PBR OPTIONS FOR

ELECTRICITY DISTRIBUTION

IN ONTARIO

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PBR OPTIONS FOR ELECTRICITY DISTRIBUTION IN ONTARIO

1. INTRODUCTION

This report presents an overview of performance-based regulation ("PBR") and its potential application by the Ontario Energy Board ("Board") to regulate the electricity distribution sector in Ontario. The Board has stated its intent to explore PBR as a regulatory tool within the energy industry using a sector-specific approach. This Board Staff paper examines PBR options for one of those sectors; namely, electricity distribution.

Though the Board seeks to apply a sector-specific approach to regulation, there may be competitive effects between the electricity and natural gas sectors that result from regulation and must be balanced. The Ontario government is currently in the process of restructuring the electricity power industry. Efforts have been underway for several years to restructure the gas industry. Clearly, the circumstances surrounding the energy industry are changing, and change will bring different incentives for the participants in the Ontario network industries, new regulatory oversight, and new regulatory tools.

1.1 BACKGROUND

The Ontario Government released its White Paper on the restructuring of the electricity industry, entitled *Direction for Change* on November 6, 1997 in which it proposes retail competition for electricity. It also indicated that it would direct the Board "to examine, advise on, and subsequently implement a performance-based approach to regulation that ensures efficiencies are achieved in the monopoly parts of the industry and result in benefits to the customers". The monopoly parts of the industry are the delivery components: transmission and distribution.

Bill 35, the Energy Competition Act (the "Act") was introduced in the Legislature on June 9, 1998. Upon proclamation, the proposed Act will create a fully competitive electricity market and expands the Board's regulatory responsibility to the monopoly delivery components of the electricity industry in addition to its current responsibilities over the natural gas industry.

Current legislation restricts the Board's rate regulation methodology to the determination of a reasonable return on rate base. Bill 35 proposes that the Board should be given flexibility in adopting a method or technique it considers appropriate in approving or fixing just and reasonable rates. If the proposed Act is passed, it will allow the Board to practice PBR as proposed in the White Paper. The gas utilities have also expressed interest in moving towards PBR.

With the expected enactment of the proposed Act, the Board is considering the implementation of PBR in its regulation of the gas and electricity delivery companies (the utilities). The objective of the Board's practice of PBR will be to encourage efficiencies in the monopoly sectors of the energy industry which should result in benefits to customers in terms of lower rates, without sacrificing service quality.

1.2 THE REGULATORY CHALLENGE CONFRONTING THE BOARD

With the implementation of Bill 35, several new challenges will confront the Board in its regulation of the "wires" business in the Province. First, the Board will be responsible for regulating a large number of electric distribution companies (at present there are approximately 270 electricity distribution utilities). These entities vary widely in size and function. Ontario Electricity Service Corporation, through one or more subsidiaries, will inherit all the distribution assets of the present Ontario Hydro, which includes over 1 million customers. The municipal electric utilities range in size from under 200 to over 500,000 customers. Over 100 of the current utilities have fewer than 1,000 customers. Clearly, the challenge is to find a regulatory mechanism that fits the diversity of size, industry capabilities, and geography, while maintaining the economic balance among these entities.

Second, most of the electricity distributors will have both regulated and unregulated functions. The gas distribution utilities through affiliates, already engage in a number of competitive functions, including sales of equipment, sales of gas, and contract provision of services. The municipal utilities will also have regulated wires functions and unregulated competitive electricity supply and services functions. The form of these functions, and their relations to each other, are currently under discussion at the Market Design Committee.

Third, the introduction of greater choice and competition in the industry is likely to change the nature of distribution and transmission. Some customers are likely to wish to bypass the transmission and/or distribution network. New technology, such as telephony over electric distribution wires, will result in new competitive offerings integrated into the monopoly functions. Transmission companies (both electric and gas) are likely to develop new competitive lines of business, such as fiber optic based communications systems.

Therefore, a regulatory system must be designed and put in place to: (1) fulfill the new responsibilities the Board is assuming; (2) provide the flexibility the Board needs to meet the changing circumstances of the market place; (3) efficiently deal with the large number of entities to be regulated, and; (4) protect the public interest. Such a system can be structured using components from PBR.

1.3 WHY PBR?

Economic regulation attempts to produce, in a concentrated or monopolistic market, the same pricing that competitive markets exhibit. Current regulatory practices and methods to achieve this have evolved over a number of years. Most common is cost of service/rate of return ("COS/ROR") regulation.

While COS/ROR regulatory practices have historically proved reasonably effective at achieving important public policy objectives, changes in both energy and other network-based industries has increasingly led many to conclude that COS/ROR regulation may be too slow, too rigid, and too complex. Restructuring and deregulation require a regulatory framework that is more responsive, more flexible and more transparent.

COS/ROR regulation establishes a fundamental link between the regulated firm's prices and its costs. While this link is generally viewed as the basis of equitable rates, tying each firm's prices to costs diminishes the firm's incentives to reduce costs and increase market responsiveness, since gains from these efforts will accrue largely to ratepayers, not shareholders. The firm's incentive to innovate is also attenuated since prices are based, not on value, but on costs; in addition, prudence reviews might disallow some of these expenditures. Thus, the firm's gains from innovation are constrained relative to its potential costs.

COS/ROR regulation becomes increasingly problematic as markets become more competitive because it does not normally allow the regulated utility sufficient pricing flexibility to respond to market-based competitors for all or part of its services. Lack of such flexibility, if for example, gas and electricity are close in price, might encourage some customers to migrate to competitive providers and increase the per-unit cost for remaining customers. Provision of services in transition from monopoly to competitive markets by regulated firms also increases the concern of competitors regarding the potential for cross subsidization.

In a competitive market, firms are driven to improve efficiency by two reinforcing tendencies. First, the internal motivation from the fact that improvements in efficiency allow the firm to reduce its costs and to benefit from increased profits and/or market share in the short and intermediate time frame. Continued improvements in efficiency may confer significant long run advantages relative to competitors. Second, the (constant) external motivation from the fact that its competitors will strive to improve their own efficiency, performance and market share at its expense.

PBR can overcome some of the limitations associated with COS/ROR regulation, especially those associated with a deregulated market where customers may choose their supplier. It is argued that PBR can better meet the needs of the major stakeholder groups: regulators, firms, and consumers.

- Regulators require a framework that provides incumbents with incentives to operate efficiently and innovate. PBR fits this criterion. It also gives consumers appropriate price signals, and allows sharing in the gains from more efficient production, consumption and innovation.

- Incumbent operators require a regulatory framework that allows them to make the transition to a more competitive environment for their non-monopoly business activities with an environment with increased rewards as well as risks. PBR is a framework that permits greater pricing flexibility and allows the potential for higher profits based on superior performance. PBR allows the firm rewards from innovation and provides a planning horizon (term of PBR plan) during which the mechanism for calculating price changes and retained earnings are generally fixed.

- Consumers would benefit from a regulatory framework that increases the connection between the prices they pay and the potential for increased gains from operating efficiencies and innovation. PBR can bring the benefits of increased competition, but preserve the important service, reliability and safety standards achieved under COS/ROR regulation. PBR also provides some assurance that prices for non-competitive services will not be raised to allow prices for competitive services to be lowered.

1.4 ORGANIZATION OF THE PAPER

The remainder of this paper presents a discussion of the issues surrounding PBR implementation by the Board. Three items bear special mention. First, some plan design issues such as term (i.e., the duration the plan is in effect), standards, excluded factors, or profit sharing cut across all PBR approaches. Second, many implemented PBR plans combine aspects from several PBR approaches. Finally, given the scope, timing and complexity of the specific issues involved in implementing and administering a PBR plan by the Board, practicality must be one of the primary considerations.

Section 2 discusses the important changes taking place in the electricity and gas markets within Ontario. Section 3 presents the Board's PBR principles. The most widely implemented approaches to PBR are each discussed in section 4 including important design features and similarities and differences between the approaches. Section 5 details issues that should be considered for successful implementation of PBR. Finally, a number of PBR case studies are presented in the Appendix to this paper.

2. THE ONTARIO ELECTRIC AND GAS MARKETS AND IMPLICATIONS FOR PBR

2.1 BOARD REGULATION OF GAS DISTRIBUTION

Ontario utilities have largely unbundled gas service, separating monopoly functions from the gas commodity function. Choice of gas commodity supplier is available to all customers in the Province.

The Board currently regulates the rates of three investor-owned local distribution companies (Enbridge Consumers Gas [formerly The Consumers' Gas Company Ltd.], Union Gas Limited, and Natural Resource Gas Limited). The current *Ontario Energy Board Act* (Section 19) limits the Board's rate regulation of gas utilities to COS/ROR.

The Board establishes rates for each utility following a public hearing. Where users purchase gas directly from the suppliers, the Board fixes the rates that utilities may charge for transporting, storing, and distributing the gas, and establishes the buy/sell reference price.

In setting rates, the Board establishes the utility's rate base. The Board also determines what rate of return the investors should have the opportunity to earn, and the revenue required by the utility to pay its expenses and make the allowable return. The Board reviews the utility's cost allocation and rate design methodology that determines how each customer class should contribute to meeting the revenue requirement.

The Board's primary objective when setting rates is to ensure that the public interest is served and protected. The Board sets rates as low as possible while providing utility investors an opportunity to earn a fair return.

