working Group will be reconvened. The stakeholder members of the working groups will be selected by the Board. By sharing certain members in common, working group efforts will be coordinated and mutually informed on an on-going basis.

Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies. The Board expects that the policies in relation to the conclusions set out in this Report will be largely implemented in time for the 2014 rate year.

5.2 Transition

The Board expects that the three new rate setting methods will be available for the 2014 rate year. At that time, distributors may select the appropriate rate setting method for their utility.

The Board has established a transition plan to facilitate the early adoption of the three new rate-setting methods. The Board is aware that the preparation of a rate application can be a lengthy and resource-intensive effort. In devising the implementation and transitional measures described in this Report, the Board is attempting to balance the interest in having the new rate-setting methods available to most distributors for the 2014 rate year with the recognition of the time needed to prepare applications under the new methods. A set of tables have been provided below that represent the transition options that distributors have based on their current status in the 3rd Generation IR plan, and the timing of their rate year.

Option 1 – 4th Generation IR

Transition to full 4th Generation IR will depend on when a distributor is next scheduled to rebase under cost of service.

Option 1a – Distributor completes remaining term of 3rd Generation IR

Those distributors who are within the term of their current 3rd Generation IR (in other words are scheduled to rebase for January 1, 2015 rates or later) will continue to have their rates adjusted annually for the remaining years of their 3rd Generation IR term. The adjustment mechanism will be the same as that used for 4th Generation IR. Filing requirements for these annual adjustment applications will be available for January 1, 2014 rates.

The Board discourages distributors who are not currently scheduled to be rebased for 2014 rates from filing applications for early rebasing under the 4th Generation IR method. The Board will continue to apply the criterion regarding early rebasing enunciated in its letter of April 20, 2010: that is, that a distributor must clearly demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM period.

Option 1b – Distributor Rebases under 4th Generation IR

Complete filing requirements (including Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements) will be available for rebasing applications under 4th Generation IR for May 1, 2014 rates. In order to provide some additional time to prepare applications, these rebasing applications may be filed by October 1, 2013. When a distributor rebases using the 4th Generation filing requirements, the total term will be 5 years.

For distributors scheduled to rebase for 2014 and planning to seek the Board's approval for January 1 rates, there will be two options available:

1) Rebase under 3rd Generation IR filing requirements (in other words, without the 5 year capital plan) and remain under IR for 4 years total (rebasing plus 3 years) with rates adjusted annually using the 4th Generation IR annual adjustment
2) Delay rebasing by one year - rebase for January 1, 2015 rates, in which case the application will be filed using the Cost of Service Filing Requirements and Consolidated Capital Plan Filing Requirements, and the total term will be 5 years.

Option 2 - Move to the Annual IR Index

Distributors may file for rates under the Annual IR Index at any time. Filing requirements for the Annual IR Index will be available for January 1, 2014 rates. Distributors on the

Annual IR Index method will be required to file five-year capital plans in accordance with the Consolidated Capital Plan Filing Requirements on a periodic basis, and perhaps as soon as with applications for May 1, 2014 rates. This timing will be confirmed when the Board issues the Consolidated Capital Plan Filing Requirements.

Option 3 - File a Custom IR application.

Distributors may file for a Custom IR as soon as the Consolidated Capital Plan Filing Requirements are available. This option will not be available for January 1, 2014 rates, but will be available for purposes of setting May 1, 2014 rates or later.

Distributors may make a Custom IR application any time within a 3rd or 4th Generation IR or Annual IR Index term. The Board will permit an exception to the early rebasing test for distributors applying under the Custom IR method in advance of their normal rebasing date. The Board's view is that the Custom IR method should be available as soon as possible for distributors with prolonged elevated investment needs. One of the Board's main concerns with early rebasing is the opportunity it affords distributors to avoid the efficiency incentives in the annual adjustment mechanism. The Board is satisfied that the Custom IR process will be sufficiently rigorous that an assessment of the adequacy of past and future productivity levels can be made and the results of that assessment can be incorporated into the distributor's future rates.

