Ontario Energy Board

Staff Discussion Paper

on the Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors

July 25, 2006

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1 Introduction

Purpose

Cost of capital to be used in adjusting rates for 2007 and beyond

In its May 11, 2005 RP-2004-0188 Report of the Board on the 2006 Electricity Distribution Rate Handbook, the Board reminded parties that it would conduct a review respecting the issues involved in establishing the applicable cost of capital.

Adjusting rates during the Board's Multi-Year Rate Plan

In addition, over 2007 to 2009, as the Board carries out several electricity distribution rate-related studies, rates will have to be adjusted on a regular basis for electricity distributors.

Staff of the Ontario Energy Board is releasing this paper to continue consultations on these two key elements of the Board's multi-year electricity rate-setting plan (the "Rate Plan"): the review of the cost of capital; and the development of a 2nd Generation incentive regulation mechanism ("2nd Generation IRM"). This Discussion Paper is one step in a larger process leading to the implementation of codes respecting cost of capital and incentive regulation. In this paper, staff is identifying its current views of the key options in relation to these issues and its preliminary evaluation of those options. This includes identifying preferred options. Staff is identifying preferred options so that parties have a sense of staff's current views and the reasons for those views. This should provide meaningful content and context for the parties' consideration. Staff's views have evolved as more information and analysis comes forward, and are expected to continue to evolve throughout this process. Staff's views do not represent the views of the Board or indicate how the Board will ultimately determine how to proceed.

Staff invites alternative perspectives from parties in order to provide the Board with a thorough analysis of the issues. In this respect, the paper is designed to inform parties and elicit discussion.

Background

Scope of Review

This review examines the parameters associated with cost of capital and factors involved in setting an adjustment mechanism for 2nd generation incentive regulation. The cost of capital review uses the benchmark 1998 paper by Dr. Cannon entitled "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario" (available on the Board's website) as the point of departure. In addition to a review of the economic and financial issues that are discussed by Cannon, this review includes an examination of the risks faced by distributors and seeks to highlight outstanding issues.

The term (1 to 3 years) and starting base (2006 rates) for the 2nd Generation IRM have already been determined and are therefore outside the scope of this project. Further, recognition for distributor diversity in 2nd Generation IRM is out of scope but may be designed into the 3rd Generation incentive mechanism (3rd Generation IRM), as appropriate.

Approach

On April 27, 2006, the Board issued a letter to interested parties describing the process that the Board is using in relation to this review of the cost of capital and the development of the 2nd Generation IRM.

The Board proposes to implement its cost of capital and 2nd Generation IRM determinations through an amendment to electricity distribution licenses. Under the Board's current thinking, the Board will amend the licences of electricity distributors to stipulate that, in determining rates for the distributor, the Board will apply the methods or techniques set out in new codes (the "Codes") that will be developed as part of this project: a Code that confirms the cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond; and a Code that establishes a simple, practical and mechanistic incentive rate adjustment mechanism for the period covered by the Rate Plan.

Board will apply the methods or techniques set out in new Codes to implement Cost of Capital and 2nd Generation IRM

On July 7, 2006, the Board commenced a proceeding on its own motion under section 74 of the *Ontario Energy Board Act, 1998* to amend the licences of electricity distributors (EB-2006-0087). This proceeding will progress in parallel with the development of the Codes.

License amendment proceeding

Development of the Codes will proceed in two phases. Phase I, which commenced on June 19, 2006, has been a staff-led consultative process on the development of principles and mechanisms to inform the Board's preparation of the proposed Codes. Formal notice and comment on the Board's proposed Codes is Phase II of the process.

Two-phased approach to development of Codes

On June 19, 2006, the Board posted on its website a draft report containing staff's preliminary proposals for both the cost of capital and the 2nd Generation IRM. Interested parties were invited to comment on this draft report. The purpose of the draft report was to provide stakeholders with a framework for discussion, including the identification of critical issues. The draft report was informed by, but in some respects departed from, the expert advice retained by staff to review both incentive rate making and derivation of cost of capital. Reports prepared by the experts retained by staff were also posted on the Board's web site: a report on the cost of capital prepared by Dr. Fred Lazar and Dr. Eli Prisman of the Schulich School of Business entitled "Calculating the Cost of Capital for LDCs in Ontario" (June 14, 2006); and a report on incentive regulation

Phase I – Staff Consultative process

prepared by Dr. Mark Newton Lowry of Pacific Economics Group, entitled "Second-Generation Incentive Regulation for Ontario Power Distributors" (June 13, 2006).

On June 20th, Board staff hosted an information session for interested parties on incentive regulation and the cost of capital. Staff also met with various stakeholder groups in June to discuss its proposals and stakeholder comments. The aim of these sessions was to facilitate common knowledge and understanding of the cost of capital and incentive regulation theory and to identify supplementary issues. Staff has prepared this paper after reviewing the reports of staff's experts and considering comments heard and received in writing from interested parties on staff's initial proposals in its draft report.

Phase II – Board Notice and Comment

The next step in this process is a technical conference, which will provide a further opportunity for comment and input. Following the technical conference, the Board will consider the views of staff and of all parties. The Board will make a preliminary determination of the appropriate approach and issue a proposed Code or Codes for notice and comment. The Board will then consider those comments in approving a final Code or Codes.

The approved Codes will set out the methods and techniques to be applied by the Board in adjusting rates for distributors for a transitional period of up to three years (depending on the distributor as explained in Section 4). This approach will replace the Board's more traditional approach of conducting annual cost of service rate hearings for all distributors.

Overview of this Paper

This paper and comments received will inform Board development of Codes

This paper outlines Board staff's current proposals and issues requiring further discussion for both the cost of capital and the 2nd Generation IRM. This paper and comments received on it will be factored into the Board's preparation of the Codes on the cost of capital and on the 2nd Generation IRM.

Guiding Objectives

In formulating these proposals, staff has been guided by the Board's objective that distribution rates be just and reasonable and also by the following objectives:

1. **Protect customers in relation to prices.** This requires a consideration of the impacts of rate adjustments while at the same time ensuring that prudently incurred costs required for the operation of the distribution system are recovered from customers.

2. **Predictability and stability**. To provide an environment where distributors and consumers are better able to plan and make decisions.

3. **Promote economic efficiency by providing the appropriate pricing signals and a system of incentives for distributors to maintain an appropriate level of reliability and quality of service**. To create an environment where the distributor is encouraged to implement operating efficiencies, while being obliged to maintain appropriate and enforceable service quality standards.

4. **Ability to raise the financing necessary to invest in distribution infrastructure to enhance service quality and reliability**. This includes allowing distributors the opportunity to

earn a reasonable return on shareholder capital and to maintain their financial viability.

5. **Minimize the time and cost of administering the framework.** Costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available. This objective could be met through a simple process that reflects the concerns of interested parties and reduces the formal process requirements.

6. **Establishing a common capital structure and incentive framework for all distributors.** The objective is to avoid imposing barriers to consolidation within the electricity distribution sector.

Organization of Paper

The paper is organized as follows. Staff's analysis of some approaches to cost of capital and 2nd Generation IRM are outlined in Section 2 and Section 3, respectively. Both sections provide a summary of associated key issues, an indication of stakeholders' comments from consultations and an account of each of the major considerations which support the proposals. Section 4 outlines in more detail how and when the adjustments to distribution rates will be implemented. Section 5 summarizes staff's current approach to cost of capital and to the 2nd Generation IRM.

2 Cost of Capital

2.1 Theory

The Cannon methodology

The Report of the Board on the 2006 Electricity Distribution Rate (EDR) Handbook of May 11, 2005 provides guidance on how electricity distributors should calculate the cost of capital. The Board Report relied primarily upon a 1998 study by Dr. W. Cannon, "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities".

Since 1999, the cost of capital for distributors has been governed by the Board's Decision with Reasons in proceeding RP-1999-0034, which established a size-related capital structure for distributors and applied the Board-approved methodology in setting the return on equity (ROE) at 9.88%. The subsequent phase-in of the Market Adjusted Revenue Requirement (MARR) and the rate freeze imposed by Bill 210 in 2002 rendered unnecessary further reviews of the cost of capital until the 2006 EDR proceedings. Table 1 and Table 2 provide the allowed ROE, capital structure and debt rates for distributors for the 2006 rate year, as described in the 2006 EDR Handbook.