A main rate application case involving a public hearing, a written Board Decision With Reasons, and the issuance of the Board Rate Order to the applicant can take up to nine months from the date of application to issue of rate order. The pre-hearing portion involving filing evidence, interrogatories, and settlement meetings takes six months of this time.

2.2 CURRENT REGULATION OF ELECTRIC DISTRIBUTION COMPANIES

The retail electricity distribution system in Ontario now consists of a large number of municipally owned distribution utilities (about 270), the retail distribution arm of Ontario Hydro, and several privately owned utilities. Ontario Hydro regulates the municipal utilities and the other electricity distributors that it supplies.

Ontario Hydro is a provincially owned vertically integrated utility, which is not regulated by the Board. The Board, upon reference from the Minister of Energy, Science, and Technology, does hold hearings on Ontario Hydro bulk rate proposals, and makes non-binding recommendations to the Minister and to the Ontario Hydro Board of Directors. The Ontario Hydro Board has final rate-making authority.

The method used for regulating municipal distribution utilities by Ontario Hydro is COS/ROR with an all-utility average cost of service model used by the utilities in their rate derivations. The utilities are not required to file their own cost of service study and very few utilities have conducted such a study. The regulatory process is administrative, without third-party review or public hearings. The process is generally formula driven through financial and rate guidelines set by Ontario Hydro.

The financial guidelines set maximum caps on revenue limiting criteria: rate of return on rate base and working capital as a per cent of net operating expenses. Electricity distribution in Ontario is almost entirely publicly-owned and the return earned by the public utilities is used to finance capital projects and to retire debt. The rate guidelines are intended to produce rates that are equitable and minimize cross-subsidization between rate classes according to the all-utility average cost circumstances reflected in the cost of service model.

Under current legislation, a municipal utility may serve all or part of the geographic area of its municipality. It has an obligation to serve all retail electricity customers in the serviced area. A municipal utility may not directly serve customers in another municipality; it can only do so under contract to the utility for that municipality.   If two municipalities amalgamate, their utilities must amalgamate. Utilities may not amalgamate if the municipalities do not.

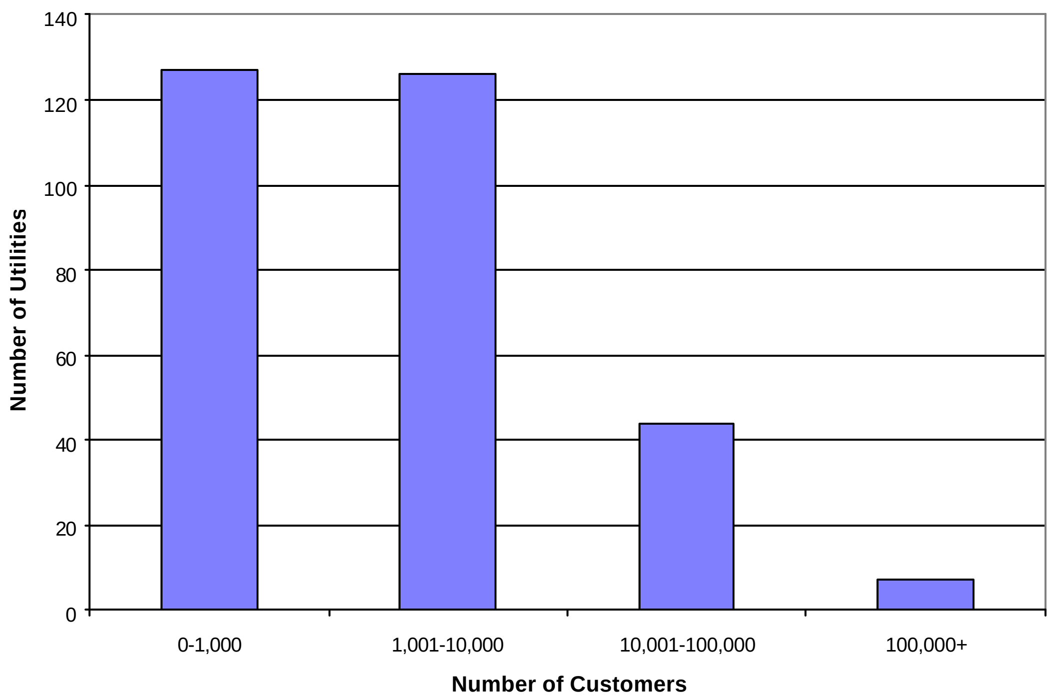
Under Bill 35, these rules will change. The entities will become business corporations, initially with the municipality as the single shareholder. The proposed legislation does not prevent their subsequent sale to a third party subject to approval by the Board. Further, under Bill 35, the utilities will require a license from the Board.

The Diversity of the Municipal Electric Distribution Companies

The Board, in anticipation of the passage of Bill 35, is confronted with the significant challenge of devising a flexible regulatory framework for a group of distribution utilities which differ widely in size, cost characteristics, and many other attributes.

Figure 1 displays the diversity in number of customers of the municipal utilities in 1995. There were only 13 utilities with more than 50,000 customers. The average number of customers was 9,500, and over 100 utilities had fewer than 1,000 customers. Clearly, the majority of utilities in the Province are relatively small.

Figure 1 – Size Distribution of Municipal Utilities in 1995



The municipal utilities show a similar wide range of costs. Total variable expense per year (operations and maintenance, billing and collection expense, and administrative expense) per customer varied from $50 to $440 in 1995. About half of the utilities had costs in the range of $150 to $220.

The utilities also have a wide range of price/cost margins. On average, the cost of electricity supply and transmission accounted for 87% of the total revenue, indicating that distribution utility operations and profit were only about 13% of the total. There were also wide variances in this ratio. It ranged from a high of about 95% to about 74%.

2.3 IMPLICATIONS FROM ELECTRICITY INDUSTRY RESTRUCTURING

Currently, the Ontario Government is restructuring the electric industry, introducing competition into wholesale and retail electricity sales. It is anticipated that the transmission and distribution "wires" business will remain monopoly functions, although certain distribution functions (such as metering) may become competitive services.

The change in regulatory responsibilities of the Board, as well as the changes in the Ontario energy market structure, mean that a new regulatory regime must be developed for application to the remaining monopoly functions.

3. PBR PRINCIPLES

The Board has developed a set of principles for the implementation of PBR that capture these changes and responsibilities.

1. The PBR framework should address all specific requirements of the legislation and regulations.

2. The PBR framework should protect customers and result in prices for regulated services that are just and reasonable.

3. The PBR framework should discourage cross-subsidization between regulated and competitive services.

4. The PBR framework should encourage greater economic efficiency by providing the appropriate pricing signals and a system of incentives to maintain an appropriate level of reliability and quality of service.

5. The PBR framework should permit the utility an opportunity to earn a reasonable return on shareholder capital and to maintain its financial viability.

6. The PBR framework should be transparent and as simple as possible. The cost of administering PBR, inclusive of the costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available from PBR.

7. PBR should allocate the benefits from greater efficiency fairly between the utility/shareholder and the customers.

8. A PBR framework should be flexible and able to handle changing and varied circumstances.

9. The PBR framework should facilitate the use of efficient processes.

4. APPROACHES TO PERFORMANCE BASED REGULATION

This section briefly describes the most common PBR approaches and the critical design issues associated with the use of PBR.

4.1 OVERVIEW

In the abstract, PBR approaches are appealingly simple to understand and administer. However, experience with actual implementation in different countries, industries, and time frames, has demonstrated that the appearance of simplicity can be deceptive. Therefore, the design of a PBR plan should give careful consideration to such design features as incentives, constraints, standards, terms, sharing and pass-throughs. There are four types of PBR models that have been widely considered or implemented:

- Price Cap regulation
- Revenue Cap regulation
- Benchmark or “Yardstick” regulation
- Sliding Scale regulation

Price or revenue caps are probably the most common types of PBR in use today. Under cap mechanisms, changes in price indices (such as national or industry-specific indicators) drive permitted changes in output prices or revenue for regulated services. These allowed rates of change in price or revenue of the regulated service are generally further reduced by productivity offsets (often called the X factor) that account for industry trends and provides for productivity improvements. Establishing an appropriate price index and X factor requires strong familiarity with price index theory and index calculation. Whether a broad price-cap mechanism (change in aggregate price index minus an X factor) or a more refined industry-based mechanism (i.e., industry specific input price and total factor productivity indices) is used can be critically important.[1] In addition, price and revenue cap plans provide potentially different incentives on pricing and sales but generally similar incentives on costs. With price and revenue caps, pass through costs for extraordinary events that are outside of the control of the utility are accommodated through a Z factor. In addition, growth factors are generally included in revenue caps.

Yardstick or benchmarking regulation simply uses information on industry, sub-industry, or peer group cost performance to establish a benchmark price for each firm in that group. Of particular

[1] Confusion about the correct application of offsets has sometimes resulted in price-cap formulas that distort the earnings of regulated firms. That is, many PBR plans have not correctly adjusted aggregate indices for input price differentials or correctly benchmarked aggregate productivity.

importance in implementing yardstick regulation is the requirement that each firm be benchmarked against a peer group of similarly situated and structured firms. Otherwise, inappropriate comparisons due to intrinsic cost differences could create inter-firm inequities in establishing benchmark prices.