The Board anticipates that there could be a significant case load for the determination of 2014 rates as a consequence of the implementation of the new framework. Delays may occur. Any distributor intending to apply under the Custom IR method for 2014 rates is encouraged to speak with Board staff at an early point to discuss scheduling.

The Board does not intend to publish filing requirements for the Custom IR method (other than the Consolidated Capital Plan Filing Requirements) at this time, although much of the material in Cost of Service Filing Requirements will be relevant for Custom IR filers. Consistent with the conclusions set out in this Report in relation to the Custom

IR method, the onus will be on the applicant to specify and substantiate its preferred approach to multi-year rate-setting. After the Board has gained some experience with these types of applications it may publish filing requirements for Custom IR applicants.

Figure 4: Transitional Measures for Rates for May 1, 2014 or Later

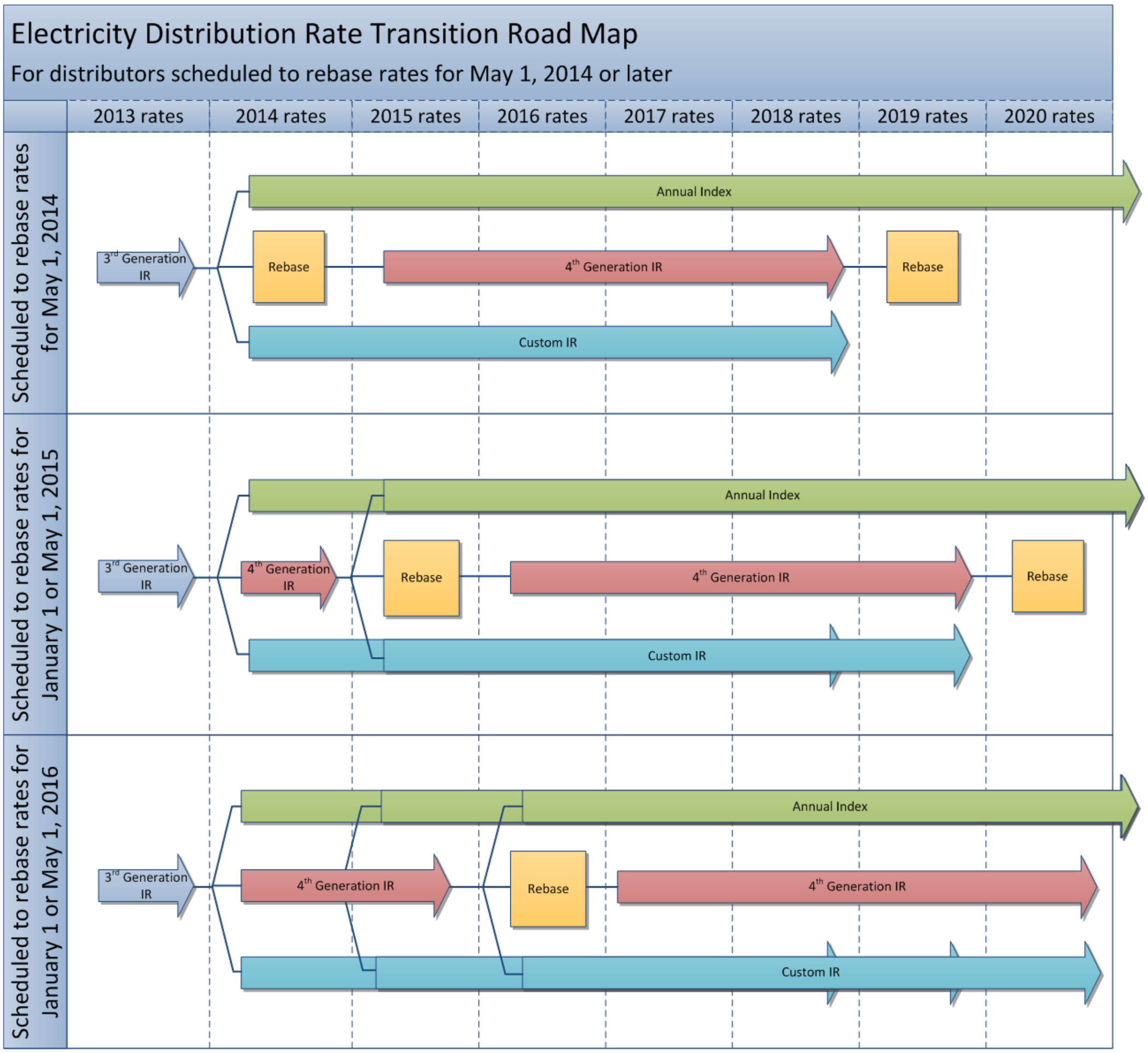
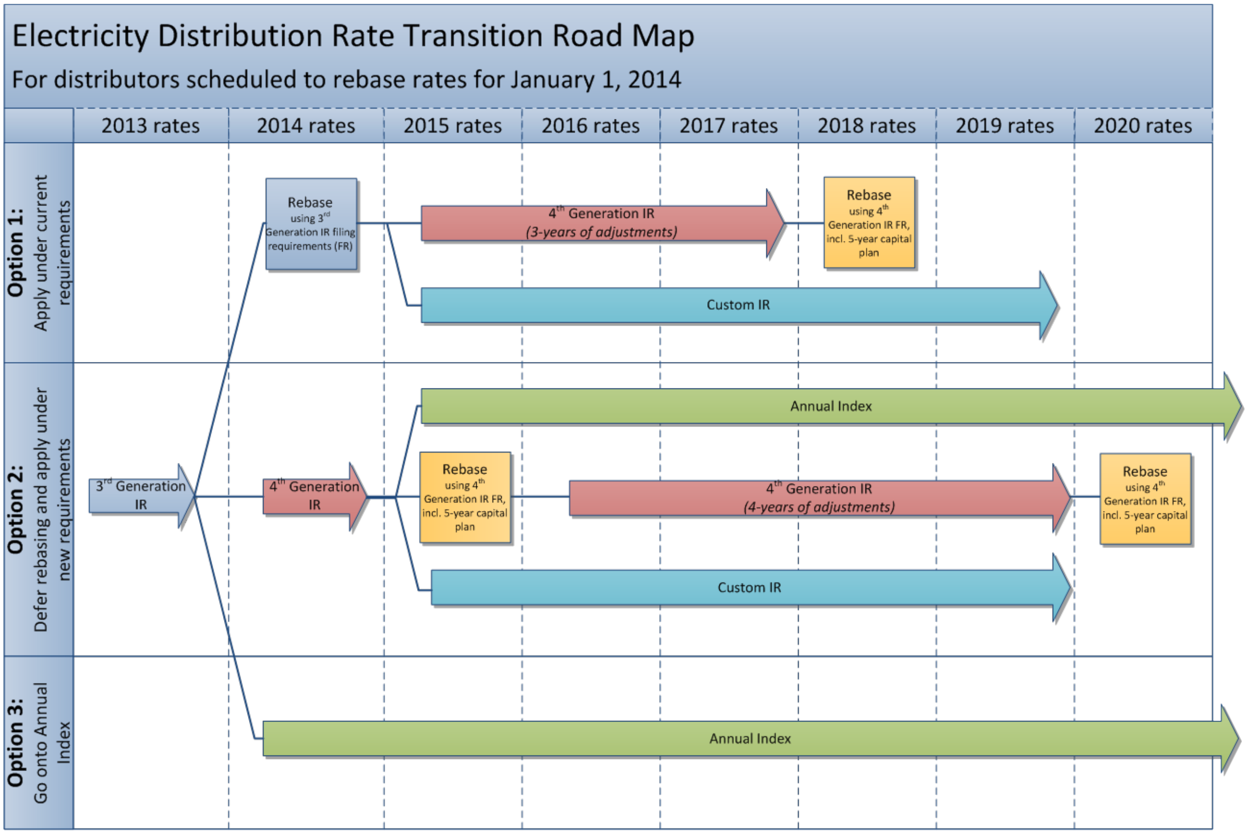


Figure 5: Transitional Measures for Rates for January 1, 2014



Appendix A: Summary of Consultation Activities to Date

Unless otherwise indicated by a prefacing identifier, all five inter-related initiatives were addressed in coordinated consultation activities.

