REPORT OF THE
ONTARIO ENERGY BOARD
PERFORMANCE BASED REGULATION
CAP MECHANISM TASK FORCE

MAY 18, 1999

Prologue

The Ontario Energy Board (OEB) is proposing performance-based regulation (PBR) for the electricity distributors in Ontario. The OEB's approach in developing a PBR framework for electricity distribution is to involve the stakeholders through task force efforts. As such, the OEB set up four PBR task forces consisting of volunteer stakeholders to examine the following: cap mechanisms, yardstick grouping, implementation issues, and distribution rates. The task forces had a total of 83 members representing various electricity distributors, gas utilities, customer groups, and special interest groups.

The Task forces were formed in mid-January and worked on the assigned tasks for approximately 3 months. The task force meetings were co-managed by OEB consultants Michael King and Frank Cronin of PHB Hagler Bailly, who also provided the task forces with technical expertise on PBR and restructuring issues in general.

To address the diversity of scope and the large number of emerging issues, working groups were formed within the task forces. Each working group produced reports which Board staff has collated into the task force reports.

All four task forces ran into concerns that led to the common proposal that the OEB should allow for a regulatory transition period. The regulatory transition period would allow utilities the opportunity to meet restructuring requirements without rigorous regulatory impositions, and allows for the collection of consistent and robust baseline data for PBR. The task forces agreed that a three-year first generation PBR plan should apply for the transition period to avoid gaming opportunities, in anticipation of PBR, during the transition period.

The first generation plan will have sophisticated incentive parameters (i.e. industry specific price indexes and productivity factors) developed from data collected from the electricity distributors and will also have risk mitigation terms (i.e. earnings-sharing). However, inconsistencies in data and utility practices precluded the implementation of yardstick groupings and a complete set of comprehensive performance standards applied to all distributors for the first generation plan.

The OEB would like to express its sincere appreciation for the conscientiousness of the task forces members and the time expended on the task force efforts, as well as its admiration for the collaborative attitude demonstrated by each of the task forces. Board staff and their consultants are confident that the outcomes of the discussions by the task forces will facilitate the production of a draft Board PBR Rate Handbook and result in a fair and practical PBR framework for the electricity distributors in Ontario.

OUTLINE

PARTICIPANTS

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TASK FORCE MANAGEMENT TEAM

Co-Manager	Michael King	Vice-President, PHB Hagler Bailly Consulting, Inc.
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1. INTRODUCTION

The objectives of the Cap Mechanism Task Force was to (1) assess alternative cap mechanisms, (2) review and assess methods and data for establishing price and productivity adjustment factors for the PBR cap scheme adopted, and (3) compile data collection procedures for periodic submissions to the OEB.

As such the task force were to consider the following:

- Criteria to determine which electricity distributors would be suited to cap regulation;
- Form of cap mechanism (price, cap or a hybrid combination);
- Input price adjustment;
- Industry specific purchases; and
- Method/data for productivity factor (includes information on output prices and amounts, as well as input prices and amounts);

2. CAP MECHANISM

2.1 Background

The White Paper on electricity market reform, entitled Direction for Change, strongly endorsed the development and implementation of a performance-based regulatory framework (PBR) for the monopoly elements of the restructured Ontario electricity market. Subsequently, the Electricity Competition Act assigned responsibility for the regulation of these elements to the Ontario Energy Board (OEB) and allowed the OEB to carry out its mandate using PBR.

To explore the PBR options available to it in regard to the electricity distribution industry, the OEB formed four task forces to explore various aspects of PBR systems that might be applied to this industry. This report provides the results of the work of the Cap Mechanism Task Force (CMTF), which examined a central feature of any PBR system, namely the nature of the cap mechanism to be used in setting prices for the regulated entity.

The terms of reference set for the task force were:

- Assess alternative cap mechanisms;
- Review and assess methods and data for establishing price and productivity adjustment factors for the PBR cap schemes;
- Assemble and compile necessary underlying data for estimating adjustment factors, evaluate the implications of cap/factor alternatives for stakeholder impacts; and,
- Recommend data collection procedures for periodic submission to the OEB.