Table 1: Allowed ROE

Average of 3- and 12-month *Consensus Forecasts* outlook for 10-year Government of Canada bond rates	4.75%
Average difference during April 2005 between 10- and 30-year Government of Canada bond yields (Source: Bank of Canada)	0.45%
Equity risk premium	3.80%
Allowed return on equity	**9.00%**

Table 2: 2006 Rates Capital Structure and Debt Rates

Rate Base	Deemed Capital Structure		Deemed Debt Rate (DR)
	Debt (D)	Equity (1-D)	
> $1.0 billion	65%	35%	5.8%
$250 million - $1.0 billion	60%	40%	5.9%
$100 million - $250 million	55%	45%	6.0%
< $100 million	50%	50%	6.25%

Debt and equity are the two traditional forms of investment in a corporation. Risk may be addressed through both the capital structure (i.e. the proportions of debt and equity) and through the rates applicable to each of the debt and equity components.

The cost of capital is very important for distributors since it represents about half of the revenue requirement. In any business, capital is required to acquire assets that will produce income in the future. There is always some risk that the assets will not generate enough income to recover the operating expenses, cost of assets, debt costs, as well as yielding an acceptable return to shareholders.

Distribution versus other investment opportunities

The question is what return on investment is required to invest in distribution utilities versus other investment opportunities? The answer depends on the degree of risk investors are willing to take in relation to earning a profit on their investments. If investors were not willing to accept any risk they would more likely invest in government bonds.

To incent investment in distribution utilities, what extra amount (or “risk premium”) would be needed? The riskier a business is – the higher the probability that future income will not be realized – the more likely and the more appropriate it is that capital will come from equity sources.

Over what period should investors seek a return? This too depends upon risk tolerance. Distribution utilities have relatively long-lived assets, so the relevant time period can be quite long.

Board has to consider many points of view

In setting the cost of capital the Board has to consider many viewpoints in the public interest. What cost of capital will attract enough investment consistent with the risks faced by electricity distributors? Distributors' perspectives on risk are necessarily more focused on the perceived operational risks of the business than those of investors, who equally of necessity, are interested in the risk of an investment in a distribution business as compared to investments in other similar businesses. Many of the comments received on the first staff draft report reflect these differences in perspective. In particular, the investment community indicated that a higher ROE is necessary to attract investment in distribution as opposed to competing investment opportunities. Secondly, distributors indicated the need for thicker equity in order to attract capital. Thirdly, ratepayer groups questioned whether the distribution sector faces these challenges in raising capital given the regulated nature of the businesses.

In the case of Ontario, the Board's previous reviews of cost of capital reveal a general agreement that regulated utilities are less risky than the broader market on which the rating agencies primarily focus. Beyond that, however, there is a large potential range of risk and varied opinion on the best way of representing that risk in the current circumstances of Ontario's distribution utilities. Staff has looked to the advice of experts to move from the general theory outlined here to the specific recommendations, below, for the approach to setting the cost of capital for 2007 and adjustments beyond. In addition, staff has reviewed regulatory practice in several key Canadian and United States jurisdictions.

2.2 Ontario Market Conditions and Risks to Electricity Distributors

Relatively recent transition to new regulatory regime

The cost of capital for Ontario's electricity distributors is best understood in the context of their recent history. Up until 1999 the electricity distributors were municipal organizations that were regulated by Ontario Hydro; from 1972 until 1998 the authority for this regulation was provided by the *Power Corporation Act* (PCA). In 1998, the passage of the *Energy Competition Act, 1998* gave the Board increased powers and a broader mandate, including responsibility for regulating the monopoly transmission and distribution systems for electricity. It also required municipalities to transfer the assets of these utilities to corporations established under the *Ontario Business Corporations Act*. Thus, one set of unusual challenges faced by the Ontario electricity distribution sector is the transition from one regulatory regime to another and the associated political uncertainty.

Upon becoming regulated by the Board, these corporations were deemed to have a capital structure depending on their size as measured by the rate base. There were four categories of sizes with different deemed capital structures and deemed rates applicable to debt and equity. In 2000 the Board set the allowed ROE at 9.88%. This remained the allowed ROE until 2006, when the Board changed the return to 9.00% and maintained the stratification of debt/equity by distributor size, as a proxy for risk, originally approved as part of the previous Electricity Distribution Rate Handbook. The Board also updated the size-related deemed debt rates in 2006 but the deemed capital structures were unchanged.

Government policy objectives rely on distributor sector involvement

Looking to the future, distributors may face challenges arising from government policy respecting the "culture of conservation" and "smart" metering. This is in addition to the continuous need for distributors to invest capital for maintaining, replacing and expanding their electricity distribution infrastructure.

Board staff addresses these issues and challenges in its proposals.

2.3 Approach and Components

Staff proposes ERP approach

In setting a regulated cost of capital the Board has to keep in mind two interrelated objectives: the need to ensure that distributors have sufficient ability to attract capital; and, the need to ensure that consumers are not required to pay any more in rates than is necessary to meet the capital needs and reasonable operating profits of the distributors.

In practice, there is considerable agreement that a prudent way to reflect risk in the regulated return on equity is to determine the appropriate riskless rate and add a premium (the “Equity Risk Premium” ERP) that reflects the riskiness of the regulated business. Risk can also be reflected in the capital structure (i.e. the ratio of debt to equity). Risk can be incorporated in the cost of capital through the ROE, the capital structure, or a combination of both.

Staff does not find any compelling argument that any of the ways of incorporating risk is better than the others in reflecting an appropriate cost of capital. Staff’s proposal is guided throughout by a preference to use techniques for valuing risk that are as close as possible to the risks revealed in financial markets by the market valuation of different firms and their associated cost of capital.

Staff proposes to use revealed preference of financial markets

Underlying both the cost of debt and equity is the estimation of the appropriate riskless rate. The practice to-date in Ontario and the most popular method across jurisdictions is to rely on consensus forecasts of the riskless rate. The alternative is to rely on the revealed preference of financial markets. New tools have become available in recent years to allow for the latter approach and one of them is recommended by Lazar and Prisman. This method takes advantage of new data which began to be provided by the Bank of Canada in 2004.

Staff proposes riskless rate = zero-coupon bonds

The new data are estimates of the zero-coupon yield curves that may be inferred from the traded prices of Government of Canada bonds. These are known as "forward rates". Zero-coupon bonds are bonds that do not pay any yearly interest to the holders; they merely promise to repay the holders the face value of the bond at some future date. The prices of zero coupon bonds represent the value to investors of holding the bonds to their maturity dates in the absence of any coupon returns. The inferred discount rates from these values for bonds at different maturities provide an estimate of the yield curve for riskless bonds (i.e. the schedule of yields for different periods to maturity). The appropriate riskless rate for regulated utilities is a smoothed average of these curves. Lazar and Prisman provide a simple spreadsheet mechanism that smooths the Bank of Canada data over a rolling 6 year period.

Staff proposes inputs be updated annually

Another matter that requires discussion is the issue of updating the cost of capital. A distinction needs to be made between updating: (1) the formula itself; (2) the parameters of the formula; and (3) the inputs to the formula. Staff currently proposes that only the inputs to the formula be updated annually to minimize uncertainty about changing formulae or parameters.

2.3.1 Capital structure

Staff proposes a common structure for all distributors and recommends 60% debt and 40% equity

At this time, staff proposes a common structure for all distributors. The issue then becomes what should this common structure be? Staff acknowledges the concerns that have been expressed by distributors and the investment community about the credit worthiness of electricity distributors. Based on concerns expressed related to ability to attract capital, staff's recommendation is for a split of 60% debt, 40% equity.

Included in 40% equity would be any preferred shares issued by the distributor up to a maximum of 4% of rate base.

This is a thicker common equity than for Ontario natural gas distribution utilities (which are at a debt–equity ratio of 65/35 and 64/36) but staff believes that this is justified for several reasons. The natural gas distribution industry has been regulated by the Board for decades and the risks have been examined thoroughly through the regulatory process, unlike the electricity distribution industry. As a result of this history of regulation before the Board, staff is more confident about the current state of infrastructure of the gas distributors. Staff believes that there is a need for significant expansion of investment in electricity distribution infrastructure for maintaining, enhancing and expanding the infrastructure and that this poses additional risks as compared to natural gas distributors. This is reflected in staff's recommendation for a higher proposed equity.