Date	Issue / Document
Oct 27-10	The Board issued a letter announcing its intention to develop a Renewed Regulatory Framework for Electricity. • Letter
Dec 17-10	The Board issued a letter a letter initiating a consultation process to develop three key elements to a Renewed Regulatory Framework for Electricity. • Letter
Jan 13-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Ontario Energy Board is initiating a consultation with stakeholders on the implementation of Smart Grid. The Board invites all interested parties to participate in this consultation - a Smart Grid Working Group (SGWG). Nomination to participate in the working groups is due January 24, 2011. • Letter
Jan 27-11	Board staff has posted material for the Stakeholder Conference to be held on February 2nd. • Instructions on How to Join the Stakeholder Conference via WebCast (for those not attending in person) • Draft Agenda • Presentations o Overview o Distribution Network Investment Planning (EB-2010-0377) o Rate Mitigation (EB-2010-0378) o Defining and Measuring Performance of Electricity Distributors and Transmitters (EB-2010-0379)
Jan 31-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board received the following Smart Grid Working Group Submissions: • Accenture • Association of Major Power Consumers in Ontario • Bell Canada • Bluewater Power Distribution Corporation • Building Operators and Managers Association • Cambridge and North Dumfries Hydro Inc. • Capgemini

Date	Issue / Document

	• Certicom Corp.
	• Chatham-Kent Hydro
	• Cornerstone Hydro-Electric Concepts
	• David O'Brien
	• Direct Energy Marketing Ltd.
	• Electrical Safety Authority
	• Electricity Distributors Association
	• Elenchus Research Associates
	• Elster Metering
	• Enbala Power Networks
	• Enbridge Gas Distribution Inc.
	• Energate - 1
	    o Energate - 2
	    o Energate - bio
	• Energent Inc.
	• Energy Aware Technology Inc.
	• Enersource
	• Erie Thames Powerlines
	• Festival Hydro Inc.
	• GE Digital
	• General Motors of Canada
	• Honeywell
	• Horizon Utilities
	• Hydro One Networks Inc.
	• Hydro Ottawa Ltd.
	• IBM
	• Independent Electricity System Operator
	• Just Energy
	• Kinectrics Inc.
	• London Property Management Association
	• Measurement Canada
	• Metering Support Services Canada Inc.
	• Milton Hydro Distribution Inc.
	• Oakville Hydro Electricity Distribution Inc.
	• Ontario Sustainable Energy Association
	• PowerStream Inc.
	• Regen Energy - 1
	• Simpleafy
	• Society of Energy Professionals
	• Telvent
	• Thunder Bay Hydro Electricity Distribution Inc.
	• Toronto Hydro-Electric System Ltd.
	• Utilismart Corporation
	• Utilities Kingston
	• Veridian Connections Inc.

Feb 14-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): Board staff today issued a letter on the selection of Smart Grid Working Group members • Letter

Date	Issue / Document
Apr 1-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board initiated a consultation aimed at promoting the cost-effective development of electricity infrastructure through coordinated planning on a regional basis between licensed distributors and transmitters. • Board letter on Regional Planning and participation
May 4-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): Stakeholder Meeting • Agenda
Jun 3-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has issued Meeting Notes from the Stakeholder Meeting on Regional Planning. • Meeting Notes
Nov 8-11	The Board has issued a set of staff discussion papers and supporting consultant reports for the initiatives set out below. Details on the consultation process are set out in the cover letter. • Cover Letter • Distribution Network Investment Planning • Approaches to Mitigation for Electricity Transmitters and Distributors • Defining and Measuring Performance of Electricity Transmitters and Distributors • Developing Guidance for the Implementation of Smart Grid in Ontario • Regional Planning for Electricity Infrastructure • FAQs: Renewed Regulatory Framework for Electricity
Nov 8-11	Developing Guidance for the Implementation of Smart Grid in Ontario (EB-2011-0004): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper
Nov 8-11	Regional Planning for Electricity Infrastructure (EB-2011-0043): The Board has posted a Staff Discussion Paper. • Staff Discussion Paper

