Ontario Energy Board

Draft Staff Report

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

June 19, 2006

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1 INTRODUCTION

Purpose

Staff of the Ontario Energy Board is releasing this report to assist consultations on two key elements of the Board's multi-year electricity rate-setting plan: the review of the cost of capital; and the development of a 2nd generation incentive rate mechanism ("2nd Generation IRM").

Background

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.

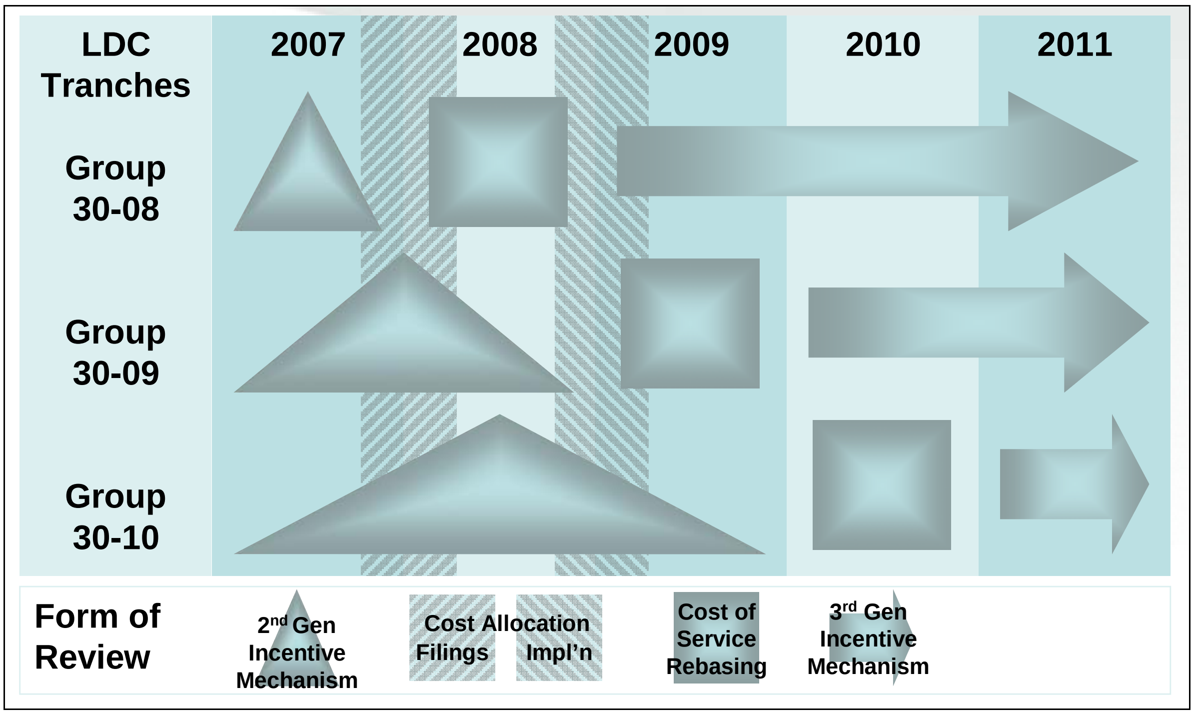
The elements of the Rate Plan and certain key milestones are set out in Table 1, below. The full plan, including the tentative schedule for rate years 2007 through to 2010 is available on the Board's web site.

Table 1: 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 1 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 re-basing reviews into three yearly tranches (i.e., ~30 distributors per year starting in 2008). The rates of

Figure 1: The Board's Multi-Year Rate Setting Plan



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.

The 2nd Generation IRM and cost of capital are the second and third projects to be addressed in the Rate Plan.

Scope of Review

This review will examine the cost of capital using 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 will include a broader examination of the risks faced by distributors.

The term of, and starting base 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 intends to use in relation to this review of the cost of capital and the development of the 2nd Generation IRM.