While there are several dimensions of risk that vary across utilities, such as load concentration, total load, etc., staff finds that there is no reasonable way to differentiate them. In other words, distributors are more alike than they are different with respect to the risks that they face, and therefore proposes a common structure for all distributors.

Figure 1 provides a schematic overview of the overall approach.

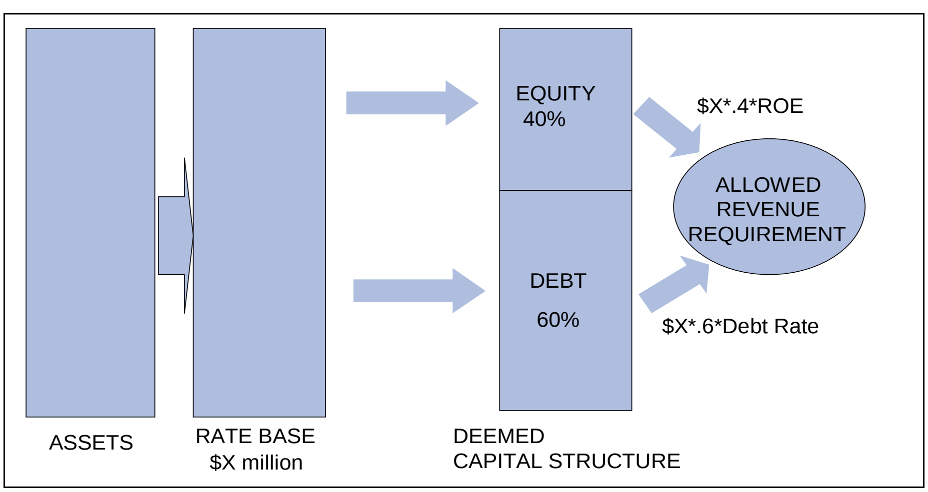

Figure 1: Capital Structure Overview

Staff is open to hearing other views on all aspects of capital structure. In particular, what would be helpful would be justification and supporting arguments for a higher equity thickness and the principles which underpin differing proposals.

Is 40% equity sufficient?

2.3.2 Equity Risk Premium (ERP)

Staff has described above the approach proposed for the riskless rate. This section concentrates on the determination of the ERP.

Three methods to determine ERP: CE; DCF; and CAPM

There are three methods in common use for the determination of the appropriate ERP. These are: the Comparable Earnings (CE) method; the Discounted Cash Flow (DCF) method; and the Capital Asset Pricing Model (CAPM). The common approach in North America appears to be to use some combination of these methods. A recent Decision of the British Columbia Utilities Commission (BCUC) preferred to exercise judgment on cases using estimates from all three methods. However, there are also jurisdictions that use only CAPM, for example, a recent Decision of the Alberta Energy Utilities Board (AEUB) endorsed CAPM as the preferred method.

Staff acknowledges that CAPM is not without well-known limitations. As determined in Alberta and previously in Ontario, these limitations are, however, far less serious than the shortcomings of CE and DCF. While of historical importance, CE has long been acknowledged to place a greater reliance on accounting definitions of earnings which leads to published values that are too easily manipulated. In the post-Enron era, this should not need emphasis. DCF for traded firms relies on projecting future cashflows and deriving the discount rate that yields the market value of equity, which is far more uncertain than attempting to specify market-based parameters. In addition, only one of the Ontario electricity distributors has equity that is traded. Using a proxy group of traded companies – an apparently similar approach to the CAPM – only compounds the problem of projecting uncertain cashflows with the problem of choosing appropriate proxies. CAPM limits the problem to the latter.

Moreover, the limitations of CAPM are not improved by introducing arbitrary weightings of ERP estimated from CE and DCF. Similarly, on *a priori* grounds, the CAPM is the common method (there are more advanced methods based on Arbitrage Price Theory) that has the most sound theoretical basis in the financial literature.

The CAPM is sometimes criticized because estimates of ERP using CAPM vary with a number of factors. This is to be expected from a measure of risk that tracks actual market risk which varies over time and in relation to a range of factors.

Is CAPM appropriate?

Staff suggests using only the CAPM to set ERP. It would be helpful to staff and the Board to understand the arguments and principles that parties believe support an alternative method for setting ERP.

2.3.3 Return on Equity (ROE) Scenarios

The ROE is based on the ERP, the riskless rate and the parameters used to calculate them.

The two elements of the CAPM estimate of ERP are: the average market return and the "beta", which is the measure of the relative risk of the specific assets under evaluation (in this case distribution companies). There are three main factors to consider in relation to these elements:

- ➔ the sample of firms from which to estimate the average market return;
- ➔ the sample of firms from which to estimate the beta; and

➔ the relevant time frames for each.

Four ERP scenarios based on proxy group membership and short- long-term perspectives

In order to better assist the Board in its deliberations on these factors, staff has developed four scenarios for the ERP which are presented in the table below. The table shows results from two groups of companies that could each serve as a proxy for Ontario electricity distributors: companies listed on the Toronto Stock Exchange (TSE) that are engaged, at least in part, in the electricity sector; and, TSE companies that are rate-regulated (including those that are also in the electricity sector). The CAPM beta is estimated for each of these groups over two periods (one year and 5 years) and an applicable ROE derived by applying either a short term or long term average market return (5 or 10 years) and riskless rate (one or 15 years). The riskless rate is based on the zero-coupon bond yields. While there are a range of periods for those bond yields, staff has focused on using the shortest and longest terms available (1 year and 15 years). Appendix A provides the detailed calculations and the companies included in each proxy group.

Table 3: ROE Scenarios

	SHORT-TERM		**LONG-TERM**	
	Electric	**Rate Regulated**	**Electric**	**Rate Regulated**
Average market return period	60 months	60 months	120 months	120 months
β period	52 weeks	52 weeks	60 months	60 months
Riskless period	1 year	1 year	15 years	15 years
Resultant ROE (including 50 bps)	**6.61%**	**6.65%**	**7.50%**	**8.37%**

Staff proposes long-term view of rate regulated

Although four scenarios are shown, each of which is plausible, staff believes that a longer-term approach is preferable given the long-term nature of distribution system investments. Staff also believes that the appropriate proxy group is all rate-regulated companies because staff has assumed that these companies have similar risk profiles and therefore may compete for the same capital. The outcome of this methodology can be compared to the outcome from applying the existing Cannon methodology as shown in Appendix B.

50 bps premium

The ROEs in Table 3 include 50 basis points (bps) because the Board has included this in previous orders as an implicit premium for floatation and transaction costs.

Incentive for investment?

The necessity to raise significantly higher levels of capital for infrastructure upgrading and expansion may justify an additional premium to the ROE for electricity distributors. Staff invites comments as to whether a premium in the range of 50 to 150 bps would be required to provide an incentive for new infrastructure investment. If this were the case, and using the long-term, rate regulated scenario result from Table 3 above, the existing rate base as of 2006 would earn a return of 8.37% while new distribution infrastructure added to rate base in 2007 and beyond would be at an ROE of between 8.87% to 9.87%.

Comments on all aspects of return on equity are invited.

2.3.4 Debt Rate

Staff makes a distinction between affiliated debt and third party debt. Staff also makes a distinction between new and existing debt.

New affiliate debt at riskless rate plus bond spread

Staff believes that the deemed cost of new affiliated debt should be the riskless rate plus a bond market spread. This is the rate that would be applied to affiliate debt or to the proportion of the rate base allocated to debt. Staff has already noted its preference for a riskless rate based on the revealed judgment of the market over expert forecasts of the market. For the bond market spread, staff accepts the recommendation of Lazar and Prisman to base the spread on the difference between the average rate of a suitable sample of corporate A/BBB bonds and the average rate for Canada bonds of the same term structure.

For new third party debt the actual debt rate would be used.

New 3rd party debt at actual

All existing affiliate and third-party debt would be at the previous Board-approved rate.

Existing at Board approved

As a general principle, staff believes that the term of debt should try to match the life of the assets that are to be acquired with that debt. Thus, for an industry with long-lived assets, the majority of debt should be long term. Nevertheless, some short term debt is needed to provide cashflow stability. There are no general rules that provide guidance. Staff offers as an option that short-term debt, needed to finance working capital, be deemed to be 8% of rate base. This is based on staff's review of Hydro One Distribution's lead-lag study filed in its 2006 EDR rate case (Table 1 on Hydro One's RP-2005-0020/EB-0378, Exhibit D1, Tab 1, Schedule 1, Page 2 of 5).