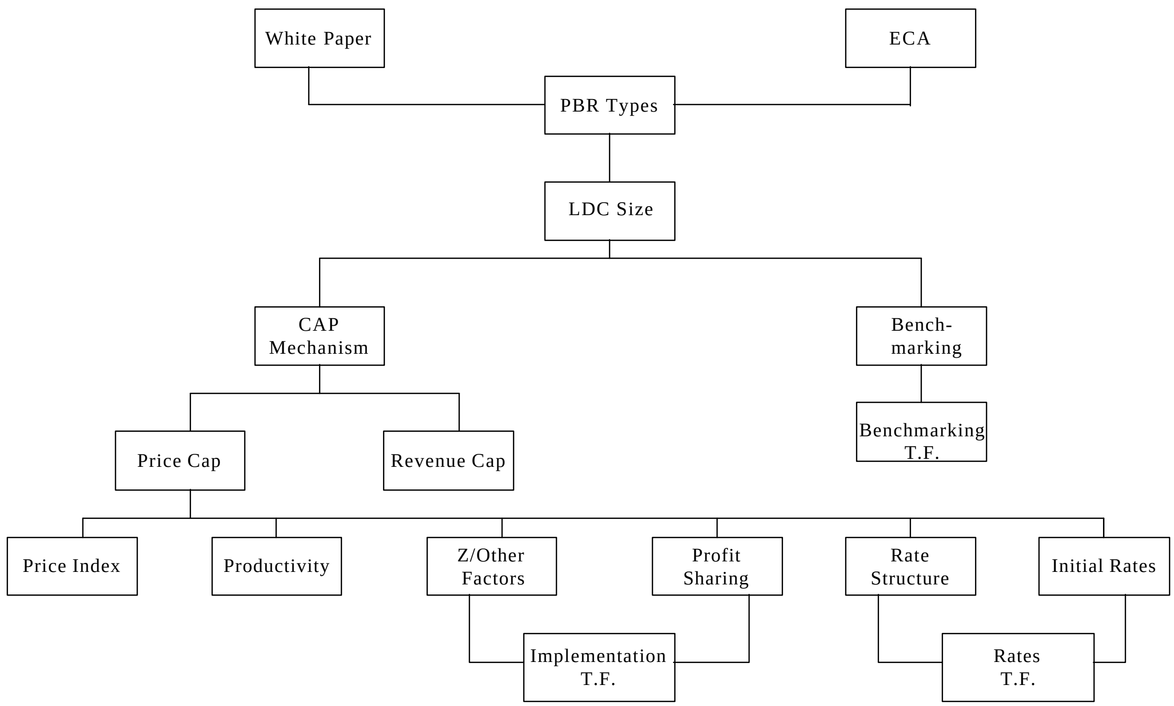
2.2 Approach

Chart 1 outlines the approach followed by the CMTF as well as the linkages to the other task forces. The process began with a consideration of the four basic types of cap mechanisms as discussed in the OEB's Staff Report, PBR Options For Electricity Distribution in Ontario (October 15, 1998) and also reviewed in the OEB Workshop, Performance-Based Regulation: Principles and Applications, conducted by J.M. Bauer and M.F. Wiley of Michigan State University in September, 1998.

The first distinction made among the alternative types of PBR mechanisms was based on pragmatic considerations. At the time of the formation of the task forces there were approximately 270 electricity local distribution companies (LDCs) in Ontario. These companies differed significantly in terms of size, cost structure and ability to bear a regulatory cost burden. Consequently, it was decided that there should be a distinction based on size for the application of alternative types of cap mechanism. Specifically, smaller LDCs and their customers would be better served by the use of a benchmarking procedure. The Yardstick (Benchmarking) Task Force was to concentrate its efforts on the development of a benchmarking methodology and the establishment of benchmarking sub-groups within the overall class of smaller LDCs.

The larger LDCs would be subject to one of the remaining three types of cap mechanisms. The question of the appropriate size cut-off was one that was discussed at length. Various criteria were considered, including asset size, revenues and number of customers. The consideration underlying the selection of a cut-off criterion is homogeneity of the impacts of the application of a cap mechanism. Specifically, it should not result in significantly different treatment in terms of

CHART 1
RATE REGULATION METHODOLOGY



regulatory burden, customer impact or return to capital among the LDCs covered by the mechanism. Although initially it was generally judged that a cap mechanism would likely apply to no more than perhaps ten LDCs, the specification of a particular criterion and a target number of LDCs was left to be decided later after preliminary quantitative assessment was completed. Appendix A presents the cap mechanism survey instrument.