The Board will implement its cost of capital and 2nd Generation IRM determinations through an amendment to electricity distribution licenses. 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 a new code that will be developed as part of this project: the Incentive Regulation Mechanism Code (the “Code”). Cost of capital will be addressed in two parts: first, during the incentive period between 2007 and 2010 some cost of capital adjustments would be made as described in section 3; and second, as part of the rate re-basing process that begins in 2008, distributors would have their cost of capital set in accordance with the approach described in section 2, below.

Development of the Code will proceed in two phases. This Board staff report launches Phase I of the process to develop the Code – the development of mechanisms and principles. Staff’s proposals are informed by research and analysis by external experts, the Pacific Economics Group and the Schulich School of Business. Board staff’s proposals depart from the experts’ recommendations in a number of ways.

Based on a consideration of Board staff's proposals and comments received from interested parties during Phase I, the proposed Code will be issued for comment by the Board in accordance with the legislative requirements governing the issuance of codes. Notice and comment is Phase II in the process of developing the Code. In light of the written representations received, the Board may propose changes to the proposed Code.

The approved Code will be used to implement rate changes for distributors for a transitional period of up to three years (depending on the distributor as explained in Figure 1 above). This approach will replace the Board's more traditional approach to distribution rate-setting, with the result that the Board will no longer conduct annual cost of service rate hearings for all distributors.

Overview of this Report

This report outlines Board staff's proposals for both the cost of capital and the 2nd Generation IRM. It is intended to provide staff and stakeholders with a common framework for discussion, including the identification of critical issues that interested parties believe require attention or further elaboration. As indicated above, the results of this consultation will be factored into the Board's preparation of the proposed Code on the cost of capital and on the 2nd Generation IRM.

Guiding Objectives

In formulating the proposals, staff has been guided by the Board's statutory 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. **Allow for the opportunity for distributors to earn a reasonable return on shareholder capital and to maintain their financial viability.** This includes the ability to attract appropriate levels of investment.

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 is designed to provide a simple and acceptable 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 Report

The report is organized as follows. The next section describes the conclusions of Board staff on the review of cost of capital and recommends an approach to establishing the cost of capital in the long term as well as the inclusion of cost of capital in the 2nd Generation IRM for the transitional period to 2010. Section 3 provides staff's proposal for the 2nd Generation IRM including an account of each of the major components and the main considerations which support the specific proposals.

2 COST OF CAPITAL

2.1 Theory

The Final Board Report 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 relies 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 in proceeding RP-1999-0034, which established a size-related capital structure of 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 2 and Table 3 provide the allowed ROE, capital structure and debt rates for the 2006 EDR, from the 2006 Handbook.

Table 2: 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 3: 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%

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 employment of the assets will not generate enough income to recover the operating expenses, cost of assets, debt costs, and a fair return to the shareholders.

From the point of view of organizations that provide capital, the question is: what return on investment is required to invest in distributors versus other investment opportunities? The answer depends on the degree of risk the investor is willing to take in relation to earning a profit on their investments. For no risk, an investor would invest in government bonds. Over what period should investors seek a return? This, too, depends upon risk tolerance. Distributors have relatively long-lived assets, so the relevant time period can be quite long. So, to induce investment in distributors 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.

Looking at the same issue from the distributor’s perspective, given the assessment of the risks faced by the business how much revenue would the distributor need to cover all of those risks?

In setting the cost of capital the Board has to consider both viewpoints. What cost of capital will attract enough investment consistent with the risks faced by electricity distributors?

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.

Tax considerations further complicate the picture. Dividends paid to the holders of equity – shareholders – are taxable and reduce the value to the shareholders of their dividends while interest paid to holders of debt is deductible against the taxes of the corporation. As long as a corporation is earning an income it would prefer to issue debt (i.e. borrow) rather than equity (i.e. create shares).

In the case of Ontario, the Board’s previous reviews of cost of capital reveal a general agreement that the industry is among those with lower risks. Beyond that, however, there is a large potential range of risk and the best way of representing that risk in the current circumstances of Ontario’s distributors. 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.

2.2 Approach and Components

As described in Section 1, the Introduction, staff recommends that as a transitional measure the cost of capital should be included as part of the 2nd Generation IRM, which is described in Section 3, below. In 2nd Generation IRM, a separate "K-factor" adjustment to rates is proposed to account for the change in cost of capital of distributors from what is currently reflected in rates. As distributors' rates are re-based their cost of capital would be determined as described below.