Staff suggests ST debt be deemed at 8% rate base

Concerns have been expressed by distributors about access to capital. However, to date, very few Ontario electricity distributors have attempted to issue debt in financial markets. Those that have do not appear to have had difficulty in doing so; nor does there appear to be difficulty in attracting bank financing for capital investments. Staff invites parties to demonstrate if this has not been the case. This will be helpful to the Board in determining whether staff's suggestions on the capital structure and risk premium are appropriate or require adjustment.

Access to capital

Staff is sensitive to the likelihood of substantial financing needs for the introduction of smart metering. Staff is therefore proposing an adjustment to all distributors' fixed distribution rates (see section 4.3.1 entitled "Allowance for Smart Meter Implementation") to ensure financing does not impose constraints to the smart metering program.

Incremental smart meter funding

Staff invites comments on alternate proposals on the issue of debt rate and supporting rationale for these.

3 Incentive Regulation

3.1 Theory

Staff was informed by the advice of Dr. Mark Newton Lowry, of the Pacific Economics Group ("PEG") in developing this proposal. Dr. Lowry's report entitled "Second Generation Incentive Regulation for Ontario Power Distributors" ("PEG Report") provides a comprehensive discussion of the criteria for the design of regulatory systems, the advantages of incentive regulation over traditional cost of service regulation, the major issues in the design of an incentive plan, and a discussion of plan options for Ontario.

The approach suggested below is independent of the development of 3rd Generation IRM.

3.2 Objectives of 2nd Generation IRM

The objectives of the 2nd Generation IRM are to: provide regulatory certainty to distributors during the Rate Plan as several rate-related studies are carried out; drive efficiency improvements in the distribution sector; and lay a foundation for the 3rd Generation IRM.

Transitional incentive regulation

As such, the proposed 2nd Generation IRM is a transitional methodology, and not an end-state in itself. The Board needs to put in place a formulaic rate adjustment method that will return distributors to incentive regulation, without creating any major hardships for them or for their ratepayers. As outlined in the Rate Plan, the Board will rebase rates for each of the distributors over a period of years. Staff believes that its current proposal is an effective transitional methodology that balances short-term efficiency, simplicity, and time management to allow the Board to approve just and reasonable rates.

3.3 Approach and Components

3.3.1 Annual Proxy Adjustment for Cost of Capital – K-factor

Staff suggests a staged implementation of cost of capital

Staff suggests that during 2nd Generation IRM, distribution rates be adjusted by an incentive formula that would include, as one adjustment factor, recognition of changes to the existing capital structure and ROE. Those distributors whose rates will be rebased will have the proposed cost of capital method applied to their revenue requirements. Until rates are rebased, the adjustment factor would be applied to adjust their revenue requirements.

Staff suggests the creation of two separate "K-factor" adjustments to rates to account for the change in ROE and capital structure of distributors from what is currently reflected in rates.

2007 adjustment for change in ROE

First, the "K-factor" that staff proposes for 2007 would numerically approximate the adjustment for changes in ROE. It would not adjust for any changes to debt rates or the capital structure. In addition, staff proposes that the K-factor adjustment in 2007 only be applied if the newly calculated ROE differs by more than 10 basis points from the 2006 Board-approved ROE of 9%. Staff notes that its proposed inflation proxy tracks some changes in market returns and therefore, the K-factor adjustment for ROE would be a one-time adjustment in 2007 (i.e., there would be no additional adjustments throughout the 2nd Generation IRM term for changes to ROE).

2008 adjustment for change in capital structure

Second, for distributors that are still subject to the 2nd Generation IRM (i.e., those that do not have their rates rebased in 2008), the "K-factor" that staff proposes for 2008 would numerically approximate the adjustment necessary to move a distributor from its current capital structure (i.e., one of the four listed in Table 2 on page 8 of this report) to the proposed common capital structure. It would not adjust for any changes to debt rates. Distributors rebasing their rates in 2008 would have all cost of capital changes dealt with through their rebasing application rather than through a K-factor.

Staff does not propose any adjustments in 2009 through the K-factor.

The 2007 and 2008 adjustments would be calculated as described in Appendix C.

Staff has carried out some preliminary calculations on this proposed approach to calculating "K". Based on these calculations the 2007 K-factor could be between -2% and +2%, depending on the Board's determination of the 2007 ROE. The 2008 K-factor to adjust for capital structure change could be between -1% and -3%.

Exceptions

Staff proposes that distributors that selected a zero ROE, or a ROE in 2006 rates below the allowed ROE of 9%, be exempted from K-factor adjustment in 2007. That is, the value for the K-factor in 2007 may be zero for distributors that (a) have an allowed ROE of zero, or (b) have an allowed ROE which is less than the Board-approved maximum of 9% ROE for 2006.

3.3.2 Term and Starting Base

Term of up to 3 years, and starting base of 2006 rates

As indicated in the Board's April 27, 2006 letter announcing this project, the term of (up to 3 years) and starting base (2006 rates) for the 2nd Generation IRM have already been determined in the Board's multi-year rate setting plan for electricity distributors. Some parties commented that the 2006 rates were based on 2004 and therefore the 2nd Generation IRM should be adjusted in 2007 for three years (2004 to 2007) and not one year (2006 to 2007). Staff does not believe that this is appropriate. The

2006 test year rates were set based either on a historical test year or on a forward forecast year and are determined by the Board to be just and reasonable. To adjust the 2007 rates for three years would suggest that the 2006 rates and associated revenue requirements are not just and reasonable. Therefore, staff does not propose to escalate the 2006 EDR historical year filers to a current test year.

Further, there is no expectation that any distributors' rates will be rebased prior to implementing the incentive adjustment for new rates effective May 1, 2007. The term of 3 years is not for all distributors. Some whose rates will be rebased in 2008 will have this mechanism in place for 1 year. Others whose rates are rebased in 2009 will have this mechanism in place for 2 years, and the remaining distributors will have their rates rebased in 2010 which results in this mechanism being effective for at most, three years.

3.3.3 Form

Staff proposes price cap approach

Staff proposes the Board retain a price cap form of adjustment mechanism for electricity distributors. The Board deliberated on different forms of incentive regulation extensively in its RP-1999-0034 proceeding which dealt with Performance Based Regulation for licensed electricity distributors, and in its RP-1999-0017 proceeding in response to Union Gas Limited's application for rates and other charges in accordance with a performance based rate mechanism. Both proceedings resulted in Board adoption of price cap regulation.

With regard to alternative mechanisms, at this time, staff believes that the data and modeling requirements necessary to establish a price cap approach within a yardstick or benchmarking framework for the Ontario electricity distribution sector are prohibitive at this time. Yardstick or benchmarking regulation simply uses information on industry, sub-industry, or peer group cost performance to establish a benchmark price (i.e., rate) for each firm in that group. Some form of benchmarking and/or comparators and cohorts analysis is anticipated in 3rd Generation IRM. Revenue cap plans make distributors indifferent to gains and losses from demand fluctuations; however, they transfer to customers the risk of volume fluctuations thus contributing to price uncertainty. At this time staff does not believe that the benefits to distributors outweigh the risks to consumers.

The price cap continues to be a simple approach that will, along with the implementation of mandatory service quality requirements as described below, provide balanced incentives for efficiency improvements and the maintenance of adequate service quality over the course of the 2nd Generation IRM.

3.3.4 Price Escalator

GDP-IPI as a measure of inflation

A survey of incentive regulation formulas approved in other jurisdictions shows that the Gross Domestic Product Implicit Price Index (GDP-IPI) is the prevalent inflation proxy used by North American regulators for gas, electric, and telecom utilities. Dr. Lowry provided a summary of X-factors with implicit input price differentials and productivity offsets approved by North American Regulators for gas and electric utilities on page 55 of the PEG Report. The summary includes the inflation measures used in those jurisdictions. Although a macroeconomic measure, the GDP-IPI is published by a trusted source, is readily available and is likely more easily understood by the public than an industry-specific measure would be.

With regard to use of CPI rather than GDP-IPI, staff agrees with Dr. Lowry that GDP-IPI is preferable to the CPI because it tracks a more relevant set of goods and services used as inputs for production by businesses, including electricity distributors. CPI tracks the prices of consumer goods and services, whereas GDP-IPI is a broader measure of inflation that covers other relevant sectors of the economy such as capital equipment. Therefore, staff proposes that a GDP-IPI be used as the inflation proxy for the 2nd Generation IRM.