The sliding scale approach to PBR simply sets a cap on earnings beyond which excess earnings are shared between ratepayers and shareholders according to a pre-set formula. This approach is probably the least difficult of the three described here to administer, but requires careful consideration of the appropriate threshold earnings level and split of excess earnings. The level of earnings at which sharing begins and the level of sharing can impact firm behavior and investment decisions. Furthermore, the existence of earnings sharing in PBR plans in general can act as a backstop in the event the PBR plan results in “unanticipated earnings.”

Many regulators are uncomfortable with PBR plans to the extent that they might encourage “excessive or inappropriate” cost cutting unless firms are constrained to consider appropriate service standards. PBR regulation should provide more explicit accounting for non-price or productivity incentives by linking allowed returns to standards in any of several areas deemed important to service quality and reliability. While this approach can be data intensive, in that it usually requires developing and tracking industry and individual firm performance in the targeted areas, it can help ensure that PBR induced gains in cost and efficiency do not come with associated degradation in service quality, reliability, or safety. It also requires careful consideration of the allowable increases/decreases in returns resulting from performance against these benchmarks.

Some PBR plans combine aspects of these approaches, in effect, creating a custom-tailored mechanism to better handle regulatory objectives and concerns. For example, price cap plans can be constructed to include earnings sharing and performance standards. Certainly, experience with PBR implementation has indicated the growing concerns of regulators to require management to appropriately factor performance, quality, or service standards into its operations.

4.2 PRICE CAP REGULATION

In price cap regulation prices are capped independent of costs. The test year’s price caps are set to the price of the previous year indexed by an inflation factor offset by a productivity factor. Extraordinary events (Z factors) are taken into account in setting the price cap.

Price caps are a form of utility regulation that focuses initially on controlling prices directly, rather than indirectly as under COS/ROR regulation. Under COS/ROR regulation a utility’s prices for services are the result of controls on cost-based revenues – i.e., prices are set to recover expenses and returns to capital. The allowed rate of return fixes the ex-ante profits of the firm and, together with expenses, establishes the firm’s revenue requirement. Prices are “simply” required revenue per unit. Over time, deviations in actual profits may ultimately lead to adjustments in such prices.[2]

On the other hand, price cap regulation controls prices for services directly. While some constraints on profits may limit realized returns significantly above or below the plan's expected return, within these upper or lower bounds the utility has flexibility to set or change prices as long as the resulting price satisfies the plan's constraints.[3] Thus, there is the incentive for the utility to operate more efficiently, since costs savings, new services or greater market responsiveness which increase the firm's profits can be retained by the firm subject to the plan's constraints.

How do price cap plans actually work? Typically, following the establishment of initial rates, a price cap plan provides for the periodic adjustment of output prices much as in a competitive market. In a competitive market, changes in the prices of inputs purchased by producing firms tend to be passed through to customers to the extent that improvements in operating efficiencies (by the producing firms) cannot offset such changes. Likewise, in a price cap plan, adjustments to maximum prices (i.e., cap or ceiling) are determined by an index, which simulates the competition market process – changes in input prices net of changes in productivity. Thus, higher price inflation increases the output price cap and higher productivity lowers the output price cap.

Actual price cap plans have utilized a number of price indices to represent input price inflation. In theory, the index should represent the change in price of the inputs purchased by the regulated firm (e.g., a weighted average price of items "purchased" by say the subindustry LDC, including labor and capital). In reality, tradeoffs exist among the potential "inflation" indices. For example, regularly published government price indices may not include the industry or subindustry in question, or if published, may be released with a substantial time lag, say one, two, or even three years late. On the other hand, regularly published government price indices which are released on a timely basis may be inappropriate due to their focus on consumer purchases or other broader market/economic measures.

In selecting among the input price index options, such considerations must be carefully balanced. Stakeholders must be confident that the measure is accurate, timely and cost effective. Research may be needed to develop a specific price index for each regulated sector from company and /or government data or to ascertain that existing published price indices are, in fact, suitable.[4]

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[2] Of course, the scenario depicted here is highly stylized for descriptive purposes. Regulators may examine prices for their appropriateness in whole or in part through the rate design process.

[3] Typically, price flexibility allows the firm freedom to choose between the upper bound cap and the lower bound, often set at incremental cost.

[4] In fact, some plans have used such research to develop an adjustment factor reflecting an industry's unique characteristics which is then applied to broader based price measures for the term of the plan. This approach combines readily available and timely information on broader price changes with industry specific differences.

Similarly, actual price cap plans have utilized a number of approaches to determine the change in productivity among the regulated firms. In some cases, a negotiated process was employed. In other cases, government statistical measures provided the required information. Finally, in some cases data from the companies was employed to gauge the recent or expected improvement in productivity. In fact, most plans combine several approaches in determining the size of the productivity "offset." As with the price index, tradeoffs exist among these approaches: accuracy, timeliness and cost effectiveness must be carefully balanced.

It is noted that the actual productivity offset selected should be based on peer group, not individual firm performance. A firm which improves its productivity more than the peer group standard imposed in the plan can retain the increased earnings associated with its superior performance (within the provisions of the plan). Since each firm is similarly incented to improve relative to the peer group average, the rate of productivity change should increase over the term of the plan, assuming sufficient time for the firm's investment to payoff.

However, application of a price cap approach to network-based energy utilities may entail two potential disadvantages, which must be considered. Both of these disadvantages tend to be mitigated in revenue cap plans discussed below. First, price cap regulation tends to encourage increased sales by the utility since prices, but not quantities, are constrained under the plan. This incentive, in some circumstances, may be inconsistent with energy efficiency objectives. Such incentives to increase sales can be tempered through a variety of plan design features. For example, an earnings sharing mechanism reduces the firm's incentive to increase profits in general. Thus, although not specifically designed for this purpose, earnings sharing could be used in combination with price caps. As a second option, regulators could include energy efficiency objectives, which reduce sales quantities and their associated rewards/penalties among the performance standards included in the plan. Finally, regulators could include expenditures for energy efficiency programs among the Z factors in the plan (i.e., cost pass throughs).

Second, price cap approaches may potentially be less suitable in cases where the regulated firm has high fixed costs and faces volatility in revenues beyond its control. For the network industries under price cap regulation, significant declines in energy throughput can result in revenue shortfalls without corresponding decreases in network costs.

4.3 REVENUE CAP REGULATION

With a revenue cap the test year's revenue is capped independent of the utility's costs and is set according to the previous year's revenue indexed by an inflation factor adjusted by a productivity factor. Extraordinary events and growth are factored into the revenue cap.

Of course, such applications assume that differences in prices between the aggregate and industry specific measures remain fixed over the term of the plan.

Revenue caps are similar to price caps except that revenue is adjusted by changes in input prices net of changes in productivity. In some plans, allowed revenue is also adjusted to reflect changes in the number of customers. The incentive provided a regulated firm to reduce costs under a revenue cap is similar to that provided by a price cap. Furthermore, all of the issues raised in the discussion of price caps with respect to price indices, productivity offsets, standards, sharing and term hold for revenue caps. However, revenue caps differ from price caps in reducing both the incentive and risk associated with sales.

Since under revenue caps a firm's allowed revenue is constrained, the firm's incentive is to reduce not only unit costs (say average cost per unit output), but also the number of units sold such that total profits are maximized. Thus, revenue caps may be intrinsically more compatible with energy efficiency programs which reduce demand, than are price caps. Similarly, variations in sales due to factors beyond management's control, e.g., customer migration may not cause the utility to suffer severe financial distress.

This pricing feature of revenue caps has been criticized since it may also encourage the utility to raise its prices, thus reducing sales to stay within the revenue cap, and maximizing profits. Other theoretical criticisms maintain that price caps are more efficient in setting relative prices and that pricing in general under revenue caps is more variable. Therefore, some analysts have suggested combining features of both price and revenue cap plans to offset the relative disadvantages of each approach separately. Thus, one could specify a revenue adjustment within a price cap plan or a price adjustment within a revenue cap plan.

4.4 INDUSTRY AVERAGE COST OR "YARDSTICK COMPETITION" APPROACH

In situations where the regulator is confronted with the task of regulating a large number of companies, each employing generally similar technology to produce a product or service, and servicing potentially dissimilar markets (e.g., urban vs. rural, residential vs. industrial/commercial) the Yardstick Competition ("YC") approach can be effective. The key element of this approach is the use of industry or appropriately partitioned subgroup cost/performance measures to create external peer group benchmarks.

For example, firms could be partitioned into peer groups (e.g., small, rural operators). If the external benchmark were the average cost of the peer group, then each firm could charge an average price equal to the peer group's average cost.

Each firm would have an incentive to lower its own costs, since to do so would increase its profits relative to the price ceiling established on the peer group's average cost. Over time, efforts by each firm to become more efficient would result in decreases in costs and consequent reductions in the price ceiling. Each firm would have an incentive to service new customers or offer innovative services if the associated additional activities increase earnings.

This approach to PBR aims to set up an efficiency tournament within the peer group of regulated firms. Each firm is “forced to compete” with respect to efficiency and responsiveness; whether or not it faces any actual competition in its product or service markets. In designing such forms of regulation, however, it is important that the “simulated” competition be among similarly structured firms. That is, it is necessary to control for intrinsic differences in cost conditions among firms. Such intrinsic differences might relate to a firm’s size, customer density, or end-user load characteristics, for example. These intrinsic differences would presumably remain even if all firms operated at peak efficiency.[5] Thus, such differences need to be identified and controlled through the careful selection of subgroups and assignments.