Staff's proposals for the three main components to the cost of capital are outlined below:

- Capital structure or debt-to-equity ratio or percentage;
- Return on Equity (ROE); and,
- Debt rate.

In each case, staff proposes maximums for key components: the capital structure, the return on equity and the return on debt. Staff developed the proposal with the assistance of expert consultants, Dr Fred Lazar and Dr Eli Prisman ("Lazar and Prisman"). Their detailed report is available on the Board's web site.

2.2.1 Capital structure

Staff proposes that the appropriate capital structure for distributors is 36% common equity (64% debt). In addition, distributors could include preferred shares as part of their capital structure to a maximum of 4%. In total this would then require 60% debt financing. From numerous sources, including Dr. Cannon's analysis and the work done by Lazar and Prisman, the general view of relative riskiness of electricity and natural gas distributors in other jurisdictions (primarily North America) is that there is no compelling evidence to suggest materially different risk profiles of electricity and natural gas distributors in Ontario. Therefore, staff is guided by the capital structure of the natural gas sector in Ontario with which the Board and financial markets are familiar. Natural gas distributors have a long history of financial stability and their current common equity share is about 36%.

Lazar and Prisman note that there is no common view as to the appropriate capital structure when viewed from a financial markets perspective. As such, staff has relied on the regulation experience gained in the natural gas industry to inform its proposal. The natural gas industry has shown that investment in infrastructure and reasonable returns on investment are not adversely impacted by this proposed capital structure.

This changes the size-related deemed capital structure that was introduced in the first-generation Distribution Rate Handbook and carried forward in the 2006 Electricity Distribution Rate Handbook. In the original framework, utility size was used as a proxy for business risk. The allowed ROE was constant for all electricity distributors, and business risk, proxied by utility size, was accounted for by the different deemed debt/equity ratios and debt rates allowed for different-sized utilities. There is no evidence to suggest that a different size-based capital structure is required to ensure reasonable returns on investment or continued investment in infrastructure. As such, staff is guided by the objectives of a common structure and minimization of the time and resources to administer this framework.

2.2.2 Return on Equity (ROE)

Staff proposes that both the riskless rate for equity and the Equity Risk Premium (ERP) should be determined in the manner recommended by Lazar and Prisman. The overall approach is orthodox. It is based on the well-known Capital Asset Pricing Model (CAPM) which divides ROE into the sum of two terms: the riskless rate, which is taken to be represented by the appropriate Government of Canada securities; and, a risk premium, which reflects the risk of the distributor, measured by a factor known as the "beta" (β). The beta is a measure of the relative riskiness of the firm or industry compared to the overall risk of the whole market over the riskless rate. The equity risk premium is the product of the overall market risk and the firm or industry beta.

In the Board's earlier methodology, the riskless rate was a formula of the *Consensus Forecasts* 3-month and 12-month forecast (forward-looking) for the 10-year Government of Canada bond yield. To this was added the average daily difference between the actual 10-year and 30-year

Government of Canada bond yields in the most recent month, as a means of proxying the forecast 30-year Government of Canada bond yield (commonly referred to as the Long Canada Bond Rate or LCBR) as this is not explicitly forecasted by *Consensus Forecasts*. Following Lazar and Prisman, staff proposes that forward rates are a better indicator of the future cost of riskless capital. The riskless rate would be set by the average of 5, 10 and 15 year forward rates for Government of Canada bonds.

Lazar and Prisman offer two options for setting the riskless rate for the purposes of ROE: fixing the riskless rate for five years or using a panel of experts to select the appropriate sample annually. Staff notes that an annual review would not necessarily result in distributor ROEs being re-based each year. Rather, it results in a new reference for those distributors that are having their rates re-based in any given year. In light of the objective to further predictability and stability, staff do not favor an annual review by a panel of experts.