Staff may review and refine, where appropriate, the IPI methodology employed in the Board's 1st generation PBR for consideration in the 3rd Generation IRM. As discussed by Dr. Lowry in the PEG Report, an industry-specific input price index tracks industry input price fluctuations better than an economy-wide measure. Therefore, it may better mitigate significant gains and losses that might result from the failure of a macroeconomic index to track industry input price inflation. Both electricity transmission and distribution are capital intensive and are therefore sensitive to changes in the cost of funds, and this pattern of fluctuation can differ from that of an economy-wide measure for extended periods.

In the interim, staff is currently of the view that the GDP-IPI approach is less controversial and easier to implement over the next three years while a number of important rate-related studies are carried out. Only one index needs to be obtained and the only calculation necessary will be the growth rate of the index.

Canada GDP-IPI for final domestic demand

Staff considered four potential choices from the set of GDP-IPI indices available from Statistics Canada: Canada GDP-IPI; Ontario GDP-IPI; Canada GDP-IPI for Final Domestic Demand; and Ontario GDP-IPI for Final Domestic Demand.

Ontario GDP-IPI data are available by late April. Distribution rate adjustments need to be in place May 1st. Therefore, the Ontario GDP-IPI data are not available in time for the Board's distribution rate adjustment process. Canada GDP-IPI data are published for the previous year and 4th quarter by February 28th. This timing is suitable. Of the two national indices, staff rejects the Canada GDP-IPI because it includes consideration of inflation in the prices of crude oil and natural gas and other price-volatile exports. These are important to Canada, but are not important inputs to “wires-only” electricity distributors in Ontario. The Canada GDP-IPI for final domestic demand excludes these inputs. Therefore, staff proposes that that the Canada GDP-IPI for final domestic demand be used. The average annual growth rate in this index for the period between 2000 to 2005 has been 1.77%.

Staff proposes use of 4th quarter data for GDP-IPI

For May 1st implementation, rate adjustments should be completed by the end of March 2007. With this timing, staff currently proposes that the 4th quarter (calendar annual) GDP-IPI data be used for the rate adjustment. The 4th quarter data for the previous year uses available historical data that is relatively current. It also corresponds with distributor fiscal year end (for accounting and regulatory reporting). Therefore, it would be possible to use this data in any potential analyses of cost of service “rebasing” applications, and to integrate this data into rebased rates based on a distributor’s annual data.

Statistics Canada is acknowledged for the theoretical soundness and the data integrity of its data collection and computation methods. Staff understands that published statistical data may be subject to revision by Statistics Canada. However, staff notes that data revisions – particularly for common macroeconomic indicators – are generally limited in magnitude.

Acknowledging that revisions will occur, staff believes it is appropriate to factor them into the update of the price cap index. This is most easily done by taking the GDP-IPI as a price index time series rather than by relying solely on the annual change in the series each year. Revisions beyond one year are generally infrequent and small in magnitude. Therefore, staff currently proposes to limit provision for adjustments to only the prior year.

3.3.5 X-factor

Staff proposes an X-factor of 1%

Staff believes that to simply allow for pure inflation growth in the price cap formula would not create sufficient incentives to distributors for efficiency improvements. However, since 2nd Generation IRM is of a transitional nature, staff does not propose to develop an X-factor calibration that attempts to explicitly consider the productivity capabilities of each individual electricity distributor along with a stretch factor. Instead, staff is relying on the deliberations on these issues carried out in numerous North American jurisdictions to provide relevant precedents for this 2nd Generation IRM.

The PEG Report details how X-factors based on indexing research typically include consideration of an *input price differential* (may be computed using Canadian input price trends), a *productivity differential* (may be the difference between a proxy for a total factor productivity (TFP) trend of Ontario's power distribution industry and the multi-factor productivity (MFP) trend of the Canadian economy), and a stretch factor.

Like the selection of the inflation measure, the selection of the X-factor is, for 2nd Generation IRM, a function of simplicity and transparency. Informed by Dr. Lowry's observations in the final section of the PEG Report, staff proposes that distributors be subject to a 1% X-factor for the duration of the 2nd Generation IRM. The X-factor precedents summarized on page 55 of the PEG Report suggest 1% as a reasonable reflection of relevant input price and productivity trends. Staff believes that the proposed Canada GDP-IPI (Final Domestic Demand) and 1% X-factor together should reasonably track industry unit costs over the short-term of the 2nd Generation IRM.

Is an X-factor of 1% appropriate?

Where alternative methods for setting the X-factor are proposed, it would be helpful to staff and the Board to understand the underlying rationale and principles which support this alternate approach, as well as an indication as to whether the Board's objective of a simple 2nd Generation

IRM rate adjustment mechanism that can be applied to all distributors, is met,.

3.3.6 Contingencies and mid-term issues

Z-factors

Z-factors allow adjustment for unusual events beyond the control of the distributor's management. Examples include changes in regulation, changes in accounting or tax rules, and natural disasters. Z-factors are also appropriate in the recovery of additional approved costs outside of the rate adjustment mechanism framework (such as regulatory assets, rate adders, or CDM costs). Many comments identified the need for an IRM plan to provide for Z-factors.

Staff proposes limited Z-factors

Staff proposes that, to the extent possible, an incentive regulation scheme should limit reliance on Z-factors to well-defined and well-justified cases only. Given the varied and relatively short period of application of the 2nd Generation IRM (only 1 year for some distributors, and a maximum of 3 years for others), staff currently proposes that Z-factors be limited to the examples listed above.

Eligibility criteria

In order for costs to be considered for recovery in a Z-factor, staff proposes that the costs satisfy all four tests set out in Table 4, below.

Table 4: Z-Factor Eligibility Criteria

Criteria	Description
Causation	The cost must be clearly outside of the base upon which rates were derived.
Materiality	The costs must have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Inability of Management to Control	To qualify for Z-factor treatment, the cost must be attributable to some event outside of management's ability to control.
Prudence	The cost must have been prudently incurred. This means that the distributor's decision to incur the cost must represent the most cost-effective option (not necessarily

	least initial cost) for ratepayers.

Materiality

Staff proposes that materiality thresholds be established for 2nd Generation IRM. Specifically, and consistent with the 2006 EDR Handbook: for expenses, the materiality threshold would be 0.2% of total distribution expenses before taxes; and for capital cost recovery, the materiality threshold would be 0.2% of net fixed assets.

Consistent with guidelines established for 1st Generation PBR, staff proposes that when a distributor applies for disposition of these costs, it should be required to submit evidence that the costs which were incurred meet the four criteria outlined above in its application.

Staff proposes no off-ramps

With regard to pre-defined off-ramps, due to the varied and relatively short period of application of the 2nd Generation IRM, staff does not believe that there is a need to include any provision to allow distributors to exit the 2nd Generation IRM.

3.3.7 Earnings sharing

Staff proposes no earnings sharing

Staff does not propose an earnings sharing mechanism (ESM) be part of the 2nd Generation IRM as this is consistent with the Board's policy coming from the Natural Gas Forum, as articulated in the Board's March 30, 2005 report entitled "Natural Gas Regulation in Ontario: A Renewed Policy Framework". One of the reasons for that policy decision is that it is thought to reduce the distributor's efficiency incentives.

3.3.8 Service Quality

Service quality provisions are an important consideration in incentive regulation plan design. Definitions and reporting requirements of electricity distribution service quality indicators (SQIs) and the minimum standards set for them are laid out in Section 15, entitled Service Quality

Regulation, of the 2006 EDR Handbook. For convenience, the list of the SQIs that distributors are required to measure and report on is provided in Table 5, below.

Table 5: Service Quality Indicators in the Handbook

Customer Service	Service Reliability
Connection of new services Underground cable locates Appointments Telephone accessibility Written response to enquiries Emergency response	System average interruption duration index System average interruption frequency index Customer average interruption duration index

Distributors have been reporting their performance on these indicators since 2000. Reporting is currently made annually of monthly and annual results under the Board's Electricity Reporting and Record-keeping Requirements (RRR). Some audits of service quality have been conducted and distributors' performance during the period 2002 to 2004 was reviewed as part of the 2006 EDR applications.

Staff recommends resumption of SQR review and that indicators and standards be in the Distribution System Code

Board staff recommends that the Board resume its SQR review to finalize any further appropriate refinements to the Board's SQR regime. Further, staff proposes that the resultant indicators and associated performance standards be implemented by means of an amendment to the Board's Distribution System Code.   This approach is consistent with that taken by the Board in the natural gas sector, where the Board recently amended the Gas Distribution Access Rule to require natural gas distributors to meet mandatory SQRs. Staff believes that implementation of the refined SQR regime should be as soon as possible.