In fact, the proposal of the Yardstick Task Force (see Report of the Yardstick Task Force) is that a cap mechanism should apply to all the utilities in the first generation PBR plan. This will allow time for the collection of data to establish a yardstick approach for the subsequent PBR plan (second generation PBR plan).

2.3 Selection of a Cap Mechanism

Each of the remaining three principal types of cap mechanisms was examined against the background of the set of principles established by the OEB for the implementation of PBR and described in the Staff Report referred to above. Each of the options has advantages and disadvantages. The price cap approach has the distinct advantage that it comes the closest of the three to replicating the process of competitive markets. The price of the final product in the market place incorporates the influence of changes in the price of factors of production and in productivity gains. The individual firm takes the price as given and attempts to maximize profits by controlling costs and/or achieving productivity gains beyond those that have been projected. This has the effect of reducing the volatility of prices compared to the revenue cap mechanism. The main drawback of a price cap PBR is that it leaves the LDC exposed to changes in energy throughput. Some have argued that the incentive for the utility to maximize throughput under the price cap mechanism is a drawback. On the other hand this may be seen as an effective use of available capacity. In any case, the impact of throughput variations can be mitigated through rate design and the use of profit-sharing mechanisms.

The revenue cap mechanism attempts to resolve the throughput problem associated with a price cap PBR. Instead of setting a price cap it sets a revenue cap. However, in resolving this problem it creates others. Specifically, once the revenue cap has been set the LDC has an incentive to set prices at levels that would under utilize the capacity of its system. This discretionary control over prices could also lead to greater price volatility. Moreover, the revenue cap mechanism requires throughput growth projections and the use of true-ups in the event of errors in any of the projections that make up the revenue cap. Perhaps, most importantly, it does not focus on the setting of relative prices and providing a set of incentives within this framework that encourages optimal efficiency.

Earnings-sharing or “sliding scale mechanisms” are closest to traditional cost of service/ rate of return (COS/ROR) regulation in that LDC performance is monitored in relation to return on equity (ROE) targets and sharing mechanisms are triggered when actual ROE falls outside a predetermined range. These plans involve a greater degree of regulatory oversight and incorporate fewer of the efficiency incentives than the other mechanisms. They are best seen as an adjunct to price or revenue cap schemes, used to mitigate extreme revenue distribution results.

After considering the pros and cons of the PBR optional mechanisms, the CMTF concluded that the price cap mechanism satisfies the greatest number of principles established by the OEB and, in particular, comes closest to meeting the objective emphasized in the White Paper of providing strong market-based incentives toward improved efficiency.

A position paper submitted by John Todd, Econalysis Consulting Services, on Cap Mechanism alternatives is presented in Appendix B.

2.4 The Price Cap Mechanism

The price cap mechanism provides an upper limit or cap to the price, or basket of prices, charged by an LDC and allows flexibility below the cap. It is designed to allow for the pass through of increases in the prices of inputs to the operations of the LDC and also for normal improvements in productivity in the industry. It may also be structured to allow for corrections of various sorts such as extraordinary events, the sharing of profits outside a pre-defined range, infrastructure investments and service quality adjustments.

The generic formula for the price mechanism is:

$$P_t = P_{t-1} \times (1 + I_t - X_t) + Z_t + Q_t + M_t$$

P_t = Price cap index
I_t = inflation index
X_t = productivity index
Z_t = extraordinary event adjustment factor
Q_t = service quality adjustment factor
M_t = profit-sharing adjustment factor

This formula presumes an initial price level that is escalated according to the factors indicated above. As Chart 1 shows the initial price level, along with the rate structure, are subjects for consideration by the Rates Task Force. The chart also shows that the adjustment factors, other than inflation and productivity, are being examined by the Implementation Task Force. The principal effort of the CMTF was then directed towards developing recommendations for the inflation and productivity factors.