The risk premium does not specify different elements such as government policy, bad debt, or operating risk. Rather it reflects a market premium that encompasses the overall risk associated with electricity distribution. The risk premium provides an average representation of risk for the industry. This supports the objectives of a common framework that is easy to administer. It also addresses the objective of allowing for the distributor to earn a reasonable return as it reflects more closely the expectations of the financial market.

On the ERP, Lazar and Prisman recommend an annual review and forward two options: a panel of experts would select an appropriate sample of corporate comparators for estimating the beta; or a formulaic approach would be used that adjusts the annual allowable riskless rate for annual differences between the calculated rates (following the expert-based procedure, above) for each successive year. (See Lazar and Prisman for the detailed formula). Staff is undecided about the most appropriate way of estimating ERP. In the appendix to this report, which summarizes various approaches to cost of capital, including staff's proposal, a range for the ERP is presented based on both the methodology proposed by Lazar and Prisman and on an updating by staff of Cannon.

Staff notes that, in common with other Canadian regulatory tribunals, the Board has traditionally included 50 basis points in previous Decisions and guidelines related to the cost of capital as an allowance for flotation and other transaction costs over and above a risk premium calculation.

Staff proposes a continuation of this practice of including a 50 basis points allowance in the ERP.

2.2.3 Debt rate

Long-term Debt

Existing debt will be carried forward at the existing debt rate. Staff proposes that new third-party debt will be set annually at the rate established within the particular debt instrument.

New debt held by affiliates (e.g. municipal shareholder or municipally-owned holding corporation) should have a maximum rate of the riskless rate plus a transaction premium determined by the spread between "A/BBB" corporate bonds and the corresponding Canada. This is consistent with the Lazar and Prisman recommendations.

Short-term Debt

While Lazar and Prisman discuss short-term debt (i.e. less than one year), they make no specific recommendation for the rate of short-term debt. However, they do suggest there should be a limit on the amount of short-term debt. The Board in a separate process is establishing a mechanism to set interest rates for variance and deferral accounts. Staff proposes that short-term debt have a maximum rate set by the Board consistent with the allowed rates for variance and deferral accounts of one year. The Board is currently consulting on the appropriate rates for such accounts.

As for the proportion of debt that should be allowed to be short-term (less than one year), staff proposes that it be limited to working capital. The 2006 EDR Handbook provides for a maximum of 15% of cost of power plus controllable expenses as working capital allowance.

Preferred Shares

Lazar and Prisman offer no specific advice on the treatment of preferred shares. Staff proposes that preferred shares be limited to 4% of rate base. This along with the 36% common equity provides for up to a 40% equity ratio. Total equity including preferred shares will not be allowed to exceed 40% for rate-making purposes.

2.3 Summary of Cost of Capital Proposal

Table 4: Summary of Staff Proposal – Cost of Capital

	% of Rate Base	Return
Debt		
Long-term Debt	Actual percent of rate base	New third party – market rates New affiliate - riskless rate plus transaction allowance updated annually
Short-term Debt	Match to working capital allowance	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		
Preferred Shares	Actual to maximum 4%	Actual rate subject to Board approval
Common Equity	36% rate base	Riskless rate plus ERP updated annually
Total Equity	40%	Weighted average of preferred shares rate and ROE on common equity
Total	**100%**	**Weighted average of debt and equity rates**

Staff has provided a summary of the quantitative implications of the above proposal in the appendix to this report. It is provided in comparison to the following approaches to the cost of capital: the Board's original methodology based on Dr. Cannon; a staff update of this method to the end of 2005; and the approach of Lazar and Prisman. The appendix illustrates how results for the cost of capital may vary depending on the methodology and specific inputs used.

2.4 Integrating Cost of Capital and Incentive Regulation

Staff proposes that during 2nd Generation IRM, distribution rates be adjusted by an incentive formula that will include as one adjustment factor recognition of changes to the existing capital structure, ROE and debt rates. Those distributors whose rates will be re-based will have the proposed cost of capital method applied to their revenue requirements. Until rates are re-based, the adjustment factor will be applied to adjust their revenue requirements. This is explained further in section 3.3.1 (Annual Proxy Adjustment for Cost of Capital – K factor), below.