Date	Issue / Document
Nov 23-11	The Board's letter dated November 8, 2011, invited interested stakeholders to participate in a two-day Information Session on the staff discussion papers and consultant reports issued that day. The session will be held on December 8 and 9, 2011. The purpose of this informal session is to give participants an opportunity to ask clarifying questions to better understand the documents. Today, Board Staff posted details regarding stakeholder participation at that session. • Details on Staff Information Session **Questions in Advance Encouraged** To facilitate an efficient and useful session, participants are encouraged to send written questions in advance to Board staff at RRF@OntarioEnergyBoard.ca. Please provide document references, if any, with your questions. Questions provided in advance will be used by staff to help kick off the session.
Dec 6-11	Board staff posted a draft agenda for the two-day Information Session planned for December 8 and 9, 2011. • Draft Agenda
Dec 9-11	Board staff posted the questions that participants of the two-day Information Session provided in writing. • Canadian Manufacturers & Exporters o December 2, 2011 Letter o Questions o Brief • Consumers Council of Canada • Electrical Contractors Association of Ontario • Just Energy Ontario LP • Low-Income Energy Network • Ontario Power Authority • Pollution Probe • Power Workers' Union • School Energy Coalition
Dec 12-11	Board staff posted material shown at the December 8 – 9 Information Session. • Power Advisory 'Bill Impact Estimation Model' presentation
Feb 6-12	The Board has issued a letter providing an update to interested stakeholders on the consultation process for its initiative to develop a renewed regulatory framework for electricity distributors and transmitters. • Letter • Attachment A - "straw man" model Regulatory Framework

Date	Issue / Document
Feb 22-12	The Board has issued a letter inviting interested stakeholders to a Stakeholder Conference, scheduled for **March 28 – 30, 2012**, as part of the Board's consultation process to develop a renewed regulatory framework for electricity distributors and transmitters. **Please note, participants are asked to register in advance by e-mail to RRF@ontarioenergyboard.ca by 4:30 p.m. on March 9, 2012**. • Letter
Mar 2-12	Regional Planning for Electricity Infrastructure (EB-2011-0043): In the Board staff information session on the Renewed Regulatory Framework for Electricity held on December 8/9, 2011, clarification of the Ontario Power Authority's ("OPA") current regional planning process was requested. In response, the OPA provided a description of their regional planning process. • Description of the OPA's regional planning process
Mar 20-12	Board staff posted a draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Draft Agenda
Mar 21-12	Board Staff has posted materials from a series of Executive Roundtable Meetings held by the Chair during February and March 2012. • Presentation • List of Attendees • Meeting Notes: o Consolidated Notes from Executive Roundtables with Distributor o Consolidated Notes from Executive Roundtables with Consumer Groups o Notes from Executive Roundtable with Agencies & Transmitters o Notes from Executive Roundtable with Academics, Finance Industry, Consultants & PWU
Mar 23-12	Board Staff has posted the presentations filed by participants for the Stakeholder Conference to be held March 28-30. • Travis Allan, Counsel for Retail Council of Canada • Tom Brett, Counsel for Building and Office Managers Association • Jake Brooks, Executive Director, the Association of Power Producers of Ontario • Bob Chow, Director – Transmission Integration, Ontario Power Authority • Frank Cronin, Consultant to Power Workers Union • John Cyr, Counsel for Northwestern Ontario Associated Chambers of Commerce & Northwestern Ontario Municipal Association o Presentation • Susan Frank, VP & Chief Regulatory Officer of Regulatory Affairs, Hydro One Networks o Regional Planning o Investment Recovery • Robert Frank, Counsel for Electrical Contractor Association of Ontario • Marion Fraser, Director, Ontario Sustainable Energy Association • Rene Gatien, President & CEO, Waterloo North Hydro Inc.