Typically, intrinsic cost differences are accommodated in the YC approach by a multi-phased implementation process that places each firm in a tournament with similarly situated firms. First, all firms would provide information on market and customer profiles, operations, revenues, rates and costs. Second, statistical modeling of this information would identify and quantify intrinsic cost differences. Delphi techniques (expert committee judgment) can be used as an alternative or to augment or confirm the results of the statistical analysis. Results of step 2 (identifying intrinsic cost characteristics) can be used to create a set of subgroup classifications for review. Third, the subgroup characteristics defined in step 2 can be applied to the information supplied by each firm in step 1 to create peer group assignments for all firms. Fourth, information provided in step 1 would be used to calculate average costs for each peer group. These average costs by peer group would be established as external benchmarks for each firm’s average price.

Periodically (e.g., annually), updated information would be collected to establish new benchmarks and gauge performance under YC. Periodically, although possibly not each year, it would be useful to reexamine each firm’s subgroup assignment to ensure that structural changes in firms’ markets, end-users, or operations were appropriately reflected in peer group assignments. At some point, it would also be useful to re-examine the identified intrinsic cost characteristics and the subgroup classifications.

4.5 THE SLIDING SCALE APPROACH

Sliding scale mechanisms track the utility’s realized profits and “share” with ratepayers some or all of the earnings that “fall” below or above certain plan thresholds.[6] Typically, the zone between these thresholds is termed a “dead band” and the utility and its shareholders are “at risk” for results within this zone. Such dead bands are designed to maximize the firm’s incentive and better match risk and rewards. Earnings above or below these thresholds are shared with

[5] While some firms may in fact have some control over end user loads and profiles, these are presumably relatively fixed in the short run.
[6] From an implementation perspective, this is accomplished by adjusting future rates to eliminate the “excess” in profits.

ratepayers under varied and sometimes complex pay-out formulas. Performance substantially outside of the dead zone may also trigger automatic reviews.

Earnings sharing can be and often is combined with the PBR approaches discussed above or with other incentive modifications to a COS/ROR framework. For example, earnings sharing has been employed together with a rate freeze to utilities under COS/ROR regulation.

Here again, regulators must balance the utility's reduced incentive as a result of sharing with the greater "insurance against undesirable outcomes" afforded by this feature. While the sharing mechanism can reduce the firm's incentive by reducing its reward, it can also act as a backstop for inadequacies in plan design or implementation. For example, unusually high earnings could be due to poor plan design that rewarded mediocre as well as superior performance. Even if "deserved," unusually high earnings can still cause a perception problem, reduce commitment, and ultimately, induce regulatory backlash. On the other hand, poor performance can potentially undermine a utility's commitment to quality/reliability standards and even to the concept of PBR itself. Regulators must attempt to find a middle ground that appropriately balances incentives and safeguards, particularly in the initial stages of implementation.

5. CRITICAL PBR IMPLEMENTATION ISSUES

PBR has generally been viewed as a simpler, less costly, and more transparent form of regulation than COS/ROR. However, there are many challenges in implementing a PBR scheme, and experience has shown that achieving the benefits of PBR is not necessarily simple or easy.

5.1 INTERNAL FACTORS

One of the most important issues in PBR implementation is the process selected for setting initial rates. Rates should be just and equitable and allow the utility an appropriate return. Some prior applications of PBR have employed rate freezes or updated COS studies to determine going-in rates. In other cases, benchmarking or negotiations have been employed. Implementation problems have arisen in circumstances where the PBR was being implemented together with privatization or where current rates had been set sometime previously and technological or institutional changes had undermined the connection between rates and returns.

Second, failure to fully understand the technical intricacies of correctly specified PBR adjustment formulas has often resulted in rapid and substantial increases in provider rates of return. These results have been observed across countries (e.g., United Kingdom and United States), across industries (e.g., electricity, telecommunications, and coal) and across firms subject to the adjustment formulas. For example, local telecommunications providers subject to the U.S. Federal Communication Commission's price cap plan experienced pervasive, substantial, and immediate growth in rates of return in excess of the prior ceiling. In some cases, rates of return rose almost 80% in four years. In the United Kingdom, both electricity distribution companies and the incumbent telecommunications provider experienced significantly increased earnings. Appropriate rate adjustments would have produced substantially lower prices for residential and industrial end-users and a more level playing field for competitors.

For firms subject to such PBRs, the response by regulators has generally been to schedule more frequent and detailed reviews. This has often revealed unanticipated over-earnings and been followed by repeated increases in the X factor. For example, both the United Kingdom and the United States telecommunications regulators increased the plans' X factors by more than 100 percent over a series of adjustments. Lags in regulatory adjustments to the plans' parameters, however, have necessitated almost continuous proceedings to develop corrective actions. In the case of U.K. electric distribution companies, the government ultimately applied a retroactive windfall profits tax. In fact, a better understanding of the subtleties and potential biases of PBR adjustment formulas would have mitigated most of these implementation problems.

Third, while early implementation of PBR plans often failed to specify standards for quality, service, and/or safety, performance deterioration prompted regulators and other stakeholders to re-evaluate plan incentive structures. Such performance degradation issues have arisen in a number of PBR applications including electricity and telecommunications plans. Clearly, regulators may have been surprised at the magnitude of the efficiency response by many firms to profit incentives; that some of this increase in profits was, or was believed to be, based on cuts in important service, quality, or safety standards prompted significant rethinking in subsequent PBR implementations. In fact, regulators must be cognizant to set incentives for firm behavior within the set of opportunities deemed consistent with regulatory objectives and obligations.

Fourth, regulators must balance increased incentive on the part of the utility, with appropriate regulatory review of the utility's performance in determining the plan's term (i.e., length). Frequent reviews (i.e., short terms) decrease the firm's incentive to improve since such improvements become the basis for updated performance benchmarks. In the limit, price cap plans with very short time horizons tend toward COS/ROR regulation with little regulatory lag. On the other hand, an appropriate plan term allows firms the opportunity to benefit from operating efficiencies they undertake while permitting regulators the chance to gauge the effectiveness of the plan either in whole, or in part (e.g., prices, efficiency, service standards, profits).

Finally, PBR plans must specify what events are to be considered as "unforeseen events." Such events, often termed Z factors, are regarded as pass throughs and relax the constraints imposed by price, revenue or earnings constraints.

5.2 ECONOMIC AND INDUSTRY FACTORS

Failure to understand the economic, industry, and geographic market environments in which the incumbent operates can also induce unforeseen consequences. Regulators must structure plan designs that are appropriate to the industry, sub-industry and time of implementation.

For example, some regulatory bodies have reacted to the "profit" problem described above by setting the X factors for new industries being regulated by PBR at potentially excessive levels. In a recent ruling on a gas LDC PBR, the Massachusetts Department of Public Utilities (DPU) specified an X factor that required the LDC's productivity growth to exceed aggregate (e.g. industry, national) productivity growth by a substantial premium — just at a time when national productivity was accelerating. A comprehensive study of productivity growth across industries prepared for policy makers [7] indicates that the gas industry generally had productivity growth substantially lower than the overall economy — not the potential of 2.5-3.0 percent growth per year or more implied by the DPU benchmark. While one would expect the implementation of PBR to provide some incentive for gas firms to become more efficient, one might question an X-factor for gas firms that implied a rate of productivity growth similar to that initially imposed on AT&T and British Telecommunications.

Similarly, imposition of high X-factors in cyclical downturns has resulted in a significant worsening of incumbents' financial results when the firm's high observed productivity growth was based more on general economic conditions than management-induced efficiencies. In the case of PacBell, the California Public Utility Commission rescinded its original X-factor for a lower offset rather than penalize shareholders. In fact, failure to recognize differences in productivity growth between different industries or at different points in economic cycles can result in the potential for management to suboptimize relative to its behavior under more appropriate incentives. Such sub-optimal decisions can lower the benefits to stakeholders over the longer run.

5.3 PLAN FLEXIBILITY

Regulators need to take a dynamic view of industry, technological, and regulatory changes. Failure to see the nexus of such issues as constantly evolving — but rather as a static intersection — impedes the effectiveness of the transition. The plan design (i.e., number and composition of baskets, going-in rates) needs to handle appropriate current and potential competitive services.

For example, both electric and gas LDCs may offer competitive services, including meter reading and equipment servicing. In addition, some industry analysts foresee a time when electricity distribution companies will have the technical capability to offer telephony services

[7] F.J. Cronin, et al. 1994. *The Contribution of Transportation to Aggregate and Sectoral Productivity*. Prepared for the Office of Policy Analysis, FHWA, U.S. Department of Transportation. DRI/McGraw Hill.

over their networks as one of the major competitors to local phone companies. As restructuring fosters more of these innovative service offerings, appropriate cost allocation between conventional regulated services and new services becomes more critical. The PBR plan put into effect should allow firms the opportunity to undertake investments and offer new services made possible by changing technologies, market structure or customer profiles, while appropriately allocating the cost and risk of innovative investment. It is imperative that the plan be able to appropriately handle such evolving conditions.

5.4 COMPETITIVE EFFECTS

The plan also needs to consider the impact that it may have on the competitive balance between industries. The Board is contemplating a scheme that will implement PBR for electric distribution utilities. While the competitive balance between the industries should shift in response to the fundamental economics of the industries, it is not so easy to discern whether shifts in market share are attributable to fundamental changes in economics or whether the shift is driven solely by artifacts of the PBR design. Thus, the likely impacts of the PBR design on competition between electric and gas must be assessed.

