CHAPTER 3
ESTABLISHING BASE RATES

3.1 INTRODUCTION

This Chapter discusses how base rates will be established. The base rates are the unbundled rates adjusted for a market-based rate of return and prudent and material transition costs that have arisen by the time of the filing of the distributors' evidence for the first year of the PBR plan. Appendix A to the handbook provides an extensive discussion of the specific calculation process that has been adopted for unbundling the rates[1]. A distribution utility may either use this adopted procedure or its own procedure although justification for the reasonableness of that procedure will be required.

This Chapter is organized in three sections: unbundling of current rates into distribution and commodity components to construct class-specific distribution revenue requirements, adjustments to these initial revenue requirements, and distribution rate design.

3.2 UNBUNDLING CURRENT RATES

One of the challenges facing Ontario electric distribution companies is to restructure their organizations for the impending choice of electric supplier that customers will be able to exercise. This challenge is evident in the current revenue model of distributors, which must be altered for the possibility that not all customers will be on default (or standard) supply service from the distributor. Those customers who choose an alternative supplier must still pay for the distribution of the commodity from the point of wholesale delivery to the point of customer delivery as well as for the other services provided associated with distribution.[2] This means that the existing rates must be unbundled.

Ideally, cost allocation studies coupled with cost of service studies would be available to guide the unbundling process. Unfortunately, the studies that are available appear to be quite old. Hence, a simplified procedure is described here (with greater detail and examples in Appendix A) for unbundling current rates. Should the distribution utility have better information on which to unbundle their rates, they are encouraged to use such information.

[1] Appendix A will become a component of Part B of the rate handbook.
[2] Currently, the Board is considering the form of settlements and billing to be adopted within the Province. Billing for distribution services, as well as for IMO, transmission, and commodity services, must be conducted according to the settlement code adopted by the Board.

The beginning premise of the simplified procedure is that existing rates appropriately recover costs from each of the rate classes. If this is so, then by allocating the cost of power to each of the rate classes an initial revenue requirement (preserving rate class revenue neutrality) can be constructed. Consider equation 3-1:

Class Distribution Revenue Requirement = Class Revenue – Allocated Power Cost [3 – 1]

In other words, the key to determining the class revenue requirement is to allocate the power bill against the revenue collected from each of the rate classes. Embedded in the power bill is the cost of the commodity as well as the cost of transmission. When the market opens, the distribution utility will be billed for the commodity and transmission separately, but the retail settlement system will allow the distributor to pass these expenses on to the customer directly. Hence, separating the historical power expenses from the historical revenues provides the distribution-related revenues.

Appendix A presents a methodology to allocate the power bill to rate classes. The process uses readily available data to do so. The process is as follows:

1. The class revenue at existing rates and power bill are determined using the most recent audited financials and actual end-use kW and kWh amounts.

2. To calculate the class level cost of power (COP), the end-use kW and kWh amounts at the wholesale level must first be determined. For the large use rate class, a loss rate of 1% should be applied to the aggregated load profile constructed by adding the interval metered load profiles of the individual customers. For other customers, the five-year loss rate (adjusted for the assumed 1% loss rate for large use customers[3]) should be used to construct wholesale level billing demand and energy figures. These wholesale quantities are applied against the wholesale tariff in place at the time of the power bill to derive the class-specific COP.

3. The class's initial distribution revenue requirement is obtained by subtracting the customer class's COP determined in (2) from the class revenue at current rates determined in (1). This ensures class revenue neutrality at existing rates in the unbundling of the distribution and COP revenue streams.

[3] The 1% distribution system losses associated with the large use customer class is an assumed loss rate. While the actual loss rate may be greater or less than this level, the assumption washes out when the class is charged for losses in the retail settlement system. For example, if the actual large use loss rate is 2% instead of the assumed 1%, then the distribution charge would be too high, but the loss charge would be too low.

3.3 ADJUSTMENTS TO INITIAL REVENUE REQUIREMENTS

The calculations above yield an initial estimate of the revenue requirement to cover distribution expenses. However, several adjustments need to be made to adjust for a market-based rate of return (if desired) and for possible prudent and material transition costs.

3.3.1 Market-Based Rate of Return

With respect to the market-based rate of return, utilities may choose to base their rates at any rate of return level up to the market-based level. It is likely that rates will need to be adjusted to initially capture the target rate of return. Due to the effects of contributed capital on the determination of equity, we first discuss the treatment of contributed capital, then the calculation of the adjustment for the market based rate of return, and finally the issue of rate impacts associated with these charges.

3.3.2 Contributed Capital

Contributed capital collected under Ontario Hydro's regulatory regime and currently included in rate base will remain in rate base. The distributors will continue to earn a return on the contributed capital portion of the existing rate base until these assets are fully depreciated. However, the rate of return that will be applied to this component of the rate base will be the 1994-1999[4] average equity rate of return for the utility, subject to a zero per cent floor and a 9.75% maximum. For distributors that amalgamate, the attributed equity rate of return on the contributed capital component will be the 1994-1999 weighted historical average figure return on equity (weighted by the equity components, including contributed capital) of the constituent utilities.

The distributors will continue to charge the depreciation expenses associated with the contributed capital portion of their existing rate base to operating expenses until the assets are fully depreciated. To determine the net value of these assets, they should be netted based on the average class depreciation rate of those classes to which the contributed capital applies.