3 INCENTIVE REGULATION

3.1 Theory

Staff was informed by the advice of Dr. Mark Newton Lowry, of the Pacific Economics Group ("PEG") to formulate 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 PEG Report is available on the Board's web site.

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

3.2 Summary of the Formula

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):

$$\%\Delta P = K + \%\Delta GDPPI - X$$

Where:

- Δ P is the annual percentage change in price;
- K is the adjustment for cost of capital;
- Δ GDP-PI is the annual percentage change in the GDP-PI; and
- X is the 1% required efficiency offset.

The price cap index would only apply to base rates (i.e., applied uniformly across all customer classes and to both the monthly service charge and volumetric rates). Payments in lieu of taxes (PILs) would be a separate calculation after the income is derived from the adjustment. Further, the appropriate rate adders would be layered in after the new base rates have been calculated. This is consistent with the 1st Generation PBR 2002 rate adjustment (2002 RAM).

3.3 Approach and Components

For convenience, the various components of staff's proposed 2nd Generation IRM are summarized in Table 5, below. Each component is discussed in turn in the remainder of this Section.

Table 5: Summary of Staff Proposal – 2nd Generation IRM

Mechanism Component	Staff Proposal
Adjustment for cost of capital (K-factor)	Percentage based on change in ROE and cost of capital
Base	2006 EDR
Form	Price Cap
Term	*Up to* 3 years (per Rate Plan)
Price Escalator	GDP-PI
Productivity Requirement (X-factor)	1%
Contingencies (off ramps and Z-factors)	None
Earnings Sharing	None
Service Quality Requirements	To be enforceable as a condition of licence

3.3.1 Annual Proxy Adjustment for Cost of Capital – K factor

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

First, the "K-factor" that staff proposes for 2007 would numerically approximate the adjustment for changes in ROE and debt rates. It would not adjust for any changes to the capital structure.

Second, for distributors that are still subject to the 2nd Generation IRM (i.e., that do not have their rates re-based 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 3, 2006 Rates Capital Structure and Debt Rates, on page 6 of this report) to the proposed common capital structure.

These adjustments are designed with a view to making distributors indifferent to the timing of their rate re-basing (and implementation of full cost of capital adjustments).

3.3.2 Term (up to 3 years) and Starting Base (2006 EDR)

As indicated in the Board's April 27, 2006 letter announcing this project, the term of (up to 3 years) and starting base (2006 EDR) for the 2nd Generation IRM have already been determined in the Board's multi-year rate setting plan for electricity distributors. There is no expectation that any distributors' rates will be re-based 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 re-based in 2008 will have this mechanism in place for 1 year. Others whose rates are re-based in 2009 will have this mechanism in place for 2 years, and the remaining distributors will have their rates re-based in 2010 which results in this mechanism being effective for three years.

3.3.3 Form: Price Cap

Staff proposes the Board retain a price cap form of adjustment mechanism for electricity distributors.

With regard to alternative mechanisms, at this time, staff believes that the data and modeling requirements necessary to establish a yardstick competition framework for the Ontario electricity distribution sector are prohibitive. 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 contributing to price uncertainty. Staff is not convinced that the benefits to distributors outweigh the risks to consumers.

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

3.3.4 Price escalator: GDP-PI

A survey of incentive regulation formulas approved in other jurisdictions shows that the Gross Domestic Product Price Index (GDP-PI) is the prevalent inflation proxy used by North American regulators for gas, electric, and telecom utilities. Dr. Lowry provides 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 inflation measures used in those jurisdictions. Although a macroeconomic measure, the GDP-PI 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. These benefits of simplicity and transparency outweigh the costs of developing and administering an industry-specific measure for the 2nd Generation IRM. With regard to use of CPI rather than GDP-PI, staff agrees with Dr. Lowry that GDP-PI is preferable to the CPI because it tracks a more relevant set of goods and services. CPI tracks the prices of consumer goods and services, whereas GDP-PI is a broader measure of inflation that covers all sectors of the economy. Therefore staff proposes that GDP-PI 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 of the view that the GDP-PI 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.