5.5 BUILDING BLOCKS

Finally, there are issues dealing with the building blocks of the Board's regulation including a prescribed system of accounts, the establishment of rate base, and the grouping of similar utilities for benchmarking purposes that will need to be addressed.

5.6 CONCLUSION

While there are various options available to the Board in its implementation of a PBR scheme for electricity distribution in Ontario, it is clear that there are numerous issues that will need to be addressed so that the benefit of PBR may be realized. Consultative workshops will need to be held to obtain input from stakeholders on implementations issues.

APPENDIX A – CASE STUDIES

This appendix provides an overview of several implementations of PBR for distribution utilities. Two general types of case studies are provided. In Section 1, the experience of the United Kingdom and Norway in regulating distribution companies with PBR schemes is discussed. The next section describes the characteristics of several PBR schemes applied to electric and gas distribution companies. As these schemes have been in place only for a short period of time, these case studies focus more on the technical characteristics of the PBR scheme.

1. EXPERIENCE WITH PBR IN THE UNITED KINGDOM AND NORWAY

1.1 UNITED KINGDOM

The U.K. implemented functional separation and divestiture of the government-owned generation, transmission, and distribution system in 1989-1990. Generation was broken up into three privatized independent generation companies, joining a host of smaller independent power producers. Wholesale transmission was separated into a single common carrier, National Grid. Finally, 12 regional electricity distribution companies (RECs) were created and privatized. The RECs were subject to incentive regulation in 1990 based on price caps. The U.K. therefore has a significant history (8-9 years) both in broad restructuring of the electric sector and in the use of incentive regulation for distribution companies.

1.1.1 Experience

As noted above, the first price caps for the RECs were implemented in 1990. Under the price cap regime, prices for each REC are set to recover embedded costs, operating costs per customer, and operating costs per kWh moved, plus an assumed margin. For each year during a five-year period, the REC may increase this price by no more than the retail price index (RPI) less an assumed productivity adjustment ("X") applicable to network industries. Under the 1990 price caps, the X factor was set at 0%.

From 1990-1995, the RECs achieved strong earnings under the price cap. As was intended by the incentive regime, RECs improved productivity, in some cases reducing staff by 25%. Economic

growth during this period also resulted in higher allowable revenues. Plan parameters may also have contributed to higher earnings by overstating and understating price and productivity changes, respectively. These combinations resulted in returns on equity (ROE) of 20% for most of the RECs.

Although the price caps resulted in savings to retail customers, high ROEs created a strong public perception that the benefits of restructuring were inequitably shared between customers and shareholders. The five-year review in 1995 was viewed as an opportunity to correct the inequity by establishing a lower cap on prices and a more aggressive X factor. While initial proposals appeared to accomplish this correction, intense lobbying by the RECs resulted in a final proposal that largely affirmed the status quo for a second five-year period. With another five years of 20% returns apparently assured, many RECs became attractive takeover targets for financial houses and U.S. utilities looking to expand.

The outcome of the 1995 price review, combined with dissatisfaction over wholesale power bidding system, created a strong public outcry against the restructuring process. The U.K. government responded by conducting a consultative study on how “failures” of the process might be corrected, and by levying a windfall tax on all privatized utilities (i.e., electric, water, and telecom) based on market capitalization. The windfall tax was calculated as 23% of the difference between each utility’s market capitalization at the time of privatization and its value four years later. The total levy was £5.2 billion, of which roughly 30% was paid by the RECs.

Under the new price cap, which limits annual increases to RPI minus 2%, the Office of Electricity Regulation projects that distribution charges will fall by one-third over the second five-year period (1995-2000).

The U.K. energy ministry issued its consultative “green paper” on utility regulation in late spring 1998. The green paper floats several proposals for reforming utility regulation (without regard to political feasibility), including the following:

- The use of an “error correction mechanism” for sharing utility profits above prescribed levels;
- Creation of an independent consumer advocacy body with direct input into regulatory decisions; and,
- Greater access to utility data on earnings and costs to allow more open debate on issues such as price reviews.

Whether the government will act on any of these proposals is unclear at this time. In particular, policymakers and utilities appear opposed to earnings sharing. The one-time windfall tax is generally believed to have addressed the issue of sharing gains with the public.

1.1.2 Lessons Learned

The U.K.'s relatively long history with incentive regulation provides several lessons both in performance results of price caps and in the interplay of politics and policy. Chief lessons include the following:

- Price cap regulation can clearly result in price declines to consumers while simultaneously providing higher returns to utilities;
- Even if ratepayers are seeing price declines they will perceive superior returns to their utilities as inequitable;
- If consumers view one aspect of restructuring as inequitable, they will view the entire process with suspicion;
- A closed process for regulatory reviews, such as exists in the U.K., can add to the perception that utilities are treated too leniently; and,
- The political and economic distortions caused by superior returns to the RECs suggests that regulators need to carefully consider the linkage between prices and returns.

1.2 NORWAY

Norway began the restructuring of its electricity sector with its 1991 Energy Law. The law functionally separated the state-owned generation and wholesale transmission systems in 1994, and allowed the 220 municipal or public distribution systems to contract for electricity supply or use the Nordic spot market. While these systems were functionally separated under the restructuring, none of them were privatized. Roughly 85% of Norway's generation (virtually all hydroelectric) is publicly owned. Norsk Hydro, a private supplier to its affiliate industries, controls two-thirds of the private generation. Norwegian law and custom is generally biased against private and foreign ownership.

Retail electricity prices to the residential sector fell 20% from 1994-1996. Industrial customers have seen larger price declines mainly because of the removal of cross-subsidies. Incentive regulation of distribution companies was initiated in January 1997.

1.2.1 Experience

The Norwegian Water Resources and Energy Administration (NVE) introduced an incentive-based regulation scheme that caps revenues based on a formula permitting the network owner to recover its costs plus a reasonable rate of return. Costs include operation and maintenance, network losses, and a profit tax. Allowable revenues are recalculated each year as a function of price index changes (less a productivity adjustment), and permanent changes to electricity sales (i.e., non weather-related load growth or decline). Actual revenues at variance with allowable revenues are refunded or surcharged to ratepayers as a tariff adjustment. The formula also puts a collar on earnings of plus or minus 7% around the base ROE used to establish allowable revenues. For example, the initial ROE was set at 8.3%. If earnings fell below 1.3%, the company would be allowed to charge ratepayers a higher tariff to achieve 1.3%; conversely, if earnings exceeded 15.3%, tariffs would be reduced.

1.2.2 Lessons Learned

Because the Norway incentive regime is recent, experience with it is limited. Norwegian financiers have expressed concern that the new regime makes bond issues by the distribution companies riskier than they were previously, but information on returns is not yet available. The existence of a hard cap on revenues combined with an absolute cap on earnings of 15.3% appears to limit the earnings potential of Norwegian distributors relative to other network industry incentive regulation plans. This may contribute the perception of greater risk in the financial community.

Furthermore, the hard cap on revenues in each year means that the only way a distributor can improve earnings is to cut costs. While improving productivity is one means to cut costs, mergers offer the opportunity for still greater cost reductions. Initial indications are that several distributors are discussing mergers, and the number of distributors is expected to shrink significantly from 220 over the next five years. If the NVE's goal was to encourage consolidation in distribution, the hard revenue cap appears, at least initially, to be an ideal tool.

2. TECHNICAL CASE STUDIES OF PBR

To illustrate the application of PBR, case studies for four utilities in the U.S, for BC Gas in British Columbia, and for network utilities in New South Wales are presented.

The four utilities in the U.S. are Central Maine Power, Southern California Gas, Southern California Edison, and San Diego Gas and Electric. These utilities are privately-owned vertically integrated utilities that own generation, transmission, distribution and commodity marketing businesses. This paper's consideration of PBR will be limited to the regulation of the network functions.

A summary of the various plans examined is presented in Table 1.

2.1 CENTRAL MAINE POWER

In 1995 the Maine Public Utilities Commission was directed by legislation to study electric restructuring, including full retail access by 2000.

In 1994, prior to the legislative direction, Central Maine Power (CMP) submitted an application for an "Alternative Rate Plan" consisting of a PBR mechanism. The plan accommodates competition and provides for regulatory transition towards a competitive environment.

CMP's objectives in proposing a PBR plan was to obtain competitive pricing flexibility, to achieve pricing stability/predictability, to increase incentives for efficiency and to reduce the regulatory process burden. Its PBR mechanism is a price cap with a term of 5-years and has been in effect since 1995. A mid-term review was to be conducted in 1997. At the end of the term, in 1999, an investigation into whether to continue with the plan and what changes to the plan are required for the subsequent period will be conducted.

2.1.1 Indexed Price Cap

The CMP plan involves a single annual price cap adjustment. The price cap is adjusted annually for inflation, productivity offset, a QF (qualifying facilities) factor, sharing mechanism, and flow through items (e.g. extraordinary items) and mandated costs.

