CHAPTER 3
ESTABLISHING INITIAL UNBUNDLED RATES

3.1 INTRODUCTION

This chapter discusses how initial rates (rates introduced in 2000-2001) will be established for the first generation PBR plan. The initial rates are the unbundled rates adjusted for market-based rate of return ("MBRR"). It is a utility's choice whether to apply for rates that incorporate the total allowable return, but any such decision should be made with regard to rate impact. Consistent with the Board's finding in the Decision on the Minister's Directive of June 7, 2000 (RP-2000-0069), any incremental revenue necessary to move the utility to its desired level of return within the Board's specified market return level, exclusive of payments-in-lieu of taxes "PILs", will have to be phased-in evenly over three rate adjustment periods. Implementation details on the specific calculation process that has been adopted to set initial rates are provided in Chapter 4. Appendix C provides documentation on the Rate Unbundling and Design Model ("RUD") spreadsheet provided to the electricity distribution utilities to assist them in their rate derivation. An electricity distribution utility may choose either to use the Model provided in Chapter 4 and Appendix C, or its own load profile and cost allocation data. If a utility is using its own data, justification for the reasonableness of its procedure must be included in its evidence for initial rates.

This chapter is organized in three sections: unbundling of current rates into distribution and commodity components to construct class-specific distribution revenue requirements; distribution rate design; and adjustments to these initial revenue requirements to account for a MBRR.

3.1.1 Approach to Setting Initial Rates

The starting point for determining initial unbundled rates is based on the existing rates. The following elements describe the approach taken to determine initial rates:

- Unbundling of current customer class revenue requirements into distribution and COP revenue requirements.

- Development of initial distribution and COP rates.
- Assessment of the impact of such rates on total bill.
- Adjustment of revenue requirements for the selected return on equity ("ROE") level (i.e. the MBRR).
- Phase-in of incremental revenue to move towards MBRR (exclusive of PILs).

3.2 UNBUNDLING CURRENT RATES

One of the challenges facing Ontario electricity distribution utilities is to restructure their organizations to respond to the restructuring of the electricity market under which customers will be able to exercise choice of electricity supplier.

The current revenue model of electricity distribution utilities must be altered to accommodate the likelihood that not all customers will stay on SSS from the electricity distribution utilities. 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 by the electricity distribution utility. This means that the existing distribution rates must be unbundled.

Ideally, cost allocation studies would be available to guide the unbundling process. Unfortunately, the studies that are available are old. Hence, a simplified procedure is described here for unbundling existing rates. Should a utility have better information on which to unbundle rates, they are encouraged to use such information, as long as justification can be provided in support of initial rates.

The beginning premise of the unbundling procedure is that existing rates appropriately recover costs from each of the rate classes. By allocating the COP to each of the rate classes an initial revenue requirement can be constructed that preserves class revenue neutrality. Consider equation 3-1:

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

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 electricity market opens, the electricity distribution utility will be billed by the IMO for the commodity and transmission separately, according to the RSC. Chapter 11 will provide further guidance on the RSC and DSC.

Chapter 4, along with the RUD Model, presents a methodology to allocate the power bill to rate classes. The process uses readily available data and a load profile model. The process is as follows:

1. The class revenue at existing rates and power bill are determined using 1999 year-end (12-month data) actual end-use kW and kWh amounts.

2. To calculate the class level COP, the end-use kW and kWh amounts at the wholesale level must first be determined. For the large use rate class, a default loss rate of 1 per cent should be applied in the absence of utility specific data 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[1] (adjusted for the assumed 1 per cent, or actual, loss rate for large use customers) should be used to construct wholesale level billing demand and energy figures. These wholesale quantities are applied against the applicable wholesale rates to derive the class-specific COP.

3. The class' initial distribution revenue requirement is obtained by subtracting the customer class' 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.

3.3 RATE DESIGN

The initial class revenue requirements determined above are used to set a two-part distribution rate consisting of a monthly service charge and a volumetric kW or kWh rate. The monthly service charge is designed to recover the distribution fixed costs. The volumetric charge is intended to reflect, to some degree, differences in customers' use of the distribution system and, as such, addresses equity between customers within a customer class. In the case of demand-metered customers, the volumetric charge will be a per kW charge. For energy-metered customers, the volumetric charge will be a per kWh charge. The basis of the volumetric charge is the incremental distribution cost ("IDC").