Staff believes that making the SQR regime mandatory through the Distribution System Code will effectively discourage distributors from short-term reductions in maintenance expenditures and capital investments that will affect quality of service.

3.3.9 Reporting and Data Requirements

At this time, staff does not propose any additional reporting requirements for 2nd Generation IRM beyond that contemplated by staff's service quality proposals outlined above.

4 Implementation

The Board's Multi-year Rate Plan

Earlier this year, the Chair of the Ontario Energy Board announced that the Board has established a multi-year electricity distribution rate setting plan (the "Rate Plan") for the years 2007 to 2010.

The elements of the Rate Plan and certain key milestones are set out in Table 6, below. The full plan, including the tentative schedule for rate years 2007 through to 2010, is available on the Board's website.

Table 6: Projects in the Board's Multi-Year Rate Setting Plan

Projects that are part of the multi-year rate setting plan		
1	Cost Allocation	October 2006 to February 2007
2	2nd Generation Incentive Mechanism	March 2006 to September 2006
3	Cost of Capital	April 2006 to October 2006
4	Comparators and Cohorts – Phase 2	June 2006 to March 2007
5	Distribution Rate Design Paper (Smart Meter Rate Design)	January 2007 to June 2007
6	Asset Management, Depreciation and Working Capital	March 2007 to July 2007
7	Line Losses and Distributed Generation	September 2007 to March 2008
8	3rd Generation Incentive Mechanism	March 2007 to July 2008

The Board needs to meet its Rate Plan commitments for a review of methodologies such as depreciation, cost of capital, rate design, etc. In addition, under the Rate Plan the Board needs to implement an incentive mechanism, which has as its foundation the 2006 EDR cost of service approved revenue requirement. Several processes are happening concurrently and distribution rates must continue to be set on a regular basis.

Figure 2 provides an overview of these processes. In 2007, all distributors will be subject to a formulaic adjustment for cost of capital and the incentive mechanism. Beginning in 2008, the Board will divide distributor rate rebasing reviews into three yearly tranches (i.e., ~30 distributors per year starting in 2008). The rates of 1/3 of the distributors will be subject to the 2nd Generation IRM for three years (2007 to 2009), the rates of 1/3 of the distributors will be subject to it for two years (2007 and 2008), and the rates of 1/3 of the distributors will be subject to it for one year (2007). As a number of rate-related studies and methodologies are reviewed and completed, the implementation of new methodologies will occur at the regularly scheduled interval for the distributors.

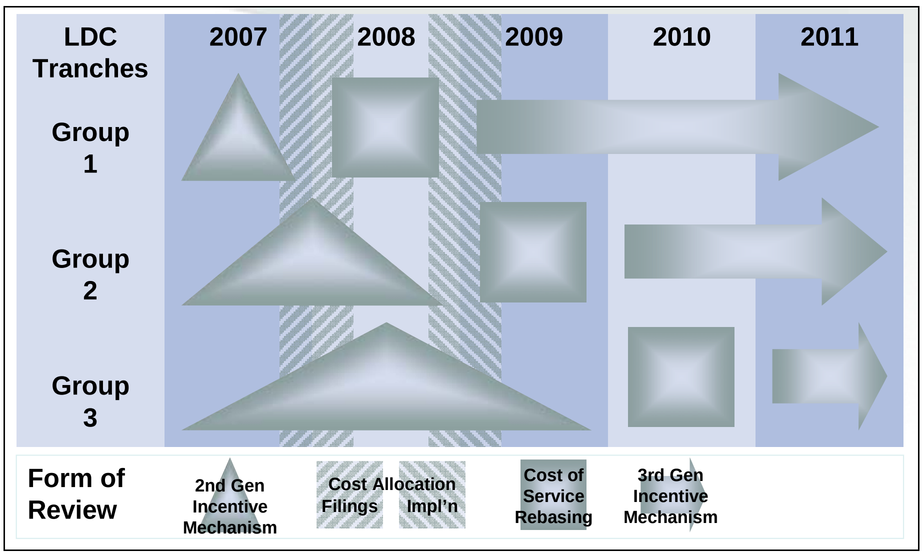

Figure 2: The Board's Multi-Year Rate Setting Plan

4.1 Determination of Rate Plan Groupings

Three tranches for the Rate Plan

Staff will soon commence a study to design a process to select distributors for rate rebasing in each of 2008, 2009, and 2010.

Criteria that staff may consider recommending to the Board for the selection process include, but may not be limited to, the following:

- Comparator and cohort information screening (e.g. costs and rates);
- Urgency of cost allocation issues;
- Prior direction in a Board decision;
- Need and ability to implement new rate design; and
- Financial viability and realized earnings (e.g., significant over/under).

The Board will hold stakeholder consultation on this design process. The aim is for the Board to be able to announce in March 2007, at a minimum, the first grouping of distributors to be rate rebased for 2008.

4.2 Integrating Cost of Capital and Incentive Regulation

Cost of capital will be addressed in two parts: first, during the incentive period between 2007 and 2009 some cost of capital adjustments would be made as described in section 3 of this report; and second, as part of the rate rebasing process that begins in 2008, distributors would have their cost of capital set in accordance with the approach which has been described in section 2.

4.3 How rate adjustments will be determined

Figure 3, below, summarizes what is in and what is not in electricity distribution rates based on 2006 rate orders. The block on the left shows what is in distribution rates and the right-side denotes other items that are not included in customer-class rates.

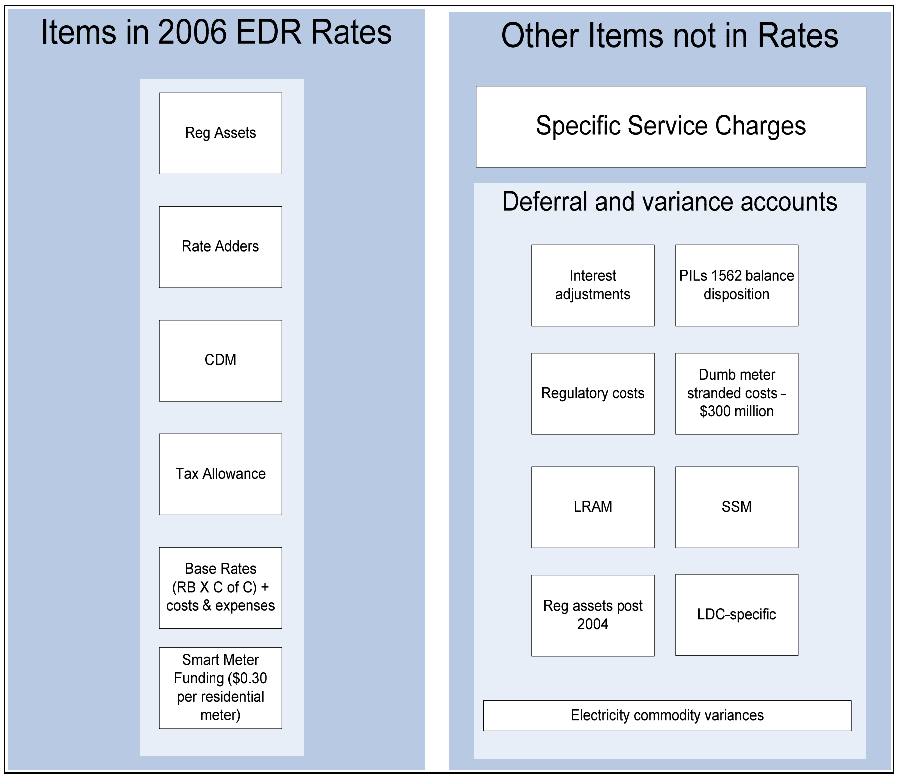

Figure 3: What's In and What's Outside of Electricity Distribution Rates

4.3.1 Allowance for Smart Meter Implementation

An amount was added in 2006 rates for smart meter implementation in order to provide "seed money" to distributors for their investment requirements and to help smooth rate shock to consumers. In its January 26, 2005 proposed implementation plan on smart meters to the Minister, the Board estimated that these costs may range from $2.00 to $4.00 per customer installation, per month.