3. THE INFLATION FACTOR

The objective of including an inflation factor is to allow for adjustment of the price of the final product to account for inflation in the price of factor inputs to its production. If price indexes for these inputs were readily available this task would be simplified. However, this is not usually the case and indirect measures of inflation are often used as proxies for the desired price index. Price indices that are commonly used are the Consumer Price Index (CPI), the GDP Price Index (GDPPI), and the Producer Price Index (PPI). The advantage of these indexes is that they are readily available. Unfortunately, since they measure different baskets of goods, they can diverge significantly over extended periods of time. Moreover, none of them measures input prices exactly, which can result in further distortions. For this reason a hybrid price cap mechanism that includes a profit-sharing adjustment is recommended.

3.1 Critical Elements of the Price Cap Mechanism

The economic theory underpinning price caps relates the change in distribution service prices (i.e., the prices of the utility's output) to the change in the unit costs of providing these services. The change in unit costs can be sub-divided into the change in the prices of inputs used in the production process (minus) the change in the utility's efficiency of combining its inputs into outputs. Thus, the change in the allowed cap for an LDC under price cap regulation equals the change in the industry's input prices minus the change in the industry's productivity comprehensively defined.

In implementing PBR, regulators must make three critical decisions with respect to the design of the price cap adjustment mechanism:

- How to operationalize the PBR cap adjustment formula;
- What index to employ to measure the change in utility input prices; and,
- How to select the appropriate benchmark for measuring productivity change.

Each of these issues is discussed below.

3.2 The Price Cap Formula

While one of the earliest (and most successful) implementations of PBR by the US Interstate Commerce Commission for railroads employed the straight forward expression relating the change in regulated output prices to the change in railroad input prices minus the change in railroad productivity, many of the subsequent implementations (in the US and U.K. and across several network industries) used an approach often labeled RPI-X (e.g., retail price index minus a productivity adjustment term, X). Unfortunately, this expression turned out to be incorrect.

Such implementations intended to express the utility industry's productivity performance relative to productivity performance for the national economy, since the price index (e.g., RPI) was a national output price index with the effect of national productivity change already reflected in it. However, this formula failed to include a positive adjustment to X reflecting the difference in the change in input prices between the regulated industry and the national economy. Since over this period network industry input prices were generally growing more slowly than economy-wide input prices, the X-factor specified by regulators was in effect lowered by 30 to 50 percent.

Recently, regulators have been specifying such "input price differentials" for inclusion in the RPI price cap adjustment formula. Such inclusion would then make the modified RPI-X approach theoretically equivalent to the simpler unit cost approach. However, the inclusion of national input prices and productivity indexes adds no additional information while at the same time introducing the possibility of substantial errors into the process [1].

3.3 The Input Price Index

The purpose of the input price index is to allow the utility to pass through changes in the prices of the inputs it purchases—at least up to the industry average change in input prices. Unfortunately, national economic accounts, are not necessarily structured to produce data with such regulation in mind. Therefore, a second important dimension of implementation relates to the trade off between price indexes published on a regular basis by government statistical agencies and the construction of an input price index specific to the industry in question. While the latter are somewhat more involved to construct, the use of national output indices which fail to measure inputs specific to the regulated industry (e.g., cables, distribution equipment) and the substantially lower weight applied to capital (if it is even included) means that such national price indexes may do a relatively poor job in a PBR plan.

National indices include the Consumer Price Index (CPI), the Gross Domestic Product Price Index (GDPPI) and the Industrial Producer Price Index (IPPI). What do these indices tract? The CPI measures the price of a basket of consumer goods and services. The GDPPI measures the price of goods and services sold to final users, e.g., consumers, government, trade and investment. Roughly 70 percent of the GDPPI is comprised of items tracked by the CPI. In fact, prices of noncapital business to business transactions (i.e., expensed items) are by definition excluded from the GDPPI. Finally, the IPPI measures the prices of a basket of producer goods. While the IPPI may come closest conceptually to the kind of index we need, it covers a sizeable number of commodities.

[1] The necessity of including both national input price and productivity indexes to correct for such errors means that these factors must also be specified for the term of the plan in one fashion or another.