3.3.5 X-factor: 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.

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) and 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).

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 simple 1% X-factor for the duration of the 2nd Generation IRM. Referring to the X-factor precedents summarized on page 55 of the PEG Report, staff notes the 1.01% sample average for cases which employ macroeconomic inflation measures, and proposes 1% as a reasonable reflection of relevant input price and productivity trends. Staff believes that the proposed GDP-PI and 1% X-factor together should track industry unit cost over the short-term of the 2nd Generation IRM.

3.3.6 Contingencies and mid-term issues

Z-Factors

Staff proposes that the 2nd Generation IRM not provide for any Z-factors. Staff acknowledges that the Board concluded in the recent Natural Gas Forum, 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 up to 3 years for others), staff does not see a need for pre-defined Z-factors.

Off Ramps

With regard to pre-defined off ramps, for the same reasons as provided above (i.e., the varied and relatively short period of application of the 2nd Generation IRM), staff does not see a need to include any provision to allow distributors to exit the 2nd Generation IRM.

3.3.7 Earnings sharing

Staff does not propose an earnings sharing mechanism (ESM) be part of the 2nd Generation IRM. An ESM may reduce the distributor's efficiency incentives and introduce a potentially costly additional regulatory process.

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 Electricity Distribution Rate Handbook (EDRH). For convenience, the list of the SQIs that distributors are required to measure and report on are provided in Table 6, below.

Table 6: Service Quality Indicators in the EDRH

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.

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.

Upon resumption of this review, staff proposes that the frequency of service quality reporting be increased to quarterly reporting of monthly data. While the Board has established regular reporting of service quality, annual reporting may be too infrequent. It may be up to 12 months before a service degradation occurring in January or February is reported and comes to the Board's attention. Further, staff proposes that the Board publish the service quality reports filed by distributors on its web site.

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

3.3.9 Conservation and Demand Management (CDM)

Electricity distributors are an important part of work by the Government of Ontario to bring about a culture of conservation.

The Ontario Power Authority has certain legislated authority in respect of CDM in Ontario, and many of its CDM activities are conducted through its Conservation Bureau. Among other things, the Ontario Power Authority is specifically authorized to enter into contracts with distributors for the provision of CDM services.

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.

While this may increase the complexity of the framework, it is consistent with commitments made in the 2006 EDR review processes.

3.3.10 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.

3.4 Looking Forward to 3rd Generation IRM

Staff is working on details for the 2008, 2009, and 2010 re-basing 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 be a full traditional rate case;
- 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 is an issue of mounting interest to the Board as it progresses with incentive regulation.

APPENDIX: COMPARISON OF APPROACHES TO COST OF CAPITAL

	Board based on Cannon (2000)	**Staff update using Cannon method (Dec 2005)**	**Lazar & Prisman**	**Staff Proposal**
CAPITAL STRUCTURE				
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 50% <$300 million – max 40%	All – MAX 36% common
DEBT				
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%**	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)	Could use ST debt for wkg cap (15%)
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%**	Riskless rate plus avg spread of A/BBB corp bonds over Canadas – **6.01%**
Preferred shares	No recommendation	No recommendation	No recommendation	Max 4% up to 40% of all stock
RETURN ON EQUITY				
Riskless rate	As for debt	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-10.6%	S&P 10-year – 10.6%
Dist. ERP based on CAPM	None (implicit beta = 1)		TSX proxy co.s ‘04, ‘05 Post tax beta 0.357	Range TSX proxy co.s ‘04, ’05 post tax beta 0.357 to beta 0.6 (implicit ROE update)
Transaction adjustment	Board decisions 0.5%	Board decisions 0.5%	None	0.5%
Net ROE	6 + 3.3 + 0.5 =**9.88%**	4.45+.1+3.8= **8.36%**	Range 5.01+(7.17-5.01)*.357 = **5.78% to** + (10.6-5.01)*.357 = **7.02%**	Max Range: from 7.02 + 0.5%= **7.52% to 8.36%**
Update mechanism	Formula based	Formula based	Annual formula-based over 5 years or expert panel	Annual formula based – continuous