The IDC used in the volumetric rate derivation presented in Chapter 4, and used in the

[1] This loss rate calculation is specific to the rate unbundling process. The actual losses will be settled according to the RSC. Any further details and requirements related to losses will be included in Chapter 11.

RUD Model, is \$0.0062/kWh. Conceptually it represents the cost of providing the next kWh and includes incremental operating and maintenance expenses, incremental capital investment, and incremental financing charges. The IDC value was derived in a 1980's joint Ontario Hydro-Municipal Electric Utility ("MEU") study and is the value that was included in the MEU's rate setting under Ontario Hydro's regulatory regime. As such, \$0.0062/kWh is the IDC value included in the electricity distribution utilities' existing rates.

Where a utility has its own IDC value, it should use it in filing for initial rates and include justification for that value.

3.3.1 Impact on Total Bill Resulting from Change in Rate Design

In moving to a two-part distribution rate structure, some small volume customers may see a significant rate impact. The impact increases with the size of the monthly service charge. The service charge should be set so that rate impact resulting from the change in rate structure does not exceed 10 per cent of total bill (relative to annual bill using current bundled rates), for the small volume customers group in a rate class (see Chapter 4). In mitigating the impact on total bill, the monthly service charge should be lowered and the volumetric charge raised to a point where the impact on the small volume customers group within a rate class is less than 10 per cent. Class revenue requirement neutrality must be maintained in meeting the rate impact mitigation requirement.

The RUD Model, described in Appendix C, will assist electricity distribution utilities in ensuring that the impact on the small volume customers group does not exceed 10 per cent of total bill, on an annualized basis. If an electricity distribution utility cannot attain the 10 per cent limit while maintaining total class revenue neutrality, it must highlight this in its evidence in support of initial rates.

3.4 ADJUSTMENTS TO INITIAL REVENUE REQUIREMENTS

Procedures described above yield an initial estimate of the revenue requirement to cover distribution expenses. However, an adjustment needs to be made to allow for returns up to the MBRR, if the electricity distribution utility chooses to do so.

3.4.1 Market-Based Rate of Return

With respect to the MBRR, electricity distribution utilities may choose to base their rates at any rate of return level up to the Board approved market-based level. In this case, rates will need to be adjusted to initially recover the increased revenue requirement necessary to meet the target rate of return. The recovery of increased revenue requirement will be phased-in evenly over the three rate adjustments during the first generation PBR term. Due to the effect of the size of rate base on the necessary revenue requirement, the determination of rate base, as well as the Board specified market return level (i.e., the allowable MBRR) are discussed first followed by the description of the calculation of the adjustment to initial revenue requirement for the MBRR. Finally, the phasing-in mechanism as well as transition costs are discussed.

3.4.1.1 Definition of Rate Base

The electricity distribution utility rate base is the year-end net fixed assets (distribution "wires only") plus a working capital allowance.

Net fixed assets is the total distribution "wires only" fixed assets minus the total accumulated amortization. Account details are presented in Appendix D and amortization schedules are presented in Appendix E.

The working capital allowance to be included in the rate base for first generation PBR plan is 15 per cent of the sum of the 1999 COP and controllable expenses. This accounts for approximately 2-months of COP and 1½ months of controllable expenses (sum of Operations and Maintenance, Billing and Collection, and Administration), which results in approximately similar levels allowed by the previous regulator. The working capital allowance component for the COP may need to be adjusted at market opening to ensure consistency with the market rules, in which case the utility may file with the Board for such a change as a transition cost after market opening.

3.4.1.2 Contributed Capital

Contributed capital collected by the electricity distribution utilities on or after January 1, 2000 will not be included in rate base. As a result, the electricity distribution utilities, like the gas utilities regulated by the Board, will not be earning a return on the contributed capital collected in the future, and will not be charging the associated depreciation expense to operating expenses.

Historical contributed capital included in rate base under the previous regulator's regulatory regime is considered a unique case and will remain in rate base. Electricity distribution utilities will continue to earn a return on the historical contributed capital included in existing rate base prior to January 1, 2000 until these assets are fully depreciated. The rate of return that will be applied to this component of the rate base will be the same level as that which the electricity distribution utility is earning on the remaining assets in its rate base. The electricity distribution utilities will also continue to charge the depreciation expenses associated with the historical contributed capital portion of their existing rate base to operating expenses until the assets are fully depreciated.