Generically, an input price index (IPI) can be specified as:

$$IPI_1^t = \frac{\sum_{i=1...n} P_{it} w_i}{\sum_{i=1...n} P_{i1} w_i} ,$$

where the index covers the period 1...t, the inputs 1...n (e.g., labour, capital, materials) with prices P_i, and the weights w_i. Weights may be fixed (e.g., Paasche, Laspeyres, midpoint) or flexible (e.g., Fisher).

Initial analysis of the input price index indicates that a majority of the dozen MEUs examined to date had an observed annual average increase in their input price index between 1.6 and 2.0 percent versus about 2.7 percent for the Canadian CPI. Two other MEUs had input price increases that ranged from 2.7 to 3.0. These latter two MEUs had factor input weights significantly different then the majority. In one case, the utility was overweighted in labor and line losses[2] and underweighted in capital; in the second case, the small LDC was overweighted in labor and underweighted in capital. Additional research will examine alternative approaches to categorizing the cost structure of the LDCs. That is, basing our analyses on a functional (e.g., O&M vs. Capital) rather then factor input approach. In addition, research will examine the sensitivity of the input price index to alternative weighting schemes.

3.4 The Productivity Factor

The objective of the productivity factor is to account for the downward influence on the price of the final product of gains in output relative to all factor inputs. This is a physical relationship which is inherent in the production process of the LDC. Productivity refers to the creation of outputs in relation to the amounts of inputs into the production process. The use of particular inputs, such as labour, to measure productivity can be misleading, because different LDCs may

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[2] Line losses may be broken out and handled in a separate mechanism. This modification would decrease the annual average input price change by about 0.2 per cent.

use different ratios of labour to other factor inputs. Moreover, there is the problem of measuring heterogeneous factor inputs in physical terms.

For these reasons the measure of LDC productivity that is typically used for this purpose is Total Factor Productivity (TFP). TFP is designed to measure changes in output that cannot be accounted for by changes in all factor inputs. This incremental output could be due to changes in capacity utilization, economies of scale or scope, changes in technology or some combination of these.

Conceptually the total factor productivity measure is straightforward. Inputs and outputs are measured in real dollars. Changes in real dollar outputs that cannot be explained by the real dollar costs of inputs must be due to total factor productivity gains. In practice there are numerous problems in the application of this notion. For example, take the case of capital. Since a stock of capital is being used over an extensive period of time, the procedure for measuring its use generally starts in a period in which the oldest piece of equipment was put in place and then makes adjustments for usage and capital additions over time, again in real dollars. In practice the beginning point for the calculation of capital input into production is somewhat arbitrary, which contributes to problems of comparability.

Notwithstanding the measurement difficulties, the concept of TFP has been used extensively for the purpose of measuring electric utility productivity. For example, the Canadian Electrical Association has used TFP for many years to measure productivity trends among Canadian electric utilities. This has allowed the utilities to observe trends in industry productivity and also to compare their productivity gains against an industry benchmark. Indeed some of these utilities use this measure as an important element in assessing the effectiveness of their corporate plans.

The greatest problems in the use of TFP arise in the case where there are significant differences in structure between the entity being measured and the productivity benchmark. For example, there can arise important problems in the use of the measure to compare productivity trends among generators, which use different generation technologies. The more homogeneous the production process, the more accurate is TFP. Hence it would be particularly useful in the case of the "wires" business if all the entities measured were beyond some cut-off size. Additional research will examine the historical rate of productivity change among the

MEUs. Observed differences could be factored into the price cap plan by allowing the productivity offset to vary, say by size of utility.

Generically, a TFP index can be specified as:

$$TFP_1^t = \frac{\sum_{j=1...k} q_{jt} r_j}{\sum_{i=1...n} x_{it} w_i} ,$$

where the index period runs from 1...t, the inputs x_i with weights w_i, and the outputs q_j with weights r_j. The index can take alternative functional forms, including the Tornquist or Leontief.

Research will pay particular attention to calculating each LDCs capital input by revaluing pre- and post-benchmark year capital adjustments for each MEU. We will examine the implications of alternative functional forms. Observed productivity change across MEUs and subintervals will be examined as well.