The inflation index used is the prior-year's GDP (Gross Domestic Price) deflator index. The inflation index is reduced by a general productivity offset as well as costs that are not subject to inflation-driven increases such as purchased power contracts for fixed prices with QFs (QF factor). The formula includes a general productivity offset of 1.0% and a QF factor of 0.375, assuming that 37.5% of the utility's costs are not affected by inflation. As an example, if the GDP index for 1995 was 3%, the adjustment index for 1996 would be:

$$(3\% - 1\%) * (1-.375) = 1.25\%$$

2.1.2 Earnings Sharing Mechanism

A profit sharing mechanism is used to adjust the subsequent year's price change if the rate of return is outside of the rate of return band (deadband). The deadband ranges from 350 basis points below the allowed return on equity to 350 basis points above the allowed return on equity. Outside of this deadband, gains and losses are shared equally between customers and shareholders. A price cap decrease equal to 50% of the revenue gains is effected above the deadband and a price cap increase equal to 50% of the revenue losses is effected below the deadband.

2.1.3 Flow Through Items

The flow through factors cover uncontrollable or exogenous cost changes such as changes resulting from restructuring of purchased power agreements with QFs, or due to demand-side management which receive either deferred or reconcilable treatment. In the former case, 50% of

TABLE 1

Comparison Of Case Studies' PBR Plans

	Central Maine Power	**Southern California Gas**	**Southern California Edison**	**San Diego Gas And Electric**	**BC Gas**	**New South Wales Network Utilities**
Term of IR Plan	5-years	5-years	5-years	5-years	3-years	3-years
Years Applied	1995 – 1999	1998-2002	1997 - 2001	1994 – 1998	1998 – 2000	1997-1999
Type of IR Plan	Price Cap	Revenue Cap	Revenue Cap	Revenue Cap	Revenue Cap	Revenue Cap
Inflation Index	GDP	Weighted average for costs of Southern California Gas,Pacific Gas and Electric, and San Diego Gas and Electric	CPI	O&M – Labour and Non-lanour inflationary indices Capital Costs – Regression analysis on customer growth and plant additions	CPI for B.C.	CPI
Productivity 'X' Factor	1.0%	2.1% in 1998 2.2% in 1999 2.3% in 2000 2.4% in 2001 2.5% in 2002	1.2% in 1997 1.4% in 1998 1.6% in 1999 1.6% in 2000 1.6% in 2001	Assumes productivity offsets customer growth at a rate of 1.5% per year. If customer growth >1.5%, X factor increased, if <1.5%, X factor decreased.	2% in 1998 2% in 1999 3% in 2000	Transmission 3% Distribution 0-3.5%
Extraor-dinary Events 'Z' Factor	For extraordinary or exogenous events, and renegotiated purchase contracts	Costs associated with events beyond the scope of the PBR plan.	Nine criteria for Z factors	No criteria specified	Includes changes in judicial, legislative or administrative, accounting principles and rules, and catastrophic events.	N/A

TABLE 1

Comparison Of Case Studies' PBR Plans

	Central Maine Power	**Southern California Gas**	**Southern California Edison**	**San Diego Gas And Electric**	**BC Gas**	**New South Wales Network Utilities**
Growth Factor	NA	Model based on a per customer revenue cap	Incremental cost per new customer times number of customers	See productivity factor		N/A
Earnings-Sharing Mechanisms	Deadband: 350 bp* above or below authorized ROR, sharing outside deadband - 50% ratepayer. Price Cap: Decrease or increase in rates equal to 50% of revenue gain/loss.	Shareholder/Customer 25/75 35/65 45/55 55/45 65/35 75/25 85/15 95/5 100/0	Trigger Mechanism-return adjusted by ½ the change in bond index. No deadband, shareholder gets 100% up to ± 50 bp, 25-100% at 50-300 bp, ratepayer gets 100% at >300 bp. Plan review at >600 bp.	Utility gets 100% of losses up to –300bp, and gains up to +100 bp. At 100-150 bp, 20% to ratepayer and 80% to utility at 150-300 pb, 50% to ratepayer and 50% to utility Plan review at >300 bp	Shared equally between customers and BC Gas.	NA
Service Reliability	Customer average interruption duration, and system average interruption frequency		Duration of outages, and Frequency of outages	Average cumulative service interruption per customer	Number of 3rd party system damage incidents per 1,000 housing starts. Leaks/Km distribution main due to system deterioration. Transmission system annual reportable incidents.	NA
Customer Satisfaction	Survey of phone centre transaction customers	Customer satisfaction with scheduling field call and Service Rep.	Response time, problem resolution, comparison with other services	92% survey response of "very satisfied"		NA

TABLE 1

Comparison Of Case Studies' PBR Plans

	Central Maine Power	**Southern California Gas**	**Southern California Edison**	**San Diego Gas And Electric**	**BC Gas**	**New South Wales Network Utilities**
Customer Service	Utility complaint ratio	Telephone customer service, % of on-time arrival for service call,	NA	NA	Response time to emergency calls. Response time for answering service centre calls.	NA
Health and Safety	NA	employee safety	Number of accidents and illness per 200,000 hours or per 100 employees	Lost time accident frequency measure	NA	NA
Pricing Flexibility	Between cap and marginal cost, if mc >40% below cap, floor is 60% of cap. No more than 3 price changes/year. Special price contracts for guaranteeing load. Cap of 15% bt revenue collected at cap and revenue actually collected.		No Criteria Specified	Benchmarks are national average rates for investor-owned utilities.	NA	Distributors - Pricing Guidelines

*Basis Points

the annual savings or costs associated with restructuring of purchased power contracts is flowed through to the ratepayers and the remaining 50% is accrued to the shareholder. In the latter case, revenue requirements associated with prior year deferred demand-side management spending is to be included in the price change.

2.1.4 Pricing Flexibility

CMP requires flexible pricing in order to retain wholesale customers and related industrial customers, whose loss to the utility are threatened by self-generation options and relocation, and to prevent fuel switching for heating application by residential and commercial customers.

With its PBR plan, CMP may change its prices without Commission approval, as long as it satisfies specific criteria. Price changes outside the criteria require Commission review and approval. The flexibility allows the utility to set prices or price schedules for its existing core customer classes between the price cap and a floor equal to the short-term marginal cost for temporary load and long-term marginal cost for permanent load with certain restrictions. Included in the restrictions are the following: no more than two rate changes per year in addition to any change caused by the annual price cap adjustment, and if marginal costs are more than 40% below prices at the cap, the floor will be 60% of the rate cap price.

The pricing flexibility includes the establishment of new or redefined customer classes with qualification criteria based on end-use market characteristics. In addition, it allows for special rate contracts with individual customers that guarantee their load.

With the pricing flexibility there is a risk that a shortfall in revenue resulting from a pricing option to a select group of customers may result in higher rates to the remaining customers. To mitigate this risk, a cap of 15% between the revenue that would have been collected at the price cap and the revenue actually collected is specified.

The price flexibility allows for the establishment of targeted service rate schedules that will build load that is anticipated to be served on a continuing basis.

2.1.5 Service Quality Performance

The plan also includes PBR mechanisms for service quality performance. Service targets include customer satisfaction, service reliability and customer service. Customer satisfaction is determined through surveys of phone center transaction customers. Service reliability is measured in terms of a Customer Average Interruption Duration Index and a System Average Interruption Frequency Index. Customer service performance is based on a utility complaint ratio. Annual baselines are set for each indicator and a sliding scale penalty mechanism is used if the utility’s performance falls below the established baselines.

2.1.6 Least Cost Planning and Demand-side Management Incentive Mechanism

To ensure that the utility engages in least cost planning and demand-side management as set forth in State energy policy, a DSM incentive mechanism is included in the plan. With this mechanism, the utility incurs a penalty if its DSM savings is below 90% of the targeted DSM savings for the year. If the utility exceeds 100% of the target savings, it will receive a credit that can be used to offset potential penalties in subsequent years.

So far, CMP considers its PBR mechanism to be a success. Within the short time that it has been using the PBR mechanism, CMP has managed to stabilize prices, dissipating the perception of continuous large increases that were prevalent prior to PBR. CMP also has managed to secure a major portion of its load through the price flexibility, regulatory expenses have been reduced, market-driven focus has been sharpened and key steps towards restructuring have been put in place.

2.2 SOUTHERN CALIFORNIA GAS

In December of 1995, the California Public Utilities Commission issued its restructuring order establishing retail open access starting January 1, 1998.

The Southern California Gas (SoCalGas) base rate PBR, that came into effect on January 1, 1998, includes a revenue indexing formula, revenue-sharing, a cost of capital trigger mechanism, a Z-factor and exclusions, service quality, customer satisfaction and safety incentives; and, a monitoring and evaluation program.

The revenue indexing formula incorporates inflation, productivity and customer growth and is as follows:

Year 2 Revenue Requirement/customer = Year 1 Revenue Requirement/customer (1+inflation-X)

2.2.1 Inflation Index

The inflation index is the weighted average of labour O&M, non-labour O&M, and capital-related cost inflation factors for gas operations for SoCalGas, Pacific Gas and Electric and San Diego Gas and Electric.

2.2.2 Productivity Factor

The productivity factor has two components: (1) a historic measure of industry productivity and (2) an additional ramped productivity target based on potential incremental productivity improvement the utility can expect to achieve over and above the first component. In addition, the Commission included a 1% increase to the second component to account for potential rate base reductions under SoCalGas' control. The total productivity factor is 2.1% for year 1, 2.2% for year 2, 2.3% for year 3, 2.4% in year 4, and 2.5% in year 5.