In accordance with the Board's Decision RP-2000-0069, the amounts of contributed capital which may be collected after September 29, 2000, shall be determined in accordance with the provisions of the *Distribution System Code*.

3.4.1.3 Board Specified Rate of Return on Common Equity (ROE) level for 2000

The methodology for determining the Board's annual rate of return on common equity (ROE) for electricity distribution utilities is based on the methodology used by the Board in regulating natural gas utilities. The actual values of both the debt rate ("DR") and the return on common equity have been calculated by the Board using data from December 1999. The ROE ceiling for 2000 has been set at 9.88 per cent based on a forecast of long-term Canada bond yield.

3.4.1.4 Calculation of Additional Revenue Requirement to Include in Rates the Allowed MBRR

Most of the electricity distribution utilities have not historically earned market-based rates of return. Upon corporatisation, with the municipality installed as shareholder, a municipally-owned electricity distribution utility may wish to propose rates that target returns up to the allowable ROE ceiling.

If it is the electricity distribution utility's choice to increase its level of ROE, its initial rates will need to be adjusted for the increased revenue required to bring the electricity distribution utility to its target ROE. A method of determining the additional revenue required is provided below. Once the additional revenue associated with ROE has been determined, this additional revenue along with that resulting from the cost of debt as specified in the MARR formula [3-2], shall be phased-in evenly over the three-year term of the first generation PBR. This is discussed further in section 3.4.1.5.

For the purposes of calculating the additional revenue required and the resulting adjustment to rates to achieve market-based returns, the Board requires that the electricity distribution utilities use a deemed capital structure and debt rate as specified in Table 3-1.

The revenue requirement adjustment for a return up to the MBRR, if elected by the electricity distribution utility, should be based upon a deemed common equity ratio ("CER") of CER per cent, a debt-to-capital ratio of (1-CER) per cent, a target return on equity ("TROE") of up to 9.88 per cent, and a DR (see Table 3-1). The DR is based on the forecast long-term Canada bond rate.

The formula for calculating the pre-market opening (i.e., exclusive of PILs) Market Adjusted Revenue Requirement ("MARR") for 2000-2001 rates is given in equation 3-2. The 1999 Rate Base is the distribution "wires only" 1999 year-end rate base calculated in accordance with Table A.3 in Appendix D.

$$\text{MARR} = (\text{1999 Rate Base}) \times \big((\text{CER} \times \text{Target ROE}) + ((1 - \text{CER}) \times \text{DR})\big) \qquad [3\text{-}2]$$

This equation calculates the total revenue requirement associated with the return on equity and debt expense. Pre-market opening rates will not include a revenue requirement for PILS. Post-market opening rates will include PILS. Upon market opening, rates will be adjusted to reflect PILs. PILs will apply to the portion of MARR related to ROE and will be prorated for the amount of ROE which has been phased-in. Further information on this calculation, as well as the appropriate tax rate, will be available once a market opening date has been established.

The deemed CER per cent, (1-CER) per cent, and 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
Deemed Common Equity and Debt Ratios and Debt Cost Rates

Size of Utility Rate Base	CER%	(1-CER)%	DR
Greater than $1.0 billion	35%	65%	6.80%
Between $250 million and $1 billion	40%	60%	6.90%

Between $100 million and $250 million	45%	55%	7.00%
Under $100 million	50%	50%	7.25%

For example, a utility with a rate base of $60 million will have a MARR adjustment as follows:

MARR = ($60 MM) x ((.5 x .0988) + .5 x .0725)

= ($ 60 MM x .08565)

= $5.139 MM or $5,139,000

In order to determine the additional revenue that a utility must collect in order to avail itself of the maximum allowable adjustment for market-based rates, the return on capital that the utility earned during 1999 is subtracted from the revenue requirement derived in [3-2] as follows:

Additional Revenue to Move to Targeted Return = Year 2000-2001 MARR - (1999 Rate Base x ROE1999) [3-3]

The 1999 ROE is the rate of return on all business activities in 1999 and is defined as “The rate of return using the instruction on page 5 of 5 of subject 8020 in the Accounting for Municipal Electric Utilities in Ontario manual”. In its decision, the Board made the simplifying implicit assumption that "the integrated utility earned the same rate of return on all its business activities." Any utility with a negative ROE in 1999 will be subject to the floor value of 0 per cent.