APPENDIX A - CAP MECHANISM DATA SURVEY

B. Labour/Compensation, Capital and Miscellaneous Items

The following survey was distributed to the electricity distributors in Ontario on January 27, 1998:

The following information is required by year for a ten-year period (1988-1997, and 1998 if available). We have noted items that can be provided only if readily available and will not unduly delay submission of remaining information.

In addition the task force has identified a few additional items (#11 - #15) that need to be provided.

Labour/Compensation

1. Number of own full-time employees
2. Number of own part-time employees (If available)
3. Number of own FTE employees
4. Number of contract or outsourced “employees”(if available)
5. Total labour compensation (e.g. wages, salaries, pension, fringe, bonuses, etc.)
6. Total contract and outsourced labour expenses *(if available)*

The following information is required by year for a 25-period if possible, 197*3*-1998, but at minimum for the period 1977-1998.

Capital

6. Gross book value
7. Depreciation expense
8. Amortization expense
9. Retirements

10. Capital additions by the following categories or *aggregations of these categories:* Land; land rights; building and fixtures; generating assets; transmission line; transmission station equipment; distribution station equipment; sub-feeder overhead; sub feeder underground; distribution lines overhead; distribution lines underground; distribution transformers; distribution meters; sentinel light equipment; office equipment; computer equipment; store equipment; lease improvement; rolling stock; miscellaneous equipment; water heaters; load management control; system supervisory equipment; and sentinel lights.

11. Total Contributed Capital/Developmental Charges ($/year).

Miscellaneous Items

The following is required by year for the 1988-1997 period:

12. % Line Losses
13. Annual Cost of Power
14. a. Total Customers: Number, kWh, kW (billed) and Revenues
    b. Residential Customers: Number, kWh and Revenues
    c. General Service Customers: Number, kWh, kW (billed) and Revenues
    d. Large Use Customers (>5,000 kW): Number, kWh, kW (billed) and Revenues
15. Total Expenses (excluding generation expenses)

APPENDIX B - POSITION PAPER ON CAP MECHANISMS - PREPARED BY JOHN TODD, ECONALYSIS CONSULTING SERVICES

As discussed at the last Cap Group meeting, this memo sets out a few considerations that might be relevant in deciding whether to cap the prices or revenues of Ontario electric distribution utilities. For purposes of these comments I have assumed that the same methodology will be used for all utilities, although the productivity offset, and possibly other factors in the cap formula may be determined in different ways (e.g., company specific factors for the largest utilities and the yardsticking approach for other utilities).

Three considerations are addressed in this memo:

- the stability of income,
- the degree of diversification, and
- the stability of costs.

The Stability of Income

In the new world of corporatized electric distribution utilities, there will be an increased focus on the rate of return being earned by MEUs. Each company will have an allowed return on equity which will be determined in part by the financial risk faced by the corporation. Anything that increases financial risk, will increase the return on equity needed to compensate the owner for bearing that risk. In turn, higher risk will result in higher prices for distribution services.

Price cap regimes are designed to maintain stable prices. Although price discontinuities may occur in extraordinary circumstances (e.g., Z-factors), the general expectation is that prices will adjust smoothly, at a rate that reflects inflation and a fixed productivity offset.
With stable prices, total revenues will be stable only if the volume of services sold is also stable. Hence, under the current approach to pricing for small volume customers (a small customer charge with most of the bill based on usage), revenues will be sensitive to any factor that affects demand, although costs may be virtually fixed. In particular, any MEU with a significant share of

heating customers can expect to see much larger fluctuations in its revenue than in its costs. This situation creates financial risk for the investor.

There will be clear benefits to reducing this financial risk. For example, kWh charges for distribution services could be replaced by fixed customer charges. Since the number of customers is far less volatile than power sales, this change would significantly reduce variances in total revenue and income. Unfortunately, price cap regimes are not well suited to changes in the basis on which prices are charged. It is difficult to apply a price cap formula from one year to the next if power is sold on a kWh basis in the first year and on the basis of a fixed customer charge in the next year, for example.

Any transition will be complicated by the practical reality that the impact of replacing kWh charges with fixed customer charge will have significantly different impacts for different customers. Customers with relatively high power consumption (e.g., heating customers) may enjoy significant lower charges for distribution, while customers with minimal power requirements may experience very high percentage increases in their bills.