This approach gives consideration to the regulatory framework that the distributors were subject to prior to the Board's assumption of this regulatory oversight. The approach leaves both the distributor and its customers no worse off than they were under the previous regulatory regime.

Going forward, under the Board's regulation, contributed capital collected by the electric distributors will not be included in rate base. As a result, the distributors will not be earning a

[4] The Board will determine a specific date within the year 1999 through which historic contributed capital will receive this rate treatment. Subsequent to that date, contributed capital will no longer be included in rate base.

return on the contributed capital collected in the future, nor will they be allowed to charge the associated depreciation expense to operating expenses.

3.3.3 Calculation of the Market-Based Rate of Return Amount

The market-based rate of return (MBRR) adjustment, if elected by the utility, should be based upon a common equity ratio (CER) of CER%, a debt-to-capital ratio of (1-CER)%, a target return on equity of 9.75%, and a debt rate of DR.

The formula for calculating the market-based rate of return is given in equation 3-2.

$$\text{MBRR} = (\text{Rate Base} - \text{Contributed Capital}) \times \left(\frac{\text{CER} \times .(0975 - \text{Actual ROE})}{(1 - \text{effective tax rate})} + (1 - \text{CER}) \times \text{Debt Rate}\right) + \text{Contributed Capital} \times \text{Contributed Capital Return Rate} \quad \text{3-2}$$

Note that the Contributed Capital component of equation 3-2 is that amount that is "grandfathered" as discussed in section 3.3.2. The CER%, (1-CER)%, and debt rate (DR) values to use in the above formula depend on the size of each utility's rate base, as set out in Table 3-1.

Table 3-1
Common Equity Ratios and Debt Rates

Size of Utility Rate Base	CER%	(1-CER)%	DR
Greater than $1.0 billion	35%	65%	0.0680
Between $250 million and $1 billion	40%	60%	0.0690
Between $100 million and $250 million	45%	55%	0.0700
Under $100 million	50%	50%	0.0725

For example, a utility with a rate base of $60 million - of which $10 million is contributed capital that has earned an average equity rate of return of 5.00% over the 1994-1999 period, earned 0% ROE for 1999, and faces a 43.5% marginal payment in lieu of taxes (PILS) tax rate will have a MBRR adjustment as follows:

MBRR = ($60 MM - $10 MM) x (((.5 x (.0975-0))/(1- .435)) + .5 x .0725) + ($10 MM x .0500)

= ($50 MM x .122533) + ($10 x .0500)

= $6.126655 MM + $0.500 MM

= $6.626655MM or $6,626,655

The above ROE and DR values are based on a forecast that long-term Canada bond yields will average between 5.95% and 6.00% during 2000. The actual values will be provided at the time of publication of the final handbook.

3.3.4 Transition and Extraordinary Event Cost Adjustments

Utilities may experience significant recurring, and one-time costs associated with the transition to the new market. To the extent that these transition costs have been incurred by the time of the submission of the utility's evidence, the utility may include qualifying transition expenses in initial rates. Further, if extraordinary events have caused the utility to incur costs that are currently not included in base rates, the utility may include qualifying extraordinary costs in initial rates. All such costs must be specifically identified and justified.

For transition or extraordinary event costs to be qualifying expenses for this adjustment, they must meet the four criteria test (causality, materiality, inability of management to control and prudence) described in Section 4.4.1. All such costs must be specifically identified and justified. The utility must submit evidence supporting the qualification of their claim in their filing. In addition, should these transition or extraordinary costs be capitalized, an adjustment to initial revenue requirements should be calculated. If these amounts are to be expensed, then they should be included in the balancing account discussed in Chapter 4.

3.3.5 Potential Rate Impacts

The rate impacts associated with the market-based rate of return, transition costs, and extraordinary costs may be substantial. Should the utility find that these rate impacts appear excessive,[5] the utility may wish to use a deferral account to spread costs, with accrued interest, over future years.

3.3.6 Calculating the Final Rate Class Revenue Requirement

These adjustments to revenue requirements should be summed and spread to the rate classes in proportion to the initial class revenue requirements.

3.4 RATE DESIGN

Utilities should translate these final class revenue requirements into two-part rates: a monthly service charge plus a rate that reflects differences in customers' usage/demand of the system and,

[5] The Board encourages utilities to consider these options when the resulting increase in rates (based upon service revenues) is, as an example, in excess of 10%.

as such, addresses equity between customers within a customer class. In the case of demand-metered customers, the demand charge for distribution should be based on the incremental distribution cost. For energy-metered customers, the energy distribution charge should be based on the incremental distribution cost. The residual is then divided by the number of customers in the class and by 12 to derive a monthly service charge.

Losses will be initially included in the commodity charge and, subsequent to market opening, separately. The loss rate will be fixed for non-large use customers at the 5-year average loss rate adjusted for an assumed loss rate of 1% on large use consumption. For large use power customers, the loss rate will be assumed to be 1%. The wholesale quantities developed as described in Section 3.2 include the proper allowance for distribution system losses. Hence, to derive the commodity charge for energy, transmission and distribution system losses prior to market opening, one needs only to divide the COP allocated to the rate class by rate class retail quantities (as determined in step 2 in Section 3.2).

Subsequent to market opening, the cost of power and transmission will be calculated in accordance with the retail settlement code. The loss rates, noted above, will be used to calculate an allowance for losses based upon the monthly pool prices. This puts the distribution utility at risk for deviations in the quantities of losses, but not for their price.