2.2.3 Sharing Mechanism

SoCalGas's PBR plan has a 25 basis point "deadband" above its authorized rate of return to allow for minor fluctuations in operations. Between 25 and 300 basis points above the benchmark, there are eight bands with differing revenue sharing proportions as follows:

25 Basis Points:	25% shareholder	75% ratepayers
50 Basis Points:	35% shareholder	65% ratepayers
75 Basis Points:	45% shareholder	55% ratepayers
100 Basis Points:	55% shareholder	45% ratepayers
125 Basis Points:	65% shareholder	35% ratepayers
150 Basis Points:	75% shareholder	25% ratepayers
200 Basis Points:	85% shareholder	15% ratepayers
250 Basis Points:	95% shareholder	5% ratepayers
300 Basis Points:	100 shareholder	0% ratepayers

2.2.4 Z Factors and Exclusions

The Z factor allows for costs associated with events beyond the scope of the PBR plan to be passed through. SoCalGas notifies the Commission when such an event occurs and provides a detailed account of the event. The notification is followed by a supplement to the annual rate adjustment procedure for review by the Commission.

Some costs that are beyond the control of SoCalGas , or that are handled by existing regulatory mechanisms, are excluded from the 'Z' factor. These costs are subject to adjudication by the Commission and include:

- Catastrophic Event Memorandum Account (CEMA)
- Hazardous Substance Cost Recovery Account (HSCRA)
- Low Emission Vehicle (LEV) Program
- Regulatory Transition Costs
- Wheeler Ridge Interconnection Costs and Revenues
- Mandated Social Programs

- Gas costs and Pipeline Demand Charge
- Costs Imposed by the Commission

2.2.5 Capital Trigger Mechanism

SoCalGas's PBR plan includes a "trigger" in the event of a dramatic change in cost of capital as per the 12-month trailing average yield on long-term Treasury Bonds. If increases exceeds 150 basis points over the rate of return benchmark and is forecasted to continue to do so, rates would automatically be adjusted according to a pre-established formula.

2.2.6 Performance Indicators

SoCalGas' performance indicators include customer satisfaction, service quality and employee safety. Individual targets are set for the three performance areas and performance below the targets result in potential rate reductions.

Customer satisfaction includes:

1. Customer satisfaction with the telephone customer service representative;
2. Customer satisfaction with the scheduling of an appointment for a field call;
3. Satisfaction with the field Appliance Service Representative; and,
4. Percentage of on-time arrival for the service call.

Each of the four targets has a one-point deadband below the target. Below the deadband, the utility is penalized $10,000 per 0.1 point decline for the first point below the deadband, and $20,000 per 0.1 point thereafter.

In addition, the call centre performance standard requires 80% of the telephone calls to be answered within 60 seconds for regular calls, and 90% of all leak and emergency calls to answered within 20 seconds.

SoCalGas is responsible for providing quarterly reports to the Commission with monthly data on some of the performance indicators. Total penalties of more than $4 million will trigger a Commission investigation.

Employee safety measures the number of incidents per 20,000 hours worked. The annual benchmark is the California Occupational Safety and Health Administration's (OSHA) Recordable Injury and Illness rate currently at 9.3 incidents with a deadband around the benchmark of 1.0. Penalties or rewards are imposed above and below the deadband, respectively at $20,000 per 0.1 point.

2.2.7 Monitoring and Evaluation

SoCalGas is required to file an annual PBR performance report that reviews the PBR performance, earnings sharing, service quality, customer satisfaction, and safety incentives.

2.3 SOUTHERN CALIFORNIA EDISON

The Commission order for Southern California Edison's (SCE), an electricity utility, states that it considers PBR an alternative to the traditional regulatory model which links costs directly to rates and does not include an independent and explicit incentive to increase efficiency through lowered costs. To encourage efficiency, PBR breaks the feedback link from costs to rates and includes an incentive for the utility to reduce costs. PBR must include appropriate service and safety standards. PBR is seen as emulating the competitive process to encourage utility management to make efficient decisions.

SCE's PBR mechanism for transmission and distribution (non-generation) is a revenue cap and modified price cap plan. The plan has a 5-year term which started in January of 1997 and extends to December 2001. When the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission adopt a separation of both the rate base and base rate revenue requirement between transmission and distribution, the current PBR plan will continue for distribution only. The plan incorporates an escalation index for inflation, incremental revenues for customer growth, productivity offset, a sharing mechanism, and adjustments for extraordinary items (Z factor).

2.3.1 Inflation Index

The inflation index used in SCE's PBR plan is the CPI. However, because the CPI includes prices of inputs used by all industries and not just the electricity industry, the Commission asked SCE to complete a study that defines an industry-specific price index for their mid-term review.

2.3.2 Customer Growth Measure

SCE's PBR plan includes a customer growth measure to ensure that the ne customer allowance is added to the revenue requirement. Without this adjustment, the prices would decline in the subsequent years when the unadjusted revenue requirement is divided by the increased sales associated with customer growth.

The customer growth adjustment used is the incremental cost per new customer times the number of new customers expected in the year. The most current historical value for customer growth is used as an estimate for the expected number of new customers.

2.3.3 Productivity Measure

SCE included a non-generation productivity value of 0.9% based on a 1995 SCE total productivity factor and added a stretch factor of 0.5% to it to obtain a proposed value of 1.4%. The Commission convinced that SCE will discover opportunities for cost reductions as it works with employees over the course of the PBR plan term, adopted a productivity measure of 1.2% for 1997, 1.4% for 1998 and 1.6% for 1999 through 2001.

In its decision the Commission expressed its preference for a productivity factor in the range of 2%. In its mind, the productivity factors for the term of the PBR plan represent a continuation of business rather than a level that would force a fundamental change in culture and strategy to meet the new competitive environment. However, with the opportunity of revisiting the productivity factor at the mid-term review, the Commission supported the revised proposal.

2.3.4 Earnings Sharing Mechanism

If SCE achieves higher productivity than the plan stipulates, a revenue-sharing mechanism will share the cost reductions with the ratepayers. The sharing mechanism is intended to give SCE an incentive to achieve higher productivity and give ratepayers a substantial share of the cost reductions.

The sharing mechanism is based on net revenue and is built around a benchmark of the authorized return on equity. The plan includes a trigger mechanism that adjusts the return on equity by half the value of the change in the bond index to reflect expected inflation.

The shareholders receive all the gains/losses up to 50 basis points around the benchmark. The rationale is that this assigns the gains/losses associated with routine operation, such as effect of temperature on revenue, to the shareholders. Between 50 and 300 basis points, the shareholders' share rises from 25 through 100 per cent while the ratepayers' share declines from 75 to 0 per cent. All gains/losses above 300 basis points are assigned to the ratepayers.

Should the earned return fall in excess of 600 basis points below the benchmark, SCE has the option of applying for reconsideration of the sharing mechanism and the PBR plan. If the earned return rises in excess of 600 basis point above the benchmark, SCE is required to apply for reconsideration of the sharing mechanism and PBR plan.

2.3.5 Z Factors

A set of criteria were established to assess items that might be included as unexpected or extraordinary events (Z factors). The criteria are that the event must be exogenous to the utility; occur after implementation of the PBR plan; have costs that cannot be controlled; have costs that are not a normal part of doing business; affects the utility disproportionately; have costs that are not implicitly included in the PBR plan; have costs that must have a major impact on the utility; and, have costs that must be reasonably incurred by the utility.

The Electric Revenue Adjustment Mechanism (ERAM) allows the utility to recover, in a subsequent year price adjustment, its authorized level of base price revenue requirement when actual and expected sales differ. The divergence may be due to daily variation in temperature, variation in local economic conditions, or long-term effects due to energy conservation. The ERAM allows the utility to recover its authorized level of base rate revenue requirement despite sales fluctuations resulting from these factors.

2.3.6 Service Quality Performance

SCE's PBR plan includes PBR mechanisms for the following service quality indicators: service reliability, customer satisfaction, and health and safety.

The two PBR mechanisms included for service reliability are duration of outages and frequency of outages. The performance standards are based on performance history and a rolling 2-year average is used to accommodate the year-to-year statistical variability. A reward and penalty mechanism is used for both service quality indicators with a deadband around the standard within which there are no rewards or penalties.

For performance in customer satisfaction, SCE is using an external company to conduct a survey of a sample of customers on aspects such as response time, problem resolution, and customer comparison of SCE customer service with similar service contacts. The performance history standard is used as the standard with a reward and penalty mechanism included.

The standard for health and safety is the ratio of the total number of accidents and illnesses per 200,000 hours worked or per 100 employees. The standard is based on data from the past seven years. The mechanism has a deadband around the standard and a reward and penalty scheme outside of the deadband.

2.4 SAN DIEGO GAS AND ELECTRIC

As in the case of SCE , San Diego Gas and Electric (SDG&E) is faced with California's introduction of retail open access in January of 1998. SDG&E's PBR plan is a revenue cap with a five-year term, from 1994 through 1998.

SDG&E's objectives are to move to market-driven decision making and to reduce the significant burden and inefficiency that arise from traditional regulatory oversight. Its PBR plan is intended to enhance the potential benefits of market forces to its customers, to provide reasonable, effective and continuing oversight by the Commission, and to allocate risks and rewards reasonably among ratepayers and stockholders.