A common way to mitigate the impact of such a transition, and to reduce customer resistance, is to phase in the change. However, it will be particularly difficult to accommodate MEUs moving from kWh charges to customer charges during the term of the price cap if the change is phased in. Indexing changes in prices during such a transition will be complicated. The benefits of simplicity and transparency that are normally attributed to price cap regimes will be lost.

An alternate way to address the concern would be to cap revenues rather than prices. The MEU would then face little uncertainty about the total revenue it would receive, and would be able to manage its costs accordingly. Financial risk would be reduced.

Furthermore, a transition from kWh-based rates to customer charges could be easily accommodated. Furthermore, the changes could be accommodated either by capping total revenue, or by capping revenue per customer. The latter approach would also mitigate risk related to uncertainty with respect to customer additions, which is important given the sensitivity of costs to the number of customers.

The Degree of Diversification

It should be noted that the financial risk inherent in a price cap mechanism where volume is uncontrollable and volatile (kWh as opposed to customers) will be less for a diversified company (multiple sources of revenue that are not highly correlated), than for a small undiversified distribution utility. In diversified companies, the portfolio effect reduces the risk related to variances in the revenue in each area of operations. Hence, another way to reduce the risk noted above would be for independent MEUs to amalgamate into large diversified entities.

Taken from the other perspective, the case for capping revenue rather than prices, will be stronger until the structure of the industry has been transformed into one with much more concentrated ownership. It may be worth considering implementation of a revenue cap mechanism for a transitional period as amalgamation proceeds, and rates are restructured. Implementing price caps immediately may result in changes being driven by the cap mechanism, with the goal of reducing financial risk, rather than changes being made in response to commercial and market forces.

The Stability of Costs

A further consideration that may affect the financial risk associated with the new cap regime is the lumpiness of many capital investments. Revenue caps will result in stable revenue; price caps will result in stable prices and stable revenue if quantity of services being sold (kWh or customer-distribution) is also stable. However, stable revenue will not result in a stable return on equity and low financial risk if costs are volatile.

In small MEUs, both operating and capital costs can be significantly affected by uncontrollable factors, such as severe storms (ice damage) and infrequent major capital improvements. In either case, corporatized MEUs that focus on the earned return will avoid incurring significant costs that cannot be matched by corresponding revenue increases.

The detrimental impact of “lumpy” costs on financial performance could force small MEUs to defer large maintenance expenses, even if those expense are prudent. In addition, large capital expenditures, to facilitate long-term growth for example, may be avoided. In other words, normal commercial decisions may be skewed by the regulatory system.

Mechanisms, such as Z-factors and off-ramps, can be incorporated into either revenue or price cap mechanisms to reflect these periodic lumpy expenditures. However, this approach raises the burdensome task of monitoring and differentiating between expenditures that should receive special treatment and those that should not.

An alternative approach would be to cap revenue by escalating operating costs using a fixed adjustment formula (growth + inflation - productivity offset), while maintaining a rate base that reflects actual capital expenditures, subject to certain pre-set guidelines. Periodic major capital expenditures could be built into the approved rate base. Unusual maintenance costs (e.g., ice storm) could be treated as capital expenditures. Taking this approach would build flexibility into the mechanism, while minimizing reliance on Z-factors and off-ramps, which can be cumbersome to administer. It may be noted that this is the approach used by the British Columbia Utilities Commission for the West Kootenay Power PBR mechanism, as well as for BC Gas.

Conclusion

Although almost any challenge can be accommodated within a price cap mechanism, one of its features is that it offers a simple and transparent approach to regulation. As complexity is added to address practical considerations such as those identified in this memo, this simplicity and transparency can be compromised. Unfortunately, price caps tend to raise customer expectations that rates will change in a stable and consistent way. A more flexible price cap mechanism can run into difficulty when the reality conflicts with the expectations of customers. As a result, to avoid customer confusion and resistance, it may be desirable to use a mechanism other than price caps unless the price cap mechanism can be kept very simple, with few exceptions that result in rate increase that differ significant from the normal cap rate.