3.4.1.5 Phase-in of Revenue Requirement Associated With Market Returns

As a result of the Board’s Decision on RP-2000-0069, the *Additional Revenue to Move to Targeted Return* must be phased-in evenly over the next three rate adjustment periods (i.e., 2000-2001, 2002, 2003). Therefore, the adjustment to the year 2000-2001 revenue requirement will be one-third of the total *Additional Revenue to Move to Targeted Return* calculated in equation [3-3]. Once determined, the adjustments to year 2000-2001 revenue requirements should be summed and allocated to the rate classes in proportion to the initial class revenue requirements.

In the unusual situation where a utility may face special circumstances where the phasing-in process may cause financial distress, the utility can apply for a skewed phase-in process. The skewed phase-in process may allow the utility to recover a greater proportion of *Additional Revenue to Move to Targeted Return* in its 2000-2001 rates. However, utilities that claim special circumstances must recognize that there will likely be additional processes needed to deal with its application.

3.4.1.6 Customer Notification

While the decision to move to MBRR is that of a utility's management, directors and shareholder, the Board requires the utility to inform and explain the rate change to its customers as well as the reasons thereof. This could be accomplished by published notice (see Appendix B) or Board-approved bill insert.

3.4.2 Deferral Accounts For Transition Costs and Extraordinary Events

Electricity distribution utilities will not be required to make specific applications for deferral accounts established or for the purpose of transition costs. The Board's Decision on RP-1999-0034 should be viewed as the only regulatory instrument required to establish these accounts. Accounts 1570, "Qualifying Transition Costs" and 1572, "Extraordinary Event Costs", have been established in the Accounting Procedures Handbook for these purposes (See Chapter 5). Note that as a result of the Board's Decision on RP-2000-0069, there will be no deferral of return not reflected in rates and, as such, there will be no deferral account for this purpose.

3.5 OTHER RATE MATTERS

3.5.1 Minimum Bill

Electricity distribution utilities that currently have a minimum bill provision may continue to use it for first generation PBR, if it is necessary to retain such a provision in order to mitigate the rate impact on customers. However, any such request must reflect the separation of distribution rates from COP. The minimum bill provision will be reviewed for second generation PBR.

3.5.2 Load Control Discount

The load control discount currently offered by electricity distribution utilities is based on the utility's wholesale bill savings resulting from load control. The savings are a result of shifting demand off the utility's peak thus reducing the utility's wholesale demand cost. The distributor's load control is generally limited to water heater load control. Part of the utility's savings resulting from water heater load control is usually provided to a customer participating in the load control program, typically through a discount on the water heater rental charge.

Since the electricity distribution utility's existing load control programs are related to the COP rather than demand on the distribution systems upon market opening load control discount will no longer apply. However, upon market opening a utility could sell load control service to a customer that has a load control contract with a retailer. In justifying the load control rates, the utility would have to demonstrate full distribution cost recovery on the program. The load control rate would be considered a miscellaneous (specific service) charge.

3.5.3 Miscellaneous/Specific Service Charges

Miscellaneous, or, specific service charges are charges for services that are not included in an electricity distribution utilities' standard of service and, therefore, are not included in standard service rates, but rather, are charged for through a miscellaneous charge. While all utilities must at minimum include all services related to a electricity distribution utility's core function in maintaining and operating its distribution system, there are some extra services an electricity distribution utility may or may not choose to include in its standard service. Some of these service charges are arrears certificates, account setup, remote metering, and non-payment of account charges.

The level of these charges will be held at the current approved levels. If a change in the level of a miscellaneous charge is sought, the utility will need to provide cost justification for this adjustment.

The RUD Model includes a page for reporting miscellaneous charges. The 1999 and 2000 miscellaneous charge levels should be itemized on this page.

3.5.4 Rural or Remote Rate Protection

Rural or remote rate protection will be administered according to the regulation made under the Act. A regulation outlining the methodology for providing this protection under unbundled rates has not yet been made.