Date	Issue / Document

	• Jack Gibbons, Consultant to Pollution Probe
	• Elise Herzig, President & CEO, Ontario Energy Association
	• Brennain Lloyd, Coordinator for Northwatch
	• Colin McLorg, Manager – Regulatory Policy & Relations, Toronto Hydro
	• Jack Robertson, Vice President & General Manager, Elster Metering
	• Andrew Roman, Counsel for Medium Size Distributors Group
	• Bruce Sharp, Consultant to Canadian Manufacturers & Exporters and co-sponsored by Consumers Council of Canada, Vulnerable Energy Consumers Coalition, School Energy Coalition, and Federation of Rental-housing Providers of Ontario
	  o Aegent OEPIF: unit price increase details
	  o Aegent OEPIF: unit price increase pie charts
	  o Aegent OEPIF: residential increases
	• Jay Shepherd, Counsel for School Energy Coalition
	• John Loucks, Vice-President - Corporate and Member Affairs, Electricity Distributors Association
	• George Vegh, Chair, Distribution Regulation Review Task-Force
	• Adonis Yatchew, Consultant to Electricity Distributors Association

Mar 27-12	Board staff posted an updated draft agenda for the two and a half-day Stakeholder Conference planned for March 28, 29, and 30, 2012. • Updated Draft Agenda • Attachment to Draft Agenda
Apr 5-12	The Board has issued guidance to stakeholders on issues where comments would be particularly helpful to the Board in developing a renewed regulatory framework for electricity distributors and transmitters. **Interested stakeholders are invited to file written comments by April 20, 2012** in accordance with the filing instructions set out in the letter below. • Letter
Apr 9-12	Board staff posted transcripts from the March 28-30 Stakeholder Conference. • Transcripts
Apr 24-12	Board staff has posted the written comments received by the Board by April 20, 2012. • View Comments (+)

Appendix B: Summary of Planned Consultation Activities

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
2012						
October	Stakeholder working groups established to address distribution network investment planning, smart grid, and regional planning issues			Stakeholder working group established to address both performance- and benchmarking-related issues		
	A web-cast on the "Report of the Board: A Renewed Regulatory Framework for Electricity" and next steps will be held					
November	**Staff proposal** issued in relation to asset management and capital planning filing requirements	Working group meetings			**Summary of data points and time series** needed for empirical analysis issued for distributor validation	
				Staff proposal on standards, measures, and scorecard issued	**Consultant concept paper** on empirical analyses *(including consideration for inflation and productivity)* and benchmarking issued	
December	Working group meetings		**Working Group Reports to the Board** issued: (1) Asset Redefinition; (2) Regional Planning Process	A stakeholder meeting to inform and generate ideas prior to convening the working group		
				Working group meetings on standards, measures and scorecard		
2013						
January		**Supplementary report of the Board** issued: Smart grid policy		Working group meetings (continued)	Distributor validation of data points and time series due	
	Staff proposal for consolidated capital planning filing requirements issued					
	Working group meetings					

Target	Infrastructure investment planning			The outcome based framework		Electricity distribution rate-setting
	Distribution Network Investment	Smart Grid	Regional	Performance	Benchmarking and Rate Adjustment Indices	
February	Working group meetings (continued)		**Proposed amendments to the Transmission System Code** issued **If needed, proposed amendments to the Distribution System Code** issued		Working group meetings on empirical analyses *(including consideration for inflation and productivity)* and benchmarking	
	Application filing requirements and guidelines issued setting out consolidated capital planning provisions					
March				**A Board Staff Report to the Board** on standards, measures and scorecard issued for comment	**Consultant report** on methodology, data analysis, calculations, and results in relation to the preferred approach to benchmarking issued *(consideration for inflation and productivity will inform a Stakeholder Conference in April)*	
April			**Amendments to the Transmission System Code** issued	Stakeholder meeting on performance and benchmarking related issues		Stakeholder conference on appropriate values for inflation and productivity factors
May				Written *comments due on staff report and the preferred approach to benchmarking and results*		
June				**Supplemental Report of the Board** issued describing the standards, measures and scorecard reporting associated with utility outcomes for customer service and cost performance **Consultant final report** setting out the approach to total cost benchmarking that will be used by the Board issued		**Board determination** on inflation, productivity factor, and stretch factors issued
						Application filing guidelines issued setting rate application provisions
July				**If needed, proposed amendments to the Electricity Reporting & Record Keeping Requirements** issued		**Board determination on stretch factor assignments** issued