Staff proposes increases to smart meter rate adder

Many parties expressed concern that further consideration be given to anticipated growth in smart meter costs to distributors. Staff assumes that the current rate riders for smart meter implementation will continue. Staff currently proposes an increase in 2007 of $1 to the fixed distribution rate of distributors currently working to achieve the government's target of smart meter installations (800,000) for the end of 2007 (i.e., Toronto Hydro-Electric System Limited, PowerStream Inc., Enersource Hydro Mississauga Inc., Veridian Connections Inc., Hydro Ottawa Limited, Horizon Utilities Corporation, Newmarket Hydro Ltd., Milton Hydro Distribution Inc., and Chatham-Kent Hydro Inc). Similarly, staff currently proposes an increase in 2007 of 30 cents to the fixed distribution rate of the remaining distributors that will have obligations to meet the government's 2010 target for smart meter installations.

4.3.2 Conservation and Demand Management (CDM)

Electricity distributors are an important part of the government's plan to bring about a culture of conservation. The Ontario government has established its policy direction for the coordination and funding of electricity distributor delivery of CDM activity in the province. The Ontario Power Authority has been directed to assume responsibility to organize the delivery and funding of CDM programs through distributors and other parties in Ontario after September 30, 2007.

Incremental CDM funding through rates for May to September 2007

When the new distributor coordination and funding model is up and running, distributors may enter into contracts with the OPA to receive funding. Until the new model is operational, distributors may apply to the Board for incremental CDM funding through distribution rates. Staff proposes that distributors be required to reflect in their applications to the Board consideration of input from the OPA on the OPA's plans, processes, and CDM activities.

Staff proposes that CDM-related costs which are to be recovered through distribution rates (i.e., any new spending on CDM, revenues from recovery of a lost revenue adjustment claim, or a shared savings claim) be dealt with separately from the 2nd Generation IRM rate adjustment.

4.3.3 Treatment of Taxes

Staff suggests that a distributor's allowance for taxes (whether PILs or actual taxes) be adjusted by the proposed price cap index.

Staff notes that these allowances currently include provision for income tax, Ontario capital tax, and large corporation tax. Staff considered whether only the income tax portion of taxes should be subject to the price cap index; however, staff now considers that isolating this portion from the other tax allowances is not necessary. The large corporation tax was repealed retroactive to January 1, 2006; however, it remains in 2006 rates and instructions have not yet been given for removal or booking to a deferral account of the repealed tax amount (as required by the 2006 EDR Handbook and prior methodology). Until then, it does not seem practical to try to extract this amount from rates before applying the index formula. Also, allowance for Ontario capital tax is relatively small compared to the allowance for income tax and therefore need not be shielded from the index.

As discussed in Section 3.3.6 on Contingencies and mid-term issues, staff proposes that unanticipated and material changes in tax rules during 2nd Generation IRM be treated as a Z-factor.

4.3.4 Deferral and Variance Accounts

Consistent with its proposal on Z-factors, staff proposes that, to the extent possible, an incentive regulation scheme should limit reliance on creation of new deferral accounts during the term of the scheme to well-defined and well-justified cases only. Z-factor rules should govern need for, and treatment of deferral accounts.

Staff proposes that deferral and variance account dispositions be dealt with at rate rebasing.

4.3.5 Application of the Price Cap Index

Staff proposes that its proposed price cap index be applied uniformly across all customer classes and to both the monthly fixed rate and volumetric rate, including taxes.

Staff proposes index be applied to rates, including taxes

The index would not be applied to specific service charges as the Board recently completed a generic review of these charges.

There are a number of components to distribution rates that will need to be extracted from rates before the index is applied. This includes the smart meter amount, regulatory assets amounts, rate adders, and CDM amounts.

This “de-construction” of 2006 rates is conceptually illustrated in Figure 4, below.

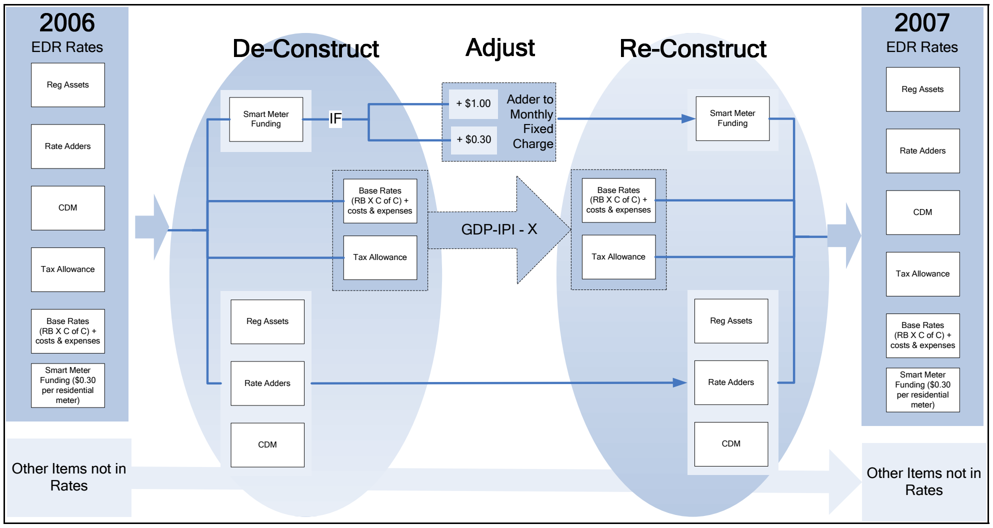

Figure 4: Conceptual Diagram of 2007 Rate Adjustments

After adjusting base rates and taxes with the price cap index and increasing the smart meter rate adder, rate elements would be “re-constructed” to derive 2007 rates. That is, the appropriate rate adders would be layered in after the new base rates have been calculated.

The practical implementation of this approach using the 2006 rates as a point of departure may mean that some of this de-construction could occur at the base revenue requirement level. Regardless, the resultant monthly fixed rate and volumetric rate (both including taxes) for all customer classes will have been adjusted uniformly by the price cap index amount. That is, if the price cap index is 1%, then the index will be applied so that the rates, including taxes, will all be adjusted upwards by 1%.

4.4 Looking Forward to 3rd Generation IRM

Staff is working on details for the 2008, 2009, and 2010 rebasing reviews, as outlined in the Rate Plan, that will occur before the start of the 3rd Generation IRM. Staff proposes the following for planning purposes:

- the review will be based on a forward test-year cost of service filing;
- benchmarking evidence may be used as an input to the review;
- the benchmarking method may differ from the current comparators and cohorts approach; and
- benchmarking may be applied to the proposed costs in any forward test year as well as to costs in recent historical years.

Staff agrees with Dr. Lowry that the timing of maintenance expenditures, replacement capital investments, and other expenditures that are made periodically are issues of mounting interest in incentive regulation schemes.

Minimum filing requirements

On July 17, 2006, staff issued for comment its draft proposal on the minimum filing requirements for electricity transmission and distribution rate applications and leave to construct projects. This includes specific instructions for the minimum amount of information the Board requires to process and review electricity distribution rate applications. The proposed requirements for cost of service filings for rate adjustments would apply in the rate rebasing year between 2nd Generation IRM and 3rd Generation IRM. The chapter on the 2nd Generation IRM will be drafted later this year to be consistent with the Board's Code developments related to cost of capital and 2nd Generation IRM. At that time, a draft of the filing requirements will be distributed for comment.

5 Summary of Staff's Current Proposal

5.1 Cost of Capital

Table 7: Cost of Capital Summary

	% of Rate Base	Return
Debt		
Long-term Debt	Actual percent of rate base (52%)	New third party – market rates New affiliate - riskless rate plus bond market spread Existing affiliate and third party as approved
Short-term Debt	8% of rate base	Board approved short-term rate for variance and deferral accounts (1 year)
Total Debt	60% rate base	Weighted average of LT and ST debt rates
Equity		
Total Equity	40% rate base (including max 4% preferred shares)	For common, riskless rate plus ERP updated annually. For preferred, as approved
Total	**100%**	**Weighted average of debt and equity rates**

5.2 Incentive Regulation

The following formula will be used to adjust each electricity distributor's distribution rates in the years 2007, 2008, and 2009 (as applicable depending on which tranche the distributor is in):

$$\%\Delta P = K + \%\Delta GDPIPI - X + Z$$

Where:

- Δ P is the annual percentage change in price;
- K is the adjustment for cost of capital in 2007 (ROE) and in 2008 (structure);
- Δ GDP-IPI is the percentage change in the Canada GDP-IPI for final domestic demand; and
- X is the 1% adjustment with implicit input price differential, productivity differential, and stretch factor; and

- Z may allow for adjustment due to unusual events and additional Board-approved costs outside of the formula.