SDG&E has three PBR plans: a gas procurement mechanism, an electric generation and dispatch mechanism, and a base rate mechanism. The base rate mechanism is a PBR plan that sets the revenue cap for operating, maintenance and capital expenses. This is the only one of the three mechanisms described here since it is the mechanism relevant for the purpose of this report.

SDG&E's base rate PBR plan includes an annual revenue requirement mechanism, a revenue sharing mechanism, performance indicators, and a monitoring and evaluation procedure.

2.4.1 Revenue Requirement

SDG&E's plan has separate revenue cap formulas for (1) operating and maintenance expenses, and (2) capital costs.

The PBR formula for the operating and maintenance revenue cap includes labour and non-labour inflationary indices. Further, the formula assumes that productivity offsets customer growth at a rate of 1.5% per year. Thus, if customer growth is greater than 1.5%, the customer growth/productivity adjustment factor is increased. If customer growth is less than 1.5%, the customer growth/productivity adjustment factor is decreased.

Capital related costs are estimated using regression analysis between customer growth and plant additions.

2.4.2 Earnings Sharing Mechanism

The allowed rate of return on rate base will continue to be determined as it was with COS/ROR regulation. The earnings-sharing mechanism compares the rate of return earned in the historical 12-month period to the authorized rate of return. A revenue-sharing mechanism has the utility taking sole responsibility for losses up to 300 basis points below the authorized rate of return, and gains up to 100 basis points above the authorized rate of return. At 100 to 150 basis points above the authorized rate of return the gains are shared between the ratepayers and the shareholders at a ratio of 1:4. At 150 to 300 basis points above the authorized rate of return gains are shared equally between ratepayers and shareholders. At 300 basis points above the authorized rate of return, a review is triggered.

2.4.3 Performance Indicators

PBR mechanisms are included for the following performance indicators: employee safety, customer satisfaction, service reliability, and electricity rates.

In employee safety, the utility can earn up to $3 million for coming below the benchmark, and can be penalized up to $5 million if the benchmark is exceeded. The criterion used is the lost time accident frequency measure used by OSHA. The benchmark, set at 1.20 units, is based on SDG&E's historic performance. Performance above or below the OSHA standard provides for higher rewards or penalties.

For customer satisfaction the criterion used is the utility's Customer Service Monitoring System (CSMS) results for the previous year with the benchmark set at a 92% survey response level of "very satisfied". Rewards and penalties increase symmetrically around the benchmark up to a maximum reward of $2 million for a survey indicating a 95% or greater response level of "very satisfied", and a maximum penalty of $2 million for a survey indicating a 89% or lower response level of "very satisfied".

The service reliability criterion used is the utility's System Average Interruption Duration Index. This index is the average cumulative service interruption duration per customer, exclusive of events such as earthquakes and severe storms. The benchmark is set at 70 minutes. The reward or penalty is $200,000 per minute.

The benchmark for pricing PBR mechanisms are the national average prices for investor-owned utilities. In recent years, SDG&E's rates have been at about 149% to 129% of this benchmark. The benchmark will decline by 1% a year reaching 132% in 1998. The utility will be rewarded $1 million for each 0.5% below the benchmark, and will be penalized $1 million for each 0.5% above the benchmark.

2.4.4 Monitoring and Evaluation

A monitoring and evaluation system is in place to assure that adequate data is available for the Commission to monitor and evaluate the program. The monitoring program includes semi-annual reports and a mid-point review for "fine-tuning" of data collection. The evaluation plan requires annual reports with the utility's management evaluation, and an independent review by the Commission. The monitoring and evaluation process will form the basis for the decision to continue, modify or discontinue the PBR plan.

2.5 BC GAS

BC Gas's plan is a revenue cap with a term of 3-years from 1998 to December 31, 2000.

2.5.1 Inflation Index

The CPI for British Columbia will be applied to the elements of the revenue requirement determination methodology that are dependent on inflation. The B.C. CPI forecast by the Toronto-Dominion Bank, the Royal Bank of Canada, B.C. Ministry of Finance and the Conference Board of Canada is used.

2.5.2 Productivity

The Productivity factor for 1998, 1999 and 2000 is 2%, 2% and 3%, respectively.

2.5.3 Capital Structure

The common equity thickness for BC Gas is set at 33%.

2.5.4 Rate of Return on Equity

The rate of return on common equity will be determined annually according to the B.C. Utilities Commission's automatic rate of return adjustment mechanism.

2.5.5 Exogenous Factors

BC Gas' cost of service will be adjusted for exogenous factors beyond the control of the utility. These include: judicial, legislative or administrative changes, orders and directions, changes in generally accepted accounting principles and rules, catastrophic events bypass or other similar events not reflected in the rates.

2.5.6 Earnings Sharing Mechanism

Earnings variances (positive or negative) from the authorized level of earnings, net of incentive earnings, will be shared equally between the customers and BC Gas.

2.5.7 Service Quality Indicators

BC Gas' service quality indicators include:

- Response time to emergency calls.
- Response time for answering service centre calls by a person.

- Leaks per kilometre of distribution mains due to system deterioration.
- Transmission system annual reportable incidents.
- Number of third party distribution system damage incidents per 1000 housing starts.

The annual evaluation criteria are as follows:

- Benchmarks are calculated as the rolling average of the three years prior to the most current year. Performance indicators will be calculated as the rolling average of the most average of the most current year plus the past two years.
- Performance indicators will be evaluated on its own merits and a material deviation form the benchmark for a single performance indicator is sufficient basis to argue service quality deterioration and to limit payments to BC Gas.
- Each performance indicator is to be give equal weight.
- The responsibility of establishing whether the benchmark was met or why it is reasonable that it was not met rests with BC Gas.
- Interested parties should have access to the service quality evaluations prior to the Annual Review.
- Any party may argue for the modification of the benchmarks.

BC Gas' plan also includes incentives for Demand-Side Management.

2.5.8 Operating and Maintenance Costs

The operating and maintenance costs for each year is determined using the following formula:

[Base Cost x (1 + Growth in Customers - Productivity) x (1 + Inflation)] + Cost of Incremental Activities

2.6 NEW SOUTH WALES, AUSTRALIA

The Independent Pricing and Regulatory Tribunal (IPART) of New South Wales in Australia regulates the prices of the six electricity distributors serving the region. Separate revenue cap formulas are used to regulate the network and supply charges. Since this paper is concerned with the regulation of network systems, only the revenue cap for the network charges are described.

While a revenue cap is used in the regulation of the network systems, there was no mention of performance measures for reliability and quality of service in the description of the plan.

The transmission system's (TransGrid) rate order covers the period 1996-1999. For March 1996 through June 1997 the monopoly transmission services revenue was capped at $355 million.

For July, 1997 to June 1999 Transgrid's revenue will be adjusted and capped using the following formula:

Maximum Revenue = [Fixed Charge * (CPI - X)] +
[(Energy Charge * Projected Peak and Shoulder kWh) * (CPI-X)]
[(Demand Charge * Projected demand Mwh) * (CPI -X)]

The CPI used is the increase in the average of the all-groups for the city of Sydney for the four quarters to March relative to the index for the same period in the previous year.

The distributors' rate order is in effect from June 1997 to June, 1999. The revenue cap formula is as follows:

$$DOUSC = [\{a+(b_1N_1 + b_2N_2 + b_3N_3) + cM+dL+K\}*\{1+(CPI-X\}] + QT$$

Where DOUSC = Distribution Use of System Charges = Total Network Revenue

$N_{1,2,3}$	=	Customer number by customer size
K	=	Loss adjustment factor
M	=	MWh sales
L	=	Circuit Kilometres (applies to rural distributors only)
a	=	Residual constant capturing other costs,
b	=	dollar margin per customer for each customer size
c	=	Dollar margin per MWh
d	=	Dollars per circuit kilometres
CPI	=	increase in average of the all-groups CPI for Sydney for the four quarters to March relative to the index for the same period in the previous year
QT	=	Payments by NorthPower for Queensland transmission costs for supply to customers in Tweed (customers in Tweed are currently supplied by Queensland).

2.6.1 Productivity Factor

The X factor for the distributors ranges from 0.0% to 3.5%.

2.6.2 Trigger Mechanism

The distributors must maintain an 'Unders-and-Overs' account to keep track of variations between the allowable revenue and actual revenue. Action required upon deviation from the cap is as follows:

Tolerance	Action
Less than ± 2%	As part of ongoing compliance, notify IPART within 30 days of year-end.
Between ± 2% and ± 5%	Notify IPART within 30 days of year-end with Action Plan to resolve balance within the term of the price path
Greater than ± 5%	Notify IPART within 30 days of year-end. After consultation, immediate action by the distributor will be required.

2.6.3 Pricing

In addition to the revenue cap formula the distributors have side constraints on their network prices including the limitations described below.

2.6.4 Residential Tariffs

Any increase in the bill of any individual residential customer may not exceed the greater of:

- CPI; or
- For customers on non- off-peak tariffs, $5.00 per quarter; or
- For customers on off-peak tariffs, $7.00 per quarter.

Any increase in the average residential tariff for the total residential group may not exceed 80 percent of the applicable CPI.

2.6.5 Rural Rates

Any increase in the domestic component of a rural tariff is also subject to the same preceding constraints applicable to the bill of a residential customer.

2.6.6 Commercial or Industrial Customers

The bill for any commercial or industrial customer may not increase by more than the greater of:

- 5 percent in real terms, or
- $50 per annum.