Table 8: 2nd Generation IRM Summary

Mechanism Component	Staff Proposal
Adjustment for cost of capital (K-factor)	Percentage based on change in ROE (2007) and capital structure (2008)
Base	2006 Rates
Form	Price Cap
Term	*Up to* 3 years (per Rate Plan)
Price Escalator	Canada GDP-IPI (Final Domestic Demand)
Productivity Requirement (X-factor)	1%
Contingencies (off-ramps and Z-factors)	Z-factors limited
Earnings Sharing	None
Service Quality Requirements	To be enforceable as a condition of licence
Smart Meter Funding	Adder to the fixed rate
Conservation & Demand Management	On application

Appendix A: Detailed Calculations of Cost of Capital Scenarios

All Rate-Regulated

Shaded rows indicate firms not included in electrics group	Equity %	Short-term: Beta - 52 weeks Beta	Short-term: Unlevered after tax	Long-term: Beta - 60 months Beta	Long-term: Unlevered after tax
ATCO	47.8%	0.54	0.32	0.34	0.20
Canadian Utilities	42.9%	0.32	0.17	0.28	0.15
Coast Mountain Power Corp	98.4%	0.10	0.10	-0.43	-0.43
Enbridge Inc	33.9%	0.66	0.29	0.09	0.04
Maxim Power Corp	51.8%	0.50	0.31	0.74	0.46
Pacific Northern Gas	45.9%	0.36	0.21	0.59	0.34
TCPL	31.8%	0.48	0.20	0.14	0.28
Fortis	32.9%	0.58	0.25	0.27	0.12
TransAlta Power	52.6%	-0.23	-0.15	0.44	0.28
Canadian Hydro Developers	59.2%	0.76	0.53	1.10	0.76
Manitoba Telecom Services Inc	58.1%	0.12	0.08	0.52	0.36
TELUS Corp	59.9%	0.51	0.36	1.61	1.13
Averages	51.0%	0.39	0.22	0.47	0.29
Levered avg (60:40)			0.44		0.57
Market Return			8.09%		10.06%
ERP			1.50%		2.86%
Riskless rate			4.65%		5.01%
ROE			6.15%		7.87%
plus flotation & transaction cost			6.65%		8.37%

Electrics

	Equity %	Short-term: Beta - 52 weeks Beta	Short-term: Unlevered after tax	Long-term: Beta - 60 months Beta	Long-term: Unlevered after tax
ATCO	47.8%	0.54	0.32	0.34	0.20
Canadian Utilities	42.9%	0.32	0.17	0.28	0.15
Coast Mountain Power Corp	98.4%	0.10	0.10	-0.43	-0.43
Maxim Power Corp	51.8%	0.50	0.31	0.74	0.46
TCPL	31.8%	0.48	0.20	0.14	0.28
Fortis	32.9%	0.58	0.25	0.27	0.12
TransAlta Power	52.6%	-0.23	-0.15	0.44	0.28
Canadian Hydro Developers	59.2%	0.76	0.53	1.10	0.76
Averages	52.0%	0.38	0.22	0.36	0.20
Levered avg (60:40)			0.42		0.39
Market Return			8.09%		10.06%
ERP			1.46%		1.99%
Riskless rate			4.65%		5.01%
ROE			6.11%		7.00%
plus flotation & transaction cost			6.61%		7.50%

Appendix B: Comparison of Approaches to Cost of Capital

	Board based on Cannon (2000)	**Staff update using Cannon method (Dec 2005)**	**Lazar & Prisman**
Risk Profiles (Rate Base ranges) Equity %	>$1.0 Bill. – 35% $250-$999 Mill.– 40% $100-$249 Mill. – 45% <$100 Mill. – 50%	SAME	>$299 million – max 40% <$300 million – max 50%
Riskless rate	Avg. of Consensus forecasts for 30 year Canadas **– 6%**	Avg. Consensus forecasts for 30 year Canadas – **4.45%**	Avg of 5,10,15 year forward zero coupon Canadas – **5.01%**
Short term debt mix	Could use 5% to 10%	Not specified	Could use ST debt for wkg cap (to a max)
Rate on long term debt	Riskless rate plus transaction costs >$1.0 Bill. – **6.8%** $250-$999 Mill**.– 6.9%** $100-$249 Mill. – **7.0%** <$100 Mill. – **7.25%**	>$1.0 Bill. – **5.15%** $250-$999 Mill.– **5.25%** $100-$249 Mill. – **5.35%** <$100 Mill. – **5.6%**	Riskless rate plus avg spread of A/BBB corp bonds over Canadas – **6.01%**
Preferred shares	No recommendation	No recommendation	No recommendation
Riskless rate	As for debt	As for debt	As for debt
Market ERP	Basket of equities 3.3% (implicit)		S&P 5 year – 7.17% S&P 10-year-10.06%
Dist. ERP based on CAPM	None (implicit beta = 1)		TSX proxy co.s '04, '05 Post-tax beta 0.357
Transaction adjustment	Board decisions 0.5%	Board decisions 0.5%	None
Net ROE	6 + 3.3 + 0.5 =**9.88%**	4.45+.1+3.8= **8.36%**	Range **5.78% to 7.02%**
Update mechanism	Formula based	Formula based	Annual formula-based over 5 years or expert panel

Appendix C: Calculating the "K-factor"

The 2007 and 2008 adjustments would be calculated as follows if staff's current proposal for K is adopted.

Adjustment	Approach to Calculating "K"	
2007: Changes in ROE There would be four values for "K"; one for each of the current structures listed in Table 2 on page 8 of this report.	Step 1: Select Sample	A large sample of distributors would be selected for analysis. Non-filing distributors, distributors with special circumstances (such as an ROE below both the 9.0% allowed in 2006 and the updated ROE for 2007), or distributors with complex custom 2006 rate models would not be included in the sample.
	Step 2: Calculate Individual K-factors	For each distributor, using the 2006 EDR and tax spreadsheets corresponding to the final Board-approved rates, the change in the Base Revenue Requirement (upon which distribution rates excluding rate riders are determined) would be calculated from the Board-approved amount. This calculation would involve altering the allowed ROE from the 9.0% allowed in 2006 to the updated ROE for 2007. The change in Base Revenue Requirement would also include the change in taxes/PILs due to the change in net income. The distributor-specific K-factor would then be calculated as: $K_{i,2007} = \frac{BRR(2007ROE)_i}{BRR(2006EDR)_i} - 1$.
	Step 3: Determine Size-Group K-factors	While $K_{i,2007}$ can be calculated for each distributor in the sample, it cannot be done for all distributors in the province. Also, certain Tier 1 and Tier 2 adjustments that were done for individual distributors may affect K. To reduce these influences, a $K_{s,2007}$ value would be calculated for each existing size category: $K_{s,2007} = \frac{\sum_{i \in s} K_{i,2007}}{N_s}$. This $K_{s,2007}$ would be incorporated into the 2007 price cap adjustment for each distributor in that size category except those explicitly exempted as discussed below.
2008: Changes in Capital Structure There would be four values for "K"; one for each of the current structures listed in Table 2 on page 8 of this report.	Step 1: Sample	The sample of distributors that the 2008 K-factor analysis would be based is the same as that used for the 2007 K-factor analysis.
	Step 2: Calculate Individual K-factors	For each distributor, using the 2006 EDR and PILs spreadsheets as adjusted for the ROE change in 2007 above, the change in the Base Revenue Requirement that would result from changing the deemed capital structure to 60% debt and 40% equity would be calculated. The distributor-specific K-factor would then be calculated as: $K_{i,2008} = \frac{BRR(2008\,Capital)_i}{BRR(2007\,ROE)_i} - 1$. Distributors in the size category which is defined by rate base size between \$250M and \$1B are already at the target capital structure, therefore their K-factor would be set to zero.
	Step 3: Determine Size-Group K-factors	The size category-specific $K_{s,2008}$ would be calculated as: $K_{s,2008} = \frac{\sum_{i \in s} K_{i,2008}}{N_s}$. This $K_{s,2008}$ would be incorporated into the 2008 price cap adjustment for each distributor in that size category except those explicitly exempted